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DISSERTATION



Improving Cost-Effectiveness and Mitigating Risks of Renewable Energy Requirements

James Griffin

This document was submitted as a dissertation in September 2008 in partial fulfillment of the requirements of the doctoral degree in public policy analysis at the Pardee RAND Graduate School. The faculty committee that supervised and approved the dissertation consisted of Robert J. Lempert (Chair), Michael A. Toman, and Steven W. Popper.



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Abstract

Policy makers at the federal and state levels of government are debating actions to reduce U.S. greenhouse gas emissions and dependence on oil as an energy source. Several concerns drive this debate: sharp rises in energy prices, increasing unease about the risks of climate change, energy security, and interest in expanding the domestic renewable energy industry. Renewable energy requirements are frequently proposed to address these concerns, and are currently in place, in various forms, at the federal and state levels of government. These policies specify that a certain portion of the energy supply come from renewable energy sources. This dissertation focuses on a specific proposal, known as 25 x 25, which requires 25% of electricity and motor vehicle transportation fuels supplied to U.S. consumers to come from renewable energy sources, such as wind power and ethanol, by 2025.

This dissertation builds on prior energy policy analysis, and more specifically analyses of renewable energy requirements, by assessing the social welfare implications of a 25 x 25 policy and applying new methods of uncertainty analysis to multiple policy options decision makers can use to implement the policy. These methods identify policy options that can improve the cost-effectiveness and reduce the risks of renewable energy requirements. While the dissertation focuses on a specific policy, the research methods and findings are applicable to other renewable energy requirement policies.

In the dissertation, I analyze six strategies for implementing a 25 x 25 policy across several hundred scenarios that represent plausible futures for uncertainties in energy markets, such as renewable energy costs, energy demand, and fossil fuel prices. The strategies vary in the availability of resources that qualify towards the policy requirement and the use of a “safety valve” that allows refiners and utilities to pay a constant fee after renewable energy costs reach a predetermined threshold. I test each strategy across the set of scenarios and conclude that an “all-combined” strategy—one that allows greater corn ethanol production and energy efficiency to qualify towards the requirement and includes a safety valve—is the most robust strategy to address future uncertainties in energy markets.

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ABBREVIATIONS

AAM	Alliance of Automobile Manufacturers
AEO	<i>Annual Energy Outlook</i>
BTU	British thermal unit
CCS	carbon capture and sequestration
CO	carbon monoxide
CO ₂	carbon dioxide
CSE	cost of saved energy
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
EERE	Office of Energy Efficiency and Renewable Energy
EFC	Energy Future Coalition
EGS	enhanced geothermal systems
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EU	European Union
FT	Fischer-Tropsch
GHG	greenhouse gas
GIS	geographic information system
GW	Gigawatts
GWh	gigawatt-hour
HC	hydrocarbon
ICE	internal combustion engine
IGCC	integrated-gasification combined cycle
KWh	kilowatt-hour
LBL	Lawrence Berkeley National Lab
LCOE	levelized cost of electricity
LHS	Latin hypercube sampling

MB/D	million barrels per day
MIT	Massachusetts Institute of Technology
MJ	megajoule
MMBTU	thousand thousand British thermal units
MTG	methanol-to-gasoline
MW	megawatt
NCEP	National Commission on Energy Policy
NEMS	National Energy Modeling System
NO _x	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OPEC	Organization of the Petroleum Exporting Countries
PDF	probability distribution function
PM	particulate matter
PV	photovoltaic
R&D	research and development
RDM	robust decision making
RIA	Regulatory Impact Analysis
RFF	Resources for the Future
RFS	Renewable Fuels Standard
RPS	Renewable Portfolio Standard
SO ₂	sulfur dioxide
USDA	U.S. Department of Agriculture
UT	University of Tennessee
WGA	Western Governors' Association
WinDS	Wind Deployment System Model

CHAPTER 1: INTRODUCTION

Policy makers in Washington and state capitols throughout the nation are debating actions to reduce greenhouse gas emissions and dependence on oil as an energy source. Several concerns drive this debate: sharp rises in energy prices, increasing unease about the risks of climate change, energy security, and interest in expanding the domestic renewable energy industry. Renewable energy requirements are frequently proposed to address these concerns, and are currently in place, in various forms, at the federal and state levels of government. These policies specify a certain portion of the energy supply from renewable energy, either as an absolute amount of renewable energy supplied into the market or as a percentage of the energy supply. In the electricity market, these requirements are generally known as Renewable Portfolio Standards (RPS), and in the motor vehicle transportation fuels market, they are referred to as Renewable Fuel Standards (RFS). The details of individual requirements and the energy sources that qualify under them vary considerably. The requirements generally include electricity from wind, solar, hydroelectric, geothermal, wave, tidal, landfill waste, and biomass sources. For motor vehicle transportation fuels, the requirements typically include ethanol and biodiesel. Most requirements exclude fossil fuels (coal, natural gas, and oil) and nuclear power¹ but sometimes allow combined heat and power systems fueled by fossil fuels.

OBJECTIVE

This research will identify options to improve the cost-effectiveness and reduce the risks of using renewable energy requirements to address societal concerns about climate change and energy security. The dissertation will focus on a specific policy proposal, known as a 25 x 25 policy, which requires 25% of electricity and motor vehicle transportation fuels supplied to United States consumers to come from renewable energy sources by 2025.

The dissertation will assess this proposal by addressing the following research questions:

- 1) *What are the potential implications of a 25% renewable energy requirement in electricity and motor vehicle transportation fuels by 2025 for overall economic well-being (consumer plus producer surplus) and greenhouse gas emissions, under the broad range of uncertainties affecting energy markets?*

¹ Ohio allows clean coal and advanced nuclear power in addition to renewable electricity in the state's "Alternative Energy Resource Standard" (DSIRE, 2008a).

- 2) *What are the currently uncertain key factors leading to high-cost and low-cost outcomes under a 25% renewable energy requirement?*
- 3) *How does the cost-effectiveness of the renewable energy requirement compare with other policy options that reduce greenhouse gas emissions?*
- 4) *What options in designing the requirement can improve cost-effectiveness?*
- 5) *How can policymakers mitigate risks of high-cost outcomes under the requirement?*

This research builds on prior analysis of renewable energy requirement policies by assessing a requirement imposed on multiple energy markets with a high level of renewable energy penetration. In addition, earlier studies on a 25 x 25 requirement did not analyze the policy's effects on social welfare (consumer and producer surplus), which is the traditional metric of a policy's costs in economic analysis (English et al., 2006; EIA, 2007c; Toman et al., 2008). Furthermore, this study applies new methods of uncertainty analysis to multiple options decision makers can use to implement the policy. Most previous studies considered one to at most a few predefined scenarios of future energy markets and analyzed one option to implement the policy. As will be described in detail later, the key scenarios in this study emerge from the analysis and by analyzing several policy options I identify those that can improve the cost-effectiveness and reduce the risks of the 25 x 25 requirement. Finally, while this dissertation focuses on a specific policy, the research methods are applicable to energy policy analysis more broadly, and the findings are relevant to decision makers considering other renewable energy requirement policies with lower or higher percentage targets.

The remainder of this chapter discusses background information that is important to understanding this analysis of renewable energy requirements. This discussion includes information on the current use of renewable energy in the United States, key policy concerns in the debate over increasing renewable energy use, descriptions of the renewable energy technologies included in the analysis, and existing research in this area. Chapter 2 describes the analytical methods and models used in the analysis. Chapter 3 shows results for an initial strategy to implement the 25 x 25 policy and highlights the vulnerabilities of this strategy. Chapter 4 analyzes several alternative strategies that expand the set of resources that qualify towards the renewable energy requirement and explicitly limit the costs of this policy. The goal of this analysis is to identify strategies that are less sensitive to the factors leading to high costs under the initial strategy. Chapter 5 offers conclusions from the analysis. Finally, a Technical Appendix describes the analytical models in detail.

BACKGROUND AND MOTIVATION

25 x 25 Policy

This dissertation analyzes a specific policy proposal known as 25 x 25, which requires U.S. utilities and refiners to supply 25% of the energy delivered to consumers from renewable energy sources by 2025. In analyzing this policy, I make several choices involving the technologies qualifying towards the requirement, the sectors included in the analysis, and type of energy demand used to calculate the requirement (delivered energy vs. primary energy demand). I include demand for electricity from electric utilities and total gasoline and diesel consumption by light-duty vehicles, commercial trucks, and freight trucks. Of note, this excludes the demand for transportation fuels in the air, marine, and rail sectors. I selected these sectors because existing renewable energy requirements target these sectors. In addition, current renewable energy technologies are most substitutable for electricity and liquid fuels used in the transportation sectors included in the analysis. Chapter 2 and the Technical Appendix describe the choices I made in implementing this policy in greater detail.

In 2005, the Energy Future Coalition (EFC) asked RAND to analyze the effects of a 25 x 25 policy on U.S. energy expenditures and greenhouse gas (GHG) emissions. Toman et al. (2008) shows the results of that analysis and this dissertation extends the models developed for that project to assess the social welfare implications of the policy requirement. This dissertation also evaluates several new policy options decision makers can use in implementing the requirement. These options include: unconstrained corn ethanol production, allowing energy efficiency to qualify towards the requirement, and using a safety valve to contain costs.

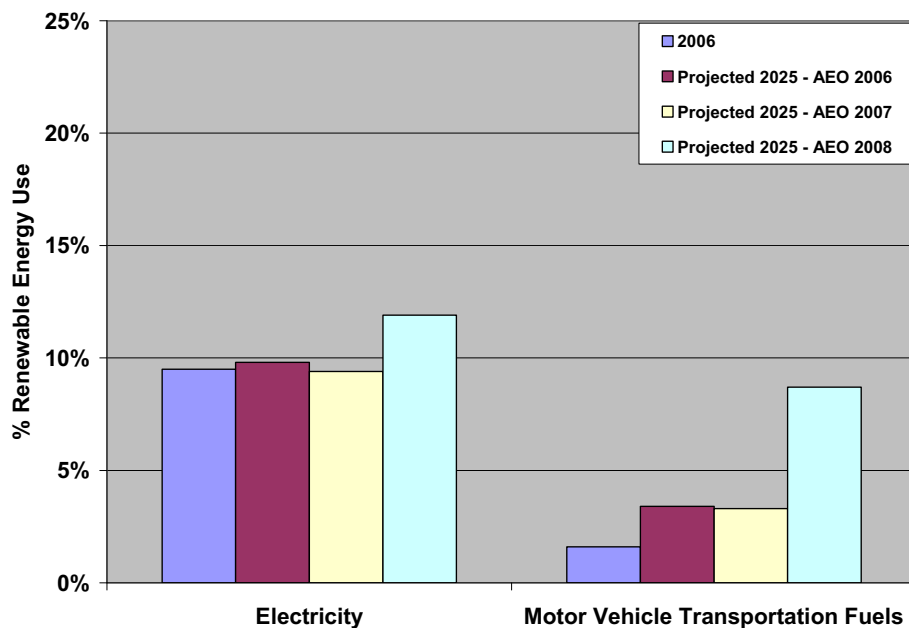
The EFC's proposal for a 25 x 25 requirement is part of broader interest in this specific policy and renewable energy requirements in general. In 2007, Senator Inhofe (R-Okla.) requested the Department of Energy's Energy Information Administration (EIA) to analyze a 25 x 25 policy requirement implemented in the electricity and motor vehicle transportation fuels sectors. The policy analyzed in this dissertation closely follows this 25 x 25 proposal analyzed by EIA. The 25 x '25 Alliance is currently organizing a grass-roots campaign with a vision that, "by the year 2025, America's farms, ranches and forests will provide 25 percent of the total energy consumed in the United States, while continuing to produce safe, abundant and affordable food, feed, and fiber" (25 x '25 Alliance, 2007, p.2). The proposal by the 25 x '25 Alliance would expand renewable energy use beyond the level in the 25 x 25 proposal analyzed by the EIA and this analysis because it proposes 25% renewable energy for total energy consumption (electricity

and motor vehicle transportation fuels comprise about two-thirds of total energy consumption). Currently, 22 Governors have endorsed the 25 x '25 Vision and 14 state legislatures have passed resolutions supporting the campaign. Finally, the U.S. Congress passed a resolution supporting the 25 x '25 Vision, which was contained in the Energy Independence and Security Act (EISA) of 2007.

Policy makers at both the federal and state levels of government are also considering similar proposals. The U.S. Congress has debated several proposals for a national-level RPS between 15% and 20%, but none of these measures have passed. California recently proposed increasing the state's RPS from 20% to 33% and a low-carbon fuels standard that would lower carbon intensity in the fuel supply by 10% as key policies to meet the state's GHG reduction targets established in 2006. In Senator Obama's "New Energy for America" plan, he proposes a 25% RPS by 2025 and decreasing carbon intensity of motor fuels 10% by 2020. Therefore, while this dissertation analyses a specific proposal, the policy options considered are broadly applicable to other proposals. Furthermore, the range of supply curves used in the analysis can provide insight into the costs of other proposals with lower or higher requirement levels.

All of these proposals would increase renewable energy use substantially from current levels and beyond projected use in 2025. Figure 1 shows current and 2025 projected U.S. renewable energy use, according to the EIA.

Figure 1: Current and 2025 Projected Renewable Energy Use



Sources: EIA, 2006a, 2007a, 2008a.

The graph shows that renewable electricity currently supplies about 10% of electricity demand. In its Annual Energy Outlook ²(AEO) 2006 and 2007, the EIA did not project this proportion to grow significantly by 2025. The AEO 2008 shows the percentage of renewable electricity in 2025 increasing to 12%. Large hydroelectric dams produce over three-quarters of the current renewable electricity in the U.S. and this trend persists in these projections. Renewable fuels comprise an even smaller portion (2%) of projected motor vehicle transportation fuel demand. In the AEO 2006 and 2007, the EIA anticipated modest growth in these renewable energy sources to just over 3% of fuel demand. The AEO 2008 projects the proportion of renewable fuels to grow to 9% by 2025, which is nearly triple the projections in the AEO 2006 and 2007. The AEO 2008 projects greater renewable energy use in both markets because it assumes higher fossil fuel prices than earlier editions and reflects the increase in required biofuels production contained in the EISA. This legislation raised the national RFS to 36 billion gallons by 2022 from an earlier requirement of 7.5 billion gallons of renewable fuels by 2012.

Historically, the U.S. has consumed a limited amount of renewable energy because renewable energy costs exceeded fossil fuels for most energy uses. Even with substantial decreases in costs of many renewable energy technologies, they still remained more costly because fossil fuel technologies also improved efficiency and fossil fuel prices remained low (McVeigh et al., 1999). Several of these trends have changed in recent years though. The most obvious is that oil prices, and the prices of other fossil fuels, rapidly increased and are now projected to remain above the levels predicted even one year ago. Policies to reduce greenhouse gas emissions, especially if they are market-based policies, are likely to further increase the relative prices of fossil fuels (EPA, 2008; EIA 2007d, 2008b, 2008c).

Renewable Energy Requirement Policy Objectives

Proponents of renewable energy requirements argue that increasing the use of renewable energy can benefit society for reasons of economic efficiency, distributional concerns, and foreign policy. Proponents argue that one reason society under-utilizes renewable energy technologies is several market failures in energy markets. Examples of market failures cited by proponents include externalities from greenhouse gas emissions, overdependence on oil, and

² The Annual Energy Outlook is an annual report by the EIA presenting projections and analysis of U.S. energy supply, demand, and prices. The EIA uses their national-level energy-economic model, the National Energy Modeling System (NEMS), to make the projections based on several different scenarios of future energy prices, technological progress, and economic growth.

inadequate incentives to develop new technologies. Proponents also argue that renewable energy use should increase for reasons other than economic efficiency. Some proponents suggest that renewable energy projects would lead to greater investment in domestic energy companies and redirect resources spent on foreign energy supplies to domestic energy producers. Many proponents argue that farmers and rural landowners would significantly benefit from the policy because it would increase demand for new energy crops leading to higher commodity and land prices. Proponents also argue that increasing renewable energy use would improve the U.S. government's latitude in foreign policy and reduce U.S. wealth spent on oil imports that enriches hostile, oil-producing regimes.

Critics of renewable energy requirements argue that such large changes to complicated systems invariably result in unintended consequences. The policy could sharply raise energy prices because the cost of renewable energy at levels far beyond current experience is highly uncertain and potentially very expensive. Another criticism is that the policy requirement relies too heavily on one approach (increasing renewable energy use) to accomplish the intended policy goals and could become costly relative to other policy options. The remainder of this section will discuss these arguments and the existing debate in the literature in greater detail as this discussion sets up many of the policy options analyzed later and the key objectives in increasing renewable energy use.

Improving Economic Efficiency

Neoclassical economic theory states that market failures result in a suboptimal equilibrium that may justify government intervention. The market failures widely cited by proponents include the external effects of greenhouse gas emissions, health impacts associated with conventional pollutant emissions from fossil fuels, energy security, and innovation in new energy technologies. With these market failures, energy prices fail to account fully for the social costs of fossil fuels and social benefits of renewables resulting in a suboptimal level of renewable energy use. The remainder of this section will discuss these market failures in greater detail and how renewable energy may mitigate the problems.

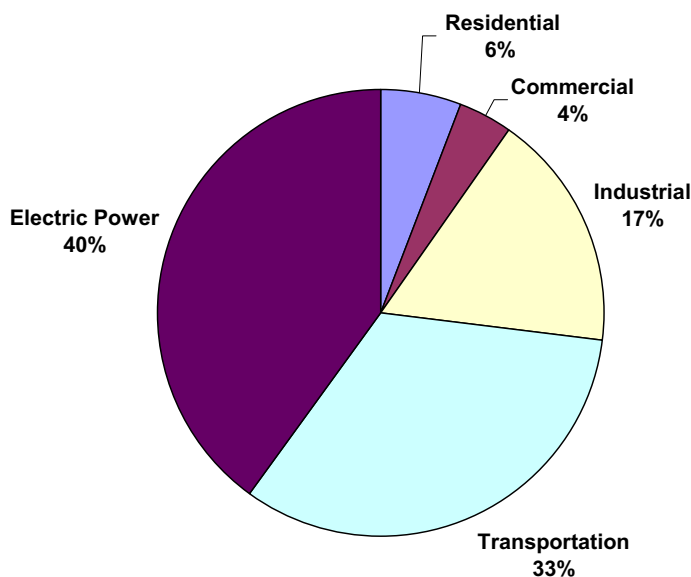
Greenhouse Gas Emissions

The Intergovernmental Panel on Climate Change (IPCC) concluded in their recently completed 4th Assessment Report on Climate Change that anthropogenic greenhouse gas (GHG) emissions very likely caused the observed increase in global average temperatures since the mid-20th century and that stabilizing global mean temperatures by the middle of the 21st century will

require sharp reductions in GHG emissions (IPCC, 2007). The EIA estimates that in the absence of any policies to reduce emissions U.S. GHG emissions will continue to rise at approximately 0.6% per year until 2030 (EIA, 2008a). Based on this projection, U.S. GHG emissions would increase over 2000 levels by 12% in 2025 and 17% in 2030, or 723 million tonnes by 2025 and 1004 million tonnes by 2030. Eliminating these increases and potentially reaching levels far below them would require a significant shift to energy sources with lower carbon intensities, and renewable energy is one of several less carbon-intensive technologies that can substitute for fossil fuels.

Renewable energy advocates argue that the U.S. could substantially reduce aggregate emissions by increasing renewable energy use in the electric power and motor vehicle transportation fuels sectors because these sectors account for almost three quarters of U.S. GHG emissions and the U.S. currently uses limited renewable energy in both sectors (Figure 1). Figure 2 shows the breakdown of GHG emissions in the U.S.

Figure 2: Share of 2006 U.S. Greenhouse Gas Emissions by Sector



Source: EIA, 2007b.

The figure shows that transportation and electric power comprise an estimated 73% of annual emissions in the U.S. Industrial energy uses have the next highest emissions at 17%. Residential

and commercial uses make up the remaining 10%. The EIA's projections show these proportions remaining relatively stable over their analysis period (until 2030) (EIA, 2008a). Most renewable energy technologies provide lower-carbon alternatives to the fossil fuels used in the electricity and transportation sectors and a 25% renewable energy requirement could significantly reduce emissions of greenhouse gases.

Conventional Pollutants and Other Environmental Impacts

Fossil fuels used for electricity and motor vehicle fuels cause pollution and environmental impacts throughout the entire life-cycle. Farrell (2004) notes that electricity production from fossil fuels results in air pollution, water use, solid waste, and problems with compatibility with other land uses. Parry, Walls, and Harrington(2007) state that local air pollution is one of the primary externalities of gasoline-fueled automobile use, which includes emissions of carbon monoxide (CO), nitrogen oxides (NO_x), hydrocarbons (HC), and particulate matter (PM). Displacing these energy sources with renewable energy could potentially decrease the emissions of conventional pollutants and other environmental harms associated with fossil fuels. However, the pollutant emissions and environmental impacts from renewable energy sources vary considerably. Some, such as wind and solar power, have very limited emissions. Some biomass energy sources may exacerbate existing problems though. For instance, Jacobson (2007) found that large-scale conversion to E85³-fueled vehicles would increase ground-level ozone levels in urban areas and increase human health risks from this pollution. Donner and Kucharik (2008) estimated that rising nutrient pollution from increasing corn-based ethanol production to meet the goals of the 2007 RFS could threaten efforts to reduce the seasonal "Dead Zone" in the Gulf of Mexico.

Even if some renewable sources can reduce conventional pollutant emissions, the overall level of emissions may not change. Some pollutants, such as sulfur dioxide, are regulated through a cap-and-trade market. Adding low-emission renewable electricity may reduce these sulfur dioxide emissions per kwh of electricity produced; however, the total amount of sulfur dioxide is still regulated through the limit on emissions. For pollutants that are regulated through a cap-and-trade market, increasing renewable energy would most likely reduce the price of permits in these markets but not decrease the total amount of emissions, unless the policy requirement is accompanied with additional policies that change the mix of electricity generation towards lower polluting sources.

³ E85 refers to a motor vehicle fuel with 85% ethanol and 15% conventional gasoline.

Renewable energy may also shift where pollution occurs, which may improve air quality in some locations but create problems in others. Life-cycle analysis of high-level ethanol blends, such as E85, shows that ethanol production reduces criteria pollutant emissions from oil refineries as ethanol displaces the gasoline produced at these plants but emissions of NOx increase in rural locations near the farms where the energy crops are grown (Brinkman et al., 2005). In this example, increasing renewable energy would displace emissions from urban areas but increase emissions of certain pollutants in rural areas.

Increasing renewable energy may also exacerbate existing environmental problems in certain locations. In a 2002 survey of corn ethanol plants, Shapouri and Gallagher (2005) found that water consumption per gallon of ethanol produced varied from 1 to 11 gallons with an average of 4.7 gallons. Therefore, substantially increasing biomass production may further strain water supply problems where current agricultural practices already use water supplies unsustainably. Ethanol production may also exacerbate water pollution problems, as noted above by Donner and Kucharik (2008). The magnitude of these issues depends critically on many site-specific factors about biomass and biofuels production processes.

Overall, the impact of increasing renewable energy on conventional pollutant emissions and environmental harms from fossil fuels is difficult to generalize because of variability in renewable energy production and site-specific conditions. The overall effect depends on the mix of renewable energy sources produced to meet the requirement and their production processes. A section later in this chapter describes each technology in more detail and will discuss the environmental issues associated with each energy source.

Induced Innovation and Renewable Energy Technology Spillovers

One of the arguments strenuously urged by renewable energy advocates is that a renewable energy requirement will stimulate the investment and innovation needed to reduce the costs of renewables to the level where they can compete with fossil fuels. This quote from Google⁴ (undated) exemplifies this argument made by many advocates:

Renewable Portfolio Standard: A national RPS would require that US utilities produce a specific percentage of electricity from renewable energy and build on similar measures already adopted at the state level. Expanding the market for renewable energy through an RPS – along with incentives such as tax credits - would help renewable energy

⁴ In 2007, Google started several initiatives to promote and invest in renewable energy. Google is also advocating for public policy favoring these technologies (www.google.com/corporate/green/energy/policy.html).

technologies realize the economies of scale that will, over time, drive down their cost and make them competitive with coal-fired generation.

As this quote shows, some renewable energy advocates argue that a requirement can transform renewable energy's competitive position in the marketplace. While renewable energy requirements would undoubtedly stimulate new investment in these technologies (Figure 1 showed that reaching 25% would more than double renewable energy penetration in both markets), a question remains if any market failures exist where the level of investment in the private market would deviate from the socially optimal level. A substantial body of theoretical and empirical research suggests that several market failures may exist in private markets that would lead to suboptimal investments in innovation and diffusion of new technologies. Jaffe, Newell, and Stavins (2003) state that two competing theories exist in this area, which have different implications for renewable energy requirements.

The first theory is neoclassical induced innovation. Under this theory, research and development (R&D) into new technologies is a profit-motivated activity and the rate and direction of innovation will respond to changes in relative prices and constraints placed on firms. Given these incentives, private firms may under-invest in R&D activities for several reasons. The first reason is that firms may have difficulty in securing financing for R&D activities because the profitability of R&D can be highly uncertain and the investment may not have tangible assets. This argument does not reflect a market failure but that investment in R&D is relatively more costly in comparison to other options with lower risk. A second reason is that firms cannot easily exclude others from the knowledge gained from R&D, and for this reason Arrow (1962) first noted that firms are unlikely to appropriate all of the private and social returns to a new innovation. The firm will gain some of the returns but competing firms, downstream firms, and consumers will also gain from the positive spillovers of the innovation (Grilliches, 1979, 1992; Jaffe, 1986, 1998). This inability to fully appropriate from the innovation could lead to underinvestment by private firms (Spence, 1984). These findings do reflect a market failure where the social benefits of investment in R&D deviate from the private benefits realized by firms.

These arguments suggest that policy can affect how firms decide to invest in R&D and induce innovation in certain areas. Since a firm's decision on R&D investments will respond to relative prices, policies that reduce the costs of R&D can stimulate investment. A renewable energy requirement would reduce uncertainty for R&D investments by guaranteeing an

increasing market share for investments in this sector. This policy, however, is not the only instrument that could affect R&D investments. Subsidies that reduce the costs of R&D would also encourage innovation. Prizes that offer large rewards for certain innovations could increase the profitability of R&D investments.

A second theory on technological change asserts an evolutionary approach to innovation. Based on Simon's theory of bounded rationality where firms satisfice according to rules of thumb and established norms instead of optimizing (Simon, 1947), new policies, such as a renewable energy requirement, may not necessarily reduce firms' profits because they force firms to change behavior. In changing behavior from the established norms, firms may find more profitable ways to operate because the existing equilibrium was suboptimal. Porter and van der Linde (1995) refer to these newly discovered profitable opportunities as, "innovation offsets." In applying this theory to a renewable energy requirement, the policy may be less costly than expected because utilities and refiners find cost-saving opportunities to integrate these energy supplies into their system. Because of bounded rationality, firms only find these opportunities after the requirement becomes law. Jaffe, Newell, and Stavins (2003) note that the evolutionary theory of innovation remains controversial. Porter and van der Linde (1995) provide case studies to support the theory but do not offer evidence that the large innovation offsets are systematic through the economy and available with every policy change.

While the previous arguments focused on theories of innovation in new technologies, another body of theory applies to technological diffusion of existing technologies. An additional market failure occurs in this area with important implications for renewable energy technologies. Most renewable energy production processes are characterized by learning by doing where the costs of production decline as output increases. Thus, increasing use of renewable energy has a positive externality of reducing technology costs. Modelers commonly use learning curves in empirical analyses of climate and environmental policy (Grubler and Messner (1999); Grubler, Nakicenovic, and Victor (1999)). Some empirical work has also measured the impact of cumulative output increases on costs. These studies capture the cost changes by estimating a progress ratio, which was first established by Hirsch (1956). The progress ratio describes the rate of cost decrease for each doubling of cumulative capacity in the industry. These empirical estimates have been used in numerous analyses of renewable energy technology (Neij, 1997). In addition, several studies have estimated progress ratios for wind power (Junginger, Faaij, and Turkenburg, 2005) and ethanol (Goldemberg, 1996; Goldemberg et al. 2004a, 2004b). Junginger, Faaij, and Turkenburg (2005) compared estimates for

different countries in Europe and the United States and found a range from 68% to 117%. A progress ratio of 68% means that for each doubling of capacity the cost declined 32%. Ratios over 100% indicate costs increased with the doubling of capacity. Goldemberg analyzed the price paid to ethanol producers by the Brazilian government between 1980 and 1995. In the period from 1980-1990, the subsidy decreased rapidly and he estimated a progress ratio of 70%. The rate decreased in the later period where he found a progress ratio of 90% from 1990-1995. The studies indicate renewable energy technologies have considerable potential for cost reductions, and firms may be unwilling to make the initial investments in these technologies because they may not appropriate all of the gains from reducing renewable energy costs. A renewable energy requirement would increase investment in these technologies and could move several of the technologies down their respective learning curves. Decision makers still need to weigh investments in these technologies against other technologies that can achieve the same goals, such as carbon capture and sequestration (CCS) and increasing energy efficiency. Furthermore, other policies, such as subsidies for renewable energy production, can also increase investment in these technologies.

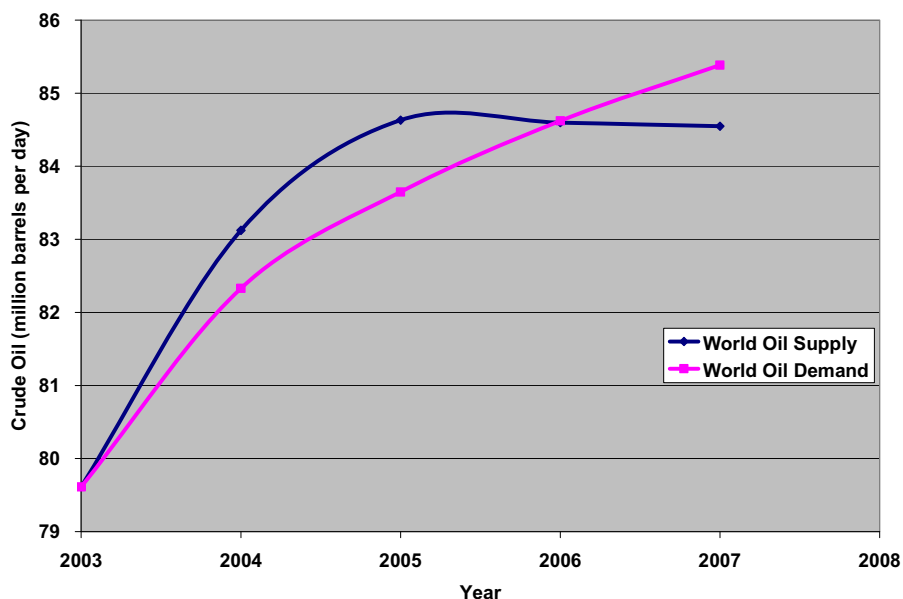
High Oil Prices, Oil Dependence, and Energy Security

With oil prices over \$100 per barrel, U.S. consumers are upset with the rapid rise in energy prices and calling on policy makers to take some action to lower prices. Many consumers and policy makers also worry about the energy security implications of the nation's high reliance on oil as an energy source. The U.S. currently uses oil for 40% of primary energy demand and 98% of transportation sector energy demand (EIA, 2008a). All of these concerns are driving an animated discussion of policy measures to address the current situation in the oil market.

There is no question oil prices have increased dramatically in the past five years. Since 2003, oil prices have risen steadily but starting in the summer of 2007 oil prices sharply increased and reached record territory in inflation-adjusted terms (Borenstein, 2008). While thoroughly unpopular with the oil-consuming public, from the perspective of economic efficiency high oil prices driven by scarcity are not a market failure and do not justify government intervention; however, high oil prices created by producers with market power, such as OPEC, are a market failure that could warrant government intervention. The evidence suggests the recent increase in oil prices is primarily caused by scarcity, but that OPEC also has the market power to potentially affect market prices. I discuss this evidence and the debate in the literature on market power in global oil markets in the following sections.

Data on global oil production and demand show that demand has steadily risen while the daily production rate of oil remained constant since 2005.

Figure 3: World Oil Market Demand and Supply Balance



Source: IEA, 2008.

Figure 3 shows the average global daily oil production and demand (measured in million barrels per day) in each year. The data show that oil production plateaued at about 84.5-85 million barrels per day in 2005. Starting in 2006, demand consistently rose over this level. With rising demand and constant supply, rising prices are needed to clear the market.

This basic analysis suggests that oil scarcity is a key fundamental driving high oil prices. Neoclassical economic theory argues that high prices driven by scarcity are not a strong justification for market intervention because market participants have proper incentives to address the situation. A sustained period of high prices will encourage consumers to reduce their consumption and producers will bring new supplies into the market. The nature of oil markets suggests this process may take time though. Demand is inelastic in the short run but over the long term consumers can reduce their demand by purchasing more efficient cars, moving closer to work, and taking alternative transportation (Dahl and Sterner, 1991; Puller and Greening, 1999; Graham and Glaister, 2002). However, consumers may need several months to many years to make these changes. On the supply side, projects that increase supplies of crude

oil, unconventional sources, and alternatives all take several years to over a decade to bring into the market. Therefore, the supply response to high prices is also over a long-term time horizon.

Renewable fuels could help address high oil prices by reducing demand for crude oil. However, with high prices caused by scarcity, the market already provides the needed price signals to induce renewable energy supplies, and this reason alone is not a strong justification for a renewable energy requirement. Consumers will buy renewable fuels if their costs are competitive with crude oil and other alternatives. These arguments do not suggest that the oil market is a model of perfect competition and without market failures. Economists actively debate the existence and size of several market failures in the oil market that could demand the attention of policymakers.

An important starting point is that the oil market is far from a textbook example of a perfectly competitive market. National oil companies (NOCs) and several large international oil companies (IOCs) dominate the industry. The NOCs actually dwarf the IOCs, like ExxonMobil. Table 1 shows the world's twenty largest oil companies ranked by reserves under control.

Table 1: Twenty Largest Oil Companies Ranked by 2006 Reserves

Rank	Company	Country	Petroleum Reserves (million barrels)
1	Saudi Arabian Oil Company*	Saudi Arabia	259,400
2	National Iranian Oil Company*	Iran	136,000
3	Iraq National Oil Company*	Iraq	115,000
4	Kuwait Petroleum Corporation*	Kuwait	99,000
5	Abu Dhabi National Oil Company*	UAE	92,200
6	Petroleos de Venezuela.S.A.*	Venezuela	80,120
7	National Oil Company*	Libya	41,464
8	Nigerian National Petroleum Corporation*	Nigeria	36,220
9	OAo Rosneft	Russia	15,963
10	OAo Lukoil	Russia	15,927
11	Qatar General Petroleum Corporation*	Qatar	15,207
12	Petroleos Mexicanos	Mexico	12,849
13	Sonatrach*	Algeria	12,270
14	PetroChina Co. Ltd.	China	11,618
15	Petroleo Brasileiro S.A.	Brazil	9,418
16	ExxonMobil	US	8,194
17	Sonangol*	Angola	8,000
18	Chevron	US	7,806
19	BP Corporation	US	5,893
20	Petronas	Malaysia	5,300

* denotes OPEC member

Source: *Oil & Gas Journal*, September 17, 2007

Table 1 ranks the companies by petroleum reserves and illustrates that the national oil companies control most of the world's reserves. The table shows that the top 5 NOCs control over 70% of the world's reserves. Most of these NOCs do not allow equity participation by foreign IOCs and their governments play a key role in the NOCs' decisions; however, the NOCs vary considerably in their size, competency, and relationship with their governments (Barnes and Chen, 2007). While firm output and market shares are the typical measures used to assess market power in an industry, the shares of reserves held by NOCs indicate these companies, and by extension their governments, have considerable long-term market power in the petroleum market. The potential for market power is not the only deviation from the textbook competitive model. The NOCs may have broader objectives than maximizing profits because of their close relationship with their governments. Finally, many of the NOCs are members of OPEC (denoted by the asterisks) with a collective goal of restricting output to increase prices.

Economists have vigorously debated OPEC's motivations and ability to coordinate its actions. Alhajji (2004) divides the competing views into a cartel models and competitive models. The researchers using cartel models assume OPEC (or some subset of OPEC) is an oligopoly that can coordinate output and raise prices above competitive levels. Other analysts find that cartel behavior is not a good explanation for observed market output and prices. They offer competitive models that better explain behavior. Griffin (1985) summarized the competing theories on OPEC behavior into four categories: cartel model, competitive model, target revenue model, and property rights model. Griffin notes several cartel models in the literature but all have OPEC members in a market-sharing cartel where the market shares vary through time. However, even with an organized cartel, a competitive model may explain market behavior better than a cartel model because cartel members always have incentives to cheat and increase their output. In sum, if considerable cheating within the cartel occurs then the market equilibrium will tend towards the competitive equilibrium. The target-revenue model argues that OPEC member countries have internal investment objectives they plan to meet through oil revenues. Once the country reaches these targets, they have no incentive to expand production. Furthermore, the country has constraints on how much revenue they can use given by country's ability to "absorb" investment. The property rights model argues that the change in oil asset ownership from oil concessions to national oil companies changed the discount rates applied to oil production. As international oil companies saw their impending loss of ownership, they applied high discount rates and increased production. After the assets switched to national

control, the governments applied lower discount rates and lowered production levels, which led to higher prices.

Griffin (1985) empirically tested these competing hypotheses and found the data best supported a cartel model. Griffin says, “Based on this evidence, OPEC appears to be a real cartel with at least partially effective output coordination (p.957).” Even though Griffin’s data set was limited to 1971-1983, more recent analyses have come to similar conclusions. Kaufman et al. (2004) uses a different econometric model that can better characterize the causal relationships between variables and finds that OPEC affects real oil prices through their decisions on capacity utilization, production quotas, and cheating behavior. Gately (2004) states that OPEC’s ability to coordinate pricing and output strategy among all members is limited. The literature on OPEC behavior is much more extensive than this discussion; however, for the purposes of this analysis this broad summary captures several of the relevant issues in analyzing a national renewable energy requirement. The first is that the empirical analysis in the economics literature indicates that OPEC members have measured ability to affect world oil prices through their decisions to limit output. In addition, OPEC’s ability to impact prices varies through time.

Assuming OPEC has some ability to coordinate its output among member countries and raise prices above the competitive equilibrium, large oil-consuming nations, such as the U.S., could pursue policies to reduce aggregate reductions in oil demand (such as a renewable energy requirement), which would lower the price of oil for all consumers in the nation (and world market). This effort to reduce aggregate demand would require government intervention because of free rider problems involved in getting individuals to reduce their consumption. Yet, if OPEC effectively functioned as a cartel, it would respond to this action by further constraining output to keep the price of oil above the competitive equilibrium. Therefore, the ultimate impact of a coordinated effort to reduce demand depends on how effectively OPEC can coordinate actions of member countries.

Irrespective of OPEC, the ability of large consumers to affect petroleum market prices through policies reducing petroleum demand is known as a monopsony effect and is another argument forwarded to support policies such as a renewable energy requirement. A 25% requirement to utilize biofuels would reduce world demand for oil by a non-trivial amount, and a resulting price decrease would benefit all U.S. oil consumers as well as consumers in the rest of the world. Again, the magnitude of the price change for a given change in demand depends on assumptions about how OPEC and other oil suppliers would respond as well as the amount of spare capacity in the market. The model and analysis described in Chapter 2 and the Technical

Appendix will show how I address these issues. In addition, a renewable energy requirement is not the only policy that could achieve this goal of reducing oil demand. Any policy that reduces aggregate demand for crude oil, such as improving fuel economy or developing unconventional petroleum sources, would have the same effect.

Another market failure studied by economists is the link between high oil prices and their negative effects on aggregate output at the macroeconomic level. This is a potential externality of high oil dependence because individual consumers would not account for the social costs of oil consumption in their individual consumption decisions. Hamilton (1983) noted that oil price spikes preceded seven of the eight recessions in the U.S. economy since WWII. His analysis did not rule out other factors for the recessions but showed a strong correlation between oil price spikes and recessions. Hamilton's work sparked a considerable amount of theoretical and empirical research investigating the macroeconomic impacts of oil price spikes. Several economists disputed the causal link between oil price spikes and decline in GDP.

One reason for the skepticism is that energy consumption is a small portion of the aggregate economy and therefore an increase in energy prices is unlikely to affect the entire economy. Bohi (1991) found that the link between oil price increases and output was not consistent across countries or sectors and argued that contractionary monetary policy spurred by oil price increases caused the recessions. Bernanke, Gertler, and Watson (1997) used an econometric technique to decompose the impact of oil prices and monetary policy on GDP and found that the decrease in output after oil price spikes is largely due to monetary policy. Bernanke, Gertler, and Watson's findings sparked a considerable debate in the literature and new research on alternative specifications of econometric models.

More recent analyses of the data focus on a fundamental flaw in Bernanke, Gertler, and Watson (1997), which is that their results violated the Lucas Critique (Hamilton and Herrera, 2004; Jones, Leiby, and Paik, 2004). Bernanke, Gertler, and Watson (1997) used their econometric results to simulate what would have happened to GDP after the oil price spikes if the Federal Reserve had maintained lower interest rates, but this mode of analysis ignores the fact that the estimated responses used in the econometric model were observed while market participants were behaving under one type of policy rule (that the Fed increases interest rates when oil prices increase) yet they simulate an environment where the Fed pursues the opposite policy. Jones, Leiby, and Paik (2004) observe that the current empirical evidence in the literature points towards an oil price-GDP elasticity near -0.055, but that debate still continues

on this relationship. Overall, the research indicates an externality of oil consumption on aggregate output but the magnitude still remains uncertain. Toman (1993) argues that these two market failures, monopsony effect and GDP-oil price linkage, comprise the “energy security” externality.

Another concept sometimes conflated with energy security is energy independence. The concerns about energy independence focus on the growth in foreign oil imports, which some argue makes the U.S. vulnerable to a cutoff in supply. With a global market for oil, the U.S. is not threatened with physical shortages of oil unless it creates them through a policy response. A foreign oil producer could decide to stop selling oil onto the market and if this was a large producer such as Iran or Saudi Arabia the price of oil could spike sharply. The U.S. would still have access to oil supplies from other producers but the price may be very high, become unpopular among consumers, and hurt economic growth. Note though, the damage occurs through the link between oil prices and GDP and not a physical shortage.

Most importantly, even if the U.S. could supply all of its oil demand domestically, it would still be vulnerable to the same price spike as long as global demand and supply are tight. For instance, if Saudi Arabia’s supplies were suddenly unavailable to the world market, then the price of oil would spike and the price of the oil produced in the U.S. would also rise to the world level. If the government tried to control domestic prices, then domestic oil producers would sell their supply to foreign consumers and domestic prices would still rise. The government could try to mitigate the price spike through subsidies but this policy could become very costly.

This discussion on energy independence applies to renewable energy because increasing renewable fuels, even to the 25% level, is unlikely eliminate the U.S. economy’s sensitivity to oil price volatility. Even with renewable fuels at the 25% level, petroleum-derived fuels will likely remain the marginal supply in the market and set the price of transportation fuels. Another interpretation is that even if the U.S. can produce extremely inexpensive cellulosic ethanol, the price of this fuel will rise to the price set in the market, which is the marginal cost of the marginal supply. This situation could potentially change if the nation could diversify into several alternatives, and especially if their costs were uncorrelated. If there was substantial penetration of renewable fuels, electricity, and another unconventional source like coal-to-liquids, then the price of transportation fuels may become less volatile. Nonetheless, these arguments do not imply that increasing the supply of renewable fuels would have no energy security benefits. The earlier discussion described how increasing renewable fuels could decrease oil prices and by diversifying the fuel supply the nation is less vulnerable to the

macroeconomic impacts of oil price spikes. The discussion on energy independence argues that the nation currently relies so heavily on oil consumption that no one policy measure, whether it is expanding domestic production of oil or renewables, is likely to have a large enough impact to eliminate the nation's vulnerability to oil price spikes.

Stimulating Economic Development

Renewable energy advocates frequently argue that policies promoting renewable energy development will enhance job opportunities, many of them high paying, by redirecting resources paid to foreign energy producers towards domestic renewable energy producers. Moreover, some advocates stress that these job opportunities will occur in regions that are enduring difficult economic prospects, such as rural communities and the manufacturing belt (Union of Concerned Scientists 2007; Renewable Energy Policy Project, 2002; Sterzinger and Svrcek, 2004, 2005; Renewable Fuels Association, 2008b). Critics of renewable energy requirements argue just the opposite. They argue that these policies will increase energy prices, which hurts energy consumers, harms U.S. competitiveness with countries that have lower energy prices, transfers wealth from regions that are scarce in renewable energy to regions with more abundant supplies, and reduces employment (Edison Electric Institute, 2008; Grocery Manufacturers Association, 2008; American Petroleum Institute, 2007). Both sides in the debate are technically correct because they generally focus on a subset of the total impacts from the policy.

As illustrated in Figure 1, the 25% renewable energy requirement would significantly increase renewable energy in electricity and especially motor vehicle transportation fuels relative to most current projections of the future. Therefore, reaching the 25% level in both markets is likely to increase significantly the labor and capital allocated to renewable energy, leading to considerable increases in renewable energy-related jobs. For instance, the Renewable Energy Policy Project (REPP) estimated that a 15% RPS in Nevada would lead to "creation"⁵ of over 27,000 jobs over a ten year period (REPP and Nevada AFL-CIO, 2002). These jobs would span many industries: manufacturing of wind turbine and solar panel parts, construction of renewable energy power plants, growing energy crops, construction and operation of biofuel refineries, and construction of electricity transmission lines to areas rich in renewable energy.

⁵ With a fixed labor supply in the short run, the policy change cannot create jobs but causes an increase in the demand for labor in the renewable energy industry. This labor demand is met by employing previously unemployed workers or by workers changing jobs. The policy also reduces demand for labor in the fossil fuel industries and the equilibrium level of employment declines in these markets.

As many of the advocates state, these jobs could occur in rural areas and regions that are currently losing their manufacturing base. However, there is no guarantee that these jobs would be based in the U.S.; Germany and Japan are currently leaders in wind and solar power technologies (in part due to their governments' strong support for these technologies) and could gain many of the employment benefits of the policy. Low-cost foreign manufacturers could produce many of the parts for renewable energy power plants. Lower-cost biomass feedstock could be imported into the U.S. The renewable energy industry is a global industry and a significant increase in renewable energy by a large energy consumer like the U.S. would have employment implications through the entire global supply chain.

Likewise, the fossil fuel industry has a global supply chain and a significant reduction in fossil fuel demand caused by renewable energy requirements in the U.S. would decrease the demand for labor and capital employed by this industry in locations throughout the supply chain. This would reduce resources from U.S. consumers spent on production in foreign countries but may also affect the U.S.-based labor involved in delivering fossil fuel energy to the U.S. market. Many of these jobs are also high-paying jobs, as noted by the critics, and many of the jobs are also located in economically depressed areas, like coal-mining regions of Appalachia. Therefore, increasing renewable energy use in the U.S. and decreasing fossil fuel use means allocating more labor and capital on renewable energy and less on fossil fuels in the global supply chains of both of these industries. The net balance of jobs in particular locations in the U.S. and abroad depends on a complicated mix of factors, which becomes even more complex when considering the effects of the policy on consumers.

The impact of the policy on consumers is multi-faceted. As energy prices rise, energy consumers reduce their consumption of energy, which has labor and economic effects on energy producers. Consumers may also change their consumption of other goods. As energy prices increase while holding consumers' incomes constant, consumers pay more for energy and typically reduce their consumption of energy and other goods. This decline in consumption for other consumer goods also could negatively affect the labor demanded to produce these goods and the profitability of firms producing them. In addition, energy consumers are a broad category that encompasses more than end-use consumers, like a homeowner or car owner. Energy is an input to many forms of production. Therefore, large industrial customers and small businesses are affected by energy price increases. On the margin, increases in the price of one of their inputs to production, reduces profits, and may force some firms out of business.

Furthermore, increases in the demand for renewable energy may spur price increases in other markets, indicated by the concern of the Grocery Manufacturers Association for a Renewable Fuels Standard. Recent increases in ethanol production have played a role in rising corn prices. The price of corn increased as the share of the corn crop going into ethanol production increased from 15% in 2006 to 19% in 2007 (USDA, 2008). The food industry is concerned about these price increases because corn is an important ingredient for feeding livestock and producing many other food items. This is only one example; however, similar impacts in other markets are conceivable. Substantial increases in the demand for biomass may affect the price of land, which is an input to production for many other products. Similarly, a boom in building renewable energy power plants and refineries may increase the costs of raw materials and engineering expertise.

As the discussion above notes, the policy could have significant effects on the distribution of energy market benefits between renewable energy producers, fossil fuel producers, and energy consumers. Most of the arguments forwarded by both sides focus on these distributional effects of the policy, and the politics behind renewable energy requirement proposals are also driven by these distributional impacts. The potential effects on allocative efficiency are also significant. This analysis will focus on the impacts to economic efficiency but also present results relevant to the distributional issues from the policy requirement.

Enhancing Foreign Policy Flexibility

In a recent independent task force report on national security and U.S. oil dependency, the Council on Foreign Relations concluded that oil dependence affected U.S. foreign policy in six ways (Deutch and Schlesinger, 2006). The first impact is that enormous oil revenues allow oil-exporting countries to act in opposition to U.S. interests and values. A second reason is that oil dependence results in political realignments that affect how the U.S. can work with other countries to achieve common interests. The third effect is that high prices and scarcity create fears that the current system of open markets can secure oil supplies. The fourth reason is that oil and gas revenues can undermine local governance. The fifth impact is that interruptions in oil supply can have significant political and economic consequences in the U.S. and other oil-importing countries. The final effect is that some analysts find a strong link between U.S. oil dependence and military deployments in the Persian Gulf.

On the first impact, there is no question large oil-exporting nations earn enormous revenues under current prices. Saudi Arabia and Russia lead all oil exporters with more than double the exports of any other nations. Saudi Arabia exported 8.5 million barrels per day

(mb/d) of oil in 2006 and Russia exported 6.9 mb/d. The top fifteen oil-exporting countries all exported more than 1 mb/d in 2006, which translates into gross revenues in excess of \$50 billion per year when assuming prices of \$100 per barrel of oil (EIA, 2008d). Deutch and Schlesinger (2006) cite Iran's nuclear weapons program, Russia's increasing tendencies towards authoritarianism, and Venezuela's anti-U.S. policies in South America as examples of oil-exporting countries emboldened by rising oil revenues. Of note, large oil-export revenues do not necessarily always harm U.S. foreign policy interests. Both Mexico and Norway are within the top 10 oil-exporting nations and they are strong allies of the U.S. Increasing oil revenues can serve U.S. interests in these countries by contributing to their economic growth.

In the second effect, the Council cites how China's moves to secure oil supplies in Saudi Arabia, Iran, Nigeria, and Sudan as well as the European Union's energy dependence on Russia creates problems in gaining Chinese or European support on issues of common interest. Chinese oil interests in Sudan have severely compromised efforts to resolve violence in the country. European dependence on Russian and Iranian energy supplies has also limited their role in confronting Iran about their nuclear weapons program.

Relating to the previous point, oil-consuming countries have established direct relationships with several oil-producing nations because of concerns about supply security. Relying on these relationships instead of open markets exacerbates the problems noted above on gaining support for U.S. foreign policy interests. The Council again cites China's moves to secure direct supply relationships in Africa and the Middle East.

On the fourth issue, the Council argues that oil revenues can undermine good governance and the U.S. has foreign policy interests in promoting democratic accountability, low corruption, and fiscal transparency. These are the three elements the Council attributes with good governance. The Council argues that totalitarian governments can use oil revenues to entrench their rule and notes Nigeria as an example where oil revenues are undermining good governance.

As another concern, the Council states that a significant oil supply interruption would cause adverse economic and political consequences as the country tries to restore normal conditions. The U.S. would need a concerted diplomatic effort to coordinate efforts with other large oil-importing nations and oil-exporting nations. The Council notes that part of these efforts would be hurried, ineffectual, and possibly counterproductive because of the severe consequences from a supply interruption.

The final effect noted by the Council is the link between U.S. oil dependence and the defense budget. Some analysts have argued reducing U.S. oil dependence would allow the U.S. to redeploy military forces from the Persian Gulf to other regions and/or decrease military expenditures. The Council argues against this effect. They state that the U.S. has broader interests in the region beyond protecting the supply of oil and the U.S. would still deploy troops in the Persian Gulf to promote these interests. Another critique is that military deployments are primarily a fixed cost and are unlikely to change in response to a marginal change in oil consumption. Unless the U.S. could reduce its oil dependence to very low levels, maintaining the flow of oil in the Persian Gulf will remain an important national interest.

The critique on whether a marginal change in oil consumption could affect military deployments applies to all of the foreign policy concerns discussed above. Most policies to reduce oil consumption can only marginally change consumption and would not eliminate the nation's dependence on oil in the near term. The renewable energy requirement considered in this analysis fits this description. A marginal change in consumption would have some effect on several of the concerns. Reducing U.S. oil consumption would lower the world oil price marginally, which would reduce oil revenues earned by oil exporters (assuming OPEC has limited capacity to coordinate output). Yet, as long as major oil consumers remain committed to oil as a major energy source, oil exporters will earn significant revenues. Furthermore, oil revenues do not appear to cause many of the issues discussed by the Council, but do exacerbate the problems. Many of the issues related to governance (accountability, transparency, corruption, etc.) are underlying causal problems in countries like Sudan and Nigeria. Oil revenues can exacerbate the problem, but a marginal change in oil revenues is unlikely to solve the underlying governance issues. Countries acting in opposition to U.S. interests are also unlikely to change their behavior with a marginal change in their revenues; however, they will have fewer resources to pursue all of the government's objectives. For instance, both Iran and Venezuela spend considerable resources subsidizing energy prices for domestic consumers. With lower oil revenues, they will face more difficult choices in pursuing all of the government's objectives.

Finally, several of the Council's concerns involved the effects of other large oil consumers, notably China but also Western Europe, on U.S. foreign policy interests. A unilateral decrease in oil consumption that reduces oil prices may actually marginally increase oil dependence by these consumers. Yet, if a renewable energy requirement does result in the technological breakthroughs and cost reductions that make biofuels competitive with

petroleum-based fuels, then these countries may also substitute greater amounts of biofuels for oil.

Summary of Discussion on Policy Objectives

This discussion of the key policy issues animating the debate on renewable energy requirements reviewed the major arguments from advocates and critics. The discussion showed that greenhouse gas emissions are a clear externality associated with consumption of fossil fuels, and these emissions could create significant risks for future generations. Yet, the magnitude and distribution of these risks remains highly uncertain. Renewable energy sources can reduce GHG emissions, but with the caveat that the carbon-reduction potential of renewable energy sources can vary considerably, including some that can increase emissions relative to the fossil fuels they displace.

Many advocates claim that a significant national commitment to renewable energy, like a 25% requirement, would attract investment and technical expertise to these technologies on an unprecedented scale, and this attention would lead to the cost reductions and technological breakthroughs that would make renewable energy technologies competitive with fossil fuels. Review of the literature on technological change and policy-induced innovation showed that the process of invention and innovation competes for scarce resources within firms and policies that change the relative prices and profitability of R&D can stimulate innovation. Furthermore, the literature shows several market failures may lead to underinvestment in R&D and new technologies. These include the inability of private firms to appropriate all of the social benefits of new technologies and cost reductions that occur through learning-by-doing. Another strand of the literature argues that firms may not have realized all of the profitable opportunities of new technologies because of bounded rationality. A significant policy change, such as a renewable energy requirement, can force firms to focus attention on new technologies, which may result in significant technological breakthroughs.

The literature generally agrees that many of these benefits and market failures are real (Jaffe, Newell, and Stavins, 2003). The literature cites examples of policy-induced technological breakthroughs but there is no guarantee they would occur with a renewables requirement. Furthermore, even with cost reductions that occur with the significant expansion of renewable energy, the technologies could still remain expensive if initial costs of commercialization are much higher than expected or fossil fuel prices decline. Finally, renewables are not the only technologies that can reduce greenhouse gas emissions and oil consumption. The benefits of

reducing the costs of renewables must be balanced against the opportunity costs of not using the same political and economic resources to invest in other alternatives.

Renewable energy advocates also argue that renewable energy requirements can stimulate economic development and create new jobs in rural areas and regions with a declining manufacturing base. Critics of this policy contend the opposite will occur. The discussion on overall economic impacts described that the policy would likely cause significant shifts in the distribution of benefits between fossil fuel producers, renewable energy producers, and consumers. Fossil fuel producers would lose a portion of profits to renewable energy producers. Energy consumers would lose consumer surplus to both fossil fuel and renewable energy producers. The policy would also create dead weight losses as the price of energy (and related goods) increases. The overall economic efficiency of the policy compares the loss of consumer and producer surplus to the benefits; however, the political landscape for this policy is shaped the relative changes in the distribution of the benefits and the political influence of the affected interest groups.

The literature on oil consumption and energy security is complex and spans several disciplines. This discussion focused on several of the key elements and how they relate to a renewable energy requirement. The economics literature focuses on two externalities from oil consumption: the ability of large oil consumers to affect market prices through a policy to reduce aggregate demand for crude oil (the monopsony effect) and the impact of high oil prices on aggregate economic output. These are both effects that individual consumers would not take into account in their consumption. There is debate in the literature on the magnitude of these effects but the estimates are generally not large, especially in comparison to the recent increases in the price of crude oil.

Oil consumption potentially has other costs to the nation. Oil consumption at today's high prices transfers significant amounts of wealth from energy consumers to oil-producing nations. This can be a national concern because many oil-producing nations nationalized their oil industry and this wealth is used to pursue their governments' objectives. Several of these oil-producing nations are using this wealth in ways that can harm U.S. interests; however, the opposite is also occurring. Many oil-producers are using their wealth to invest in public goods that benefit their population and may also benefit the U.S. Other oil-consuming nations' relationships with oil producers have impaired U.S. foreign policy efforts to resolve violence in Sudan and stop Iran's nuclear weapons program. Finally, some analysts argue that significantly decreasing oil consumption would allow the military to reduce its presence in the Middle East.

This argument is more uncertain as the U.S. has other strategic interests in the region in addition to securing oil flow. Reducing oil consumption may allow the military to focus more on other interests in the region but it's unlikely to lead to a complete withdrawal from the region.

The critical issue in analyzing how renewable energy can mitigate external impacts of oil consumption is how a significant increase in renewable energy (and resulting decrease in oil consumption) affects the world price of oil. By reducing oil demand and diversifying its energy supply (particularly for transportation), the U.S. can decrease the price of oil and reduce some of the economy's vulnerability to high prices. Lower prices would benefit U.S. (and other) oil consumers and reduce wealth spent on oil imports.

Of note, these effects do not depend on whether renewable energy displaces domestic or imported oil because the influence of the policy is mediated through changes in the world price of oil. However, the distributional outcome of the policy and political support could vary depending on which sources change at the margin. Furthermore, other policies that reduce U.S. demand for crude oil could achieve the same goals, including greater efficiency standards, an oil tax, or an increase in domestic unconventional sources. Increases in domestic crude oil production could achieve some but not all of these goals. Increasing domestic supplies would lower the world oil price and achieve the goals related to the price; however, this policy would not reduce U.S. vulnerability to oil price spikes. Reducing this vulnerability requires diversification away from crude oil supplies.

Critics of renewable energy requirements contend that the policy could sharply raise energy prices, lower employment, and economic growth. They also argue that such large changes to complicated systems invariably result in unintended consequences. An important point is that policy makers need to distinguish between the policy's effects on economic efficiency and distribution of benefits in energy markets. Traditional economic analysis focuses on the policy's costs to economic efficiency. Assuming that renewable energy at the 25% level costs more than fossil fuels, which is an assumption this analysis makes, the policy requirement will cost society additional capital and labor to produce renewable energy plus the deadweight losses that occur as energy prices rise and decrease consumption. This analysis will quantify these effects, and decision makers need to weigh them relative to the benefits. Many of the costs cited by the critics, however, are distributional costs to particular industries. As will be shown in the analysis in Chapters 3 and 4, as renewable energy displaces fossil fuels, the prices of oil, coal, and natural gas decline and these producers lose surplus to energy consumers. These are real

losses in profits of fossil fuel producers but gains for energy consumers and renewable energy producers. This analysis also quantifies these effects and will show they are large.

The key issue with this policy requirement is the size of these effects is deeply uncertain because future energy markets are inherently uncertain, and most importantly the costs of renewable energy at the 25% level in 2025 are unknown to decision makers today. This analysis will apply new methods in uncertainty analysis to characterize the conditions where this policy requirement can reach 25% renewable energy at low cost to society, and also quantify the conditions when the policy becomes very costly. It will also analyze several policy options that can potentially hedge against the situations leading to costly outcomes.

Current Policies Supporting Renewable Energy

The federal government and many states currently have renewable energy requirements in place. Twenty seven states have RPS policies that require a certain percentage of electricity from renewable energy sources⁶. The U.S. Congress recently considered a 15% RPS by 2020, but this measure did not pass. Similar requirements exist for motor vehicle transportation fuels also. The U.S. Energy Policy Act of 2005 included a RFS requiring refiners to blend 7.5 billion gallons of ethanol and biodiesel into the nation's fuel supply by 2012, and recent legislation increased this requirement to 36 billion gallons by 2022. States also mandate renewable fuel use. In California, Governor Schwarzenegger established a low-carbon fuel standard in 2007 requiring carbon intensity of transportation fuels to decline 10% by 2020.

The U.S. also supports renewable energy with numerous other policies. The federal government offers investment and production tax credits for renewable energy. The production tax credit will expire at the end of 2008 and Congress is debating an extension. Many state governments offer additional tax incentives encouraging renewable energy production. Both federal and state levels of government have green power purchasing goals. The federal government supports renewable energy development through federal research programs, and has a program giving grants, loans, and loan guarantees to small biofuels producers. Similar programs exist in several states to encourage infrastructure development for biofuels.

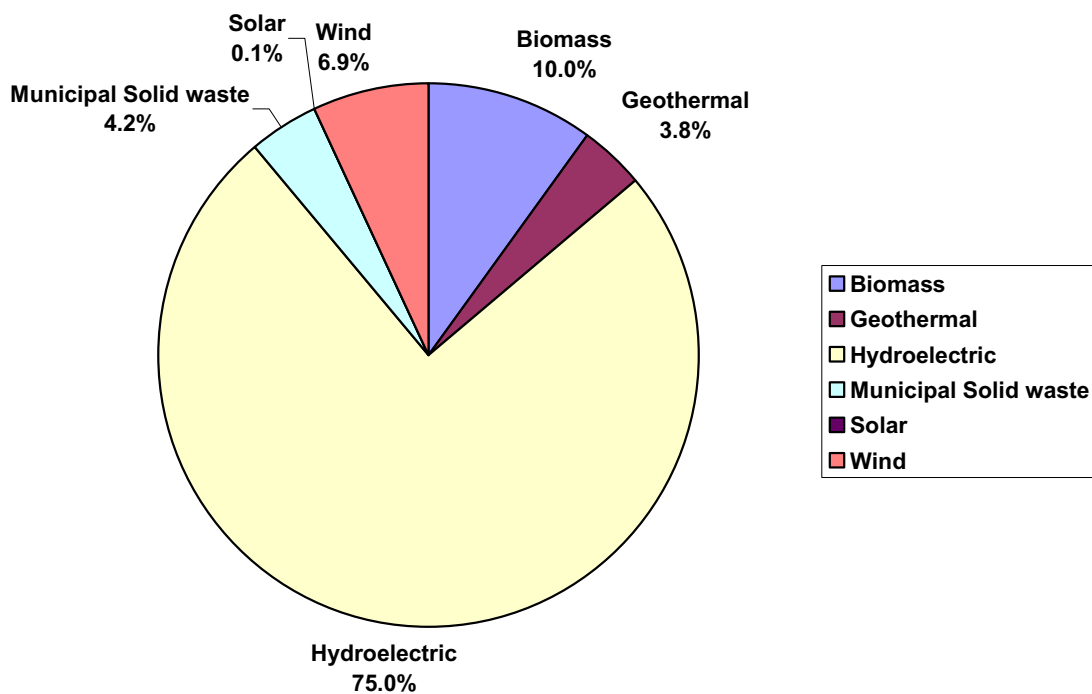
⁶ For a map of states with RPS see www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

RENEWABLE ELECTRICITY TECHNOLOGIES

This section discusses current use of renewable electricity technologies in the United States and other countries. It describes the technologies currently used and some of the technologies under development which may reach a commercial state in the timeframe of this policy. It also summarizes the key benefits and drawbacks of each technology. Before discussing the individual technologies, I provide an overview of the current state of renewable electricity in the U.S.

Figure 4 shows the current mix of renewable electricity production in the United States.

Figure 4: U.S. Renewable Electricity Generation in 2006



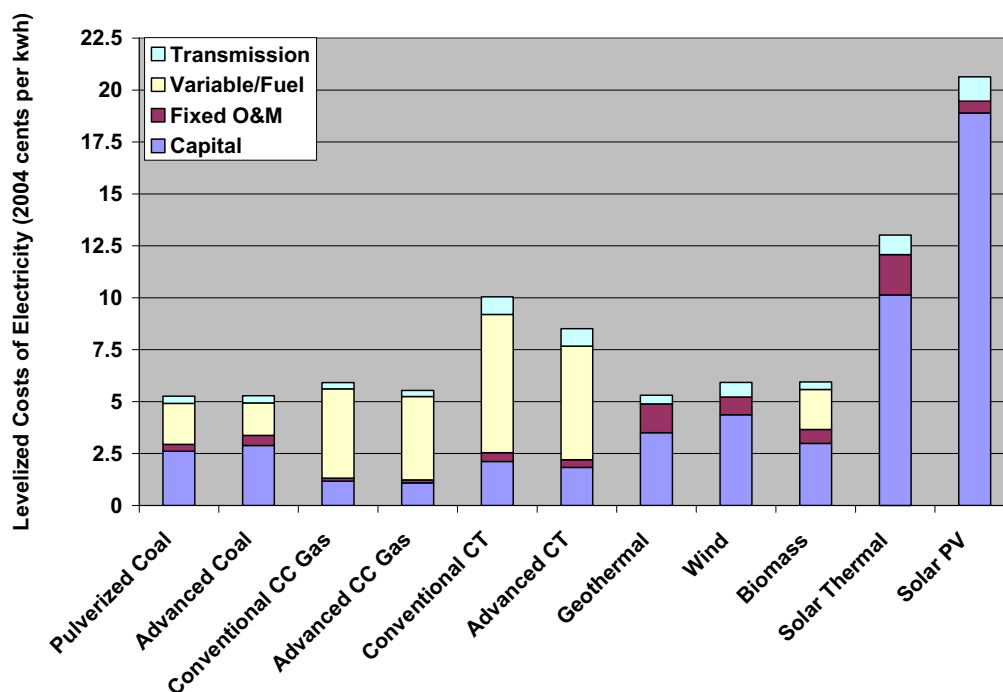
Source: EIA, 2006b

Total renewable power generation in 2006 was 385.7 billion kwh. As noted in Figure 1, this total was approximately 10% of U.S. generation. As Figure 4 shows, three quarters of that electricity

came from hydroelectric power. Biomass power made up the next largest proportion (10%) followed by wind (6.9%). Municipal solid waste and geothermal comprise similar fractions near 4% and solar power accounts for less than 1%.

Figure 5 shows estimates of 2020 electricity power plant costs from the AEO 2006.

Figure 5: EIA Estimates of 2020 Electricity Costs



Source: EIA, 2006a; Beamon, 2007a.

The figure shows cost estimates for the levelized costs of electricity⁷ (LCOE) for new power plants in 2020. I use estimated 2020 costs as a baseline because power plant construction would need to begin near this date to finish and come online by 2025. The first four columns are estimates of baseload power from coal and natural gas fueled plants. EIA projects power from these plants will cost between 5-6 cents per kwh in 2020. The next two estimates are for peak period electricity from gas-fueled combustion turbines. These power sources are projected to cost between 8-10 cents per kwh.

⁷ The levelized cost of electricity (LCOE) is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation) (from EIA Energy Glossary – see www.eia.doe.gov/glossary/glossary_1.htm).

The next five estimates show EIA's projections for renewable electricity costs in 2020. EIA's projections show that geothermal, wind, and biomass cost more than the baseload sources but the differences are less than 1 cent per kwh. Both solar technologies are more expensive. EIA projects solar thermal costs near 13 cents per kwh and solar pv over 20 cents per kwh. The relatively higher costs for renewables relative to fossil fuel sources explains the current limited amounts used in the electricity mix (McVeigh, 1999). The graph shows that the difference between some technologies is small and these projections also assume no future climate policy and lower energy prices than current levels.

The EIA has revised these projections in subsequent reports and this analysis will vary the renewable energy cost assumptions considerably. In EIA's recent revisions, the costs of fossil fuels increased and the capital costs of all power plants increased due to higher costs for raw materials and engineering labor costs. With these revisions, renewables gained an increasing share of the energy market but was still limited (shown in Figure 1). Even with the revised projections, a 25% requirement would still considerably increase the amount of renewable energy in the system. A final note is that the renewable electricity price projections shown in Figure 5 assume limited levels of renewables and do not reflect cost increases that occur as capacity increases. Costs of renewables increase as capacity rises because the high-quality, low-cost sites are used initially, which leads to higher costs for additional capacity. This potential for higher costs can be offset by technological improvements that lower the capital costs of the plant and improve the ability to utilize marginal sites. The net of these two factors, cost escalation with additional capacity and cost decreases with learning, drive the future technology costs, and remain deeply uncertain. The remainder of this section now describes each of the technologies in greater detail.

Wind Power

Wind power is currently growing at approximately 30% per year and is the fastest growing power source in the world. Globally, over 20 GW of new capacity came online in 2007, which increased the world's total combined capacity to 94 GW (GWEC, 2008). The United States added 5,244 MW of new capacity in 2007, which accounted for nearly 30% of new capacity installed in that year. The U.S. total wind capacity now stands at 16,818 MW (AWEA, 2008). While wind power is growing quickly, it still remains a small portion of the total electricity power plant capacity. Total U.S. power plant capacity in 2006 stood at 1,076 GW, and wind power comprised just over 1% of the total (EIA, 2006c).

Current utility-scale wind power plants consist of wind turbines that stand on an 80-meter tower with rotors that are 40 meters long. Wind turbines with this configuration have a rated capacity between 1.5 and 2 MW (AWEA, 2004). EIA estimates that the average size of a wind power plant is 50 MW, which consists of approximately 25-30 individual turbines. Smaller wind turbines are available for use on residences and farms. These turbines stand on 40-meter towers with 4-meter rotors. Offshore wind turbines are used in Europe but remain controversial in the United States. Offshore sites usually use larger towers and rotors increasing their efficiency. Wind is also more consistent in many offshore areas, which makes them desirable sites.

Wind power's current popularity is driven by its low cost relative to other renewable energy sources. The EIA estimates the capital cost of a wind turbine at \$1150 per kw with levelized costs of electricity at 5.8 cents per kwh (EIA, 2006a). When compared to the cost of other renewable electricity sources, wind power is one of the lowest-cost power sources in many portions of the country.

A key advantage of wind power is low pollution emissions. Operation of the wind turbine involves no emissions but some occur in producing the turbine and building the site. Over the entire lifecycle, wind power has very low emissions compared to other power sources (Meier, 2005).

Another advantage of wind power is low price volatility. Figure 5 shows that variable costs comprise a negligible portion of the costs of wind power. In contrast, fuel costs are the majority of costs in natural gas fueled plants and natural gas prices can be highly volatile. Essentially, after constructing a wind power plant the cost of electricity is known and relatively constant through time, but does depend on future wind patterns. Wind power can also benefit rural farmers. Many wind power projects rent land from farmers with limited impact on their operations. This provides an additional source of income for the farmer.

One of the key disadvantages of wind power is its variable output, which is known as intermittency. Electricity generation varies with the wind speeds. At low wind speeds, the turbine is often producing power below its rated capacity. Recent estimates show that the capacity factors⁸ for wind turbines vary from 0.25-0.4, which means the turbines produce between 25%-40% of their potential maximum output. This does not mean the turbines only produce electricity 25%-40% of the time. The turbines produce power when the wind blows, but their output is below maximum capacity during a large portion of their operation.

⁸ The capacity factor is the ratio of the actual power output to the maximum potential output.

Balancing the variable output is one of the challenges of intermittent power sources. Any fluctuations in output from wind power need to be met by other power sources. At low levels of wind power capacity, this does not present many problems. However, as the amount of wind power in the system increases, system reliability is a concern. Recent research has analyzed the costs of integrating large amounts of wind power into the electricity grid, and found that wind power variability could increase the costs of wind power by 1-2 cents per kwh (Decarolis and Keith, 2006). The researchers also found that the costs increase as the amount of wind power in the system rises. A related issue is that a large increase in wind power capacity will require expanding the transmission grid to remote areas with high quality wind resources. These expansions will require obtaining permits from multiple levels of government and overcoming potential challenges from landowners that may object to these infrastructure projects in rural areas. This analysis treats these investment costs in new transmission capacity as one of the uncertainties in the costs of wind power as capacity of this resource expands.

Environmental and aesthetic concerns are another disadvantage of wind power. Wind turbines can pose a problem for migratory birds. Construction of wind turbines in the 1980's in the Altamont Pass outside of San Francisco led to a significant number of golden eagle and red-tailed hawk deaths. Current wind turbine designs are larger, rotate slower, and pose less risk for bird populations. Nevertheless, a substantial increase in wind power, which would occur under a 25% requirement, would raise risks for migratory birds and impact their habitat. Aesthetic concerns have also been a problem with wind power projects. In many areas, most recently in the Nantucket Sound, residents object to wind power projects because of concerns about the visual impact of the turbines. As noted above, a large number of turbines are required to make the wind plant economical and the turbines are often placed in prominent locations with high quality wind resources. Because of these concerns, some quality wind power sites may not be acceptable to the public.

Biomass Power

Biomass-fueled electricity is currently the largest nonhydroelectric renewable energy source in the United States. In 2006, biomass provided 38.6 billion kwh of electricity which was 40% of the nonhydroelectric renewable energy produced (EIA, 2006c). The forestry industry is currently the largest producer and consumer of biomass electricity. Lumber, pulp, and paper mills are using forestry wastes to create electricity and heat. Forest wastes are not the only potential source of biomass though. Agricultural and urban wastes can also be used to produce

electricity as well as energy crops. Two leading candidates for energy crops are fast-growing native grasses such as switchgrass and short-rotation tree crops, such as poplar and willow trees.

Most biomass electricity is produced by directly burning the fuel to create steam that drives an electric power turbine. In many cases, the heat from the steam is also used for industrial processes. Current biomass electricity plants are generally 20-50 MW, which is a small size for a power plant that produces baseload power. At this size, biomass electricity lacks the economies of scale of coal plants that use a similar combustion process and range from 100-1,000 MW.

Alternatives to direct combustion are available but not in commercial use today. Biomass can be heated and pressurized to produce a gas in a process known as “gasification”. The electricity producer can clean the gas more easily and then use it in a combined-cycle power plant. The combined-cycle plant uses the gas to fuel a gas turbine that produces electricity. The exhaust heat from the turbine then produces additional electricity in a traditional steam cycle. This entire process is known as an integrated-gasification combined-cycle (IGCC) power plant. Combined-cycle power plants achieve efficiencies between 40%-60%; whereas, power plants directly burning biomass have efficiencies in the 20% range.

Key advantages of biomass electricity are reductions in pollutant emissions, firm power supply, domestic resource base, and stimulating rural development. Burning biomass releases carbon dioxide but growing the biomass absorbs the greenhouse gas from the atmosphere. The net emissions over the lifecycle then depend on the emissions during the cultivation of biomass, transportation to the plant, and building the plant. Recent estimates show that biomass electricity can significantly reduce greenhouse gas emissions relative to similar coal and natural gas powered plants (Meier et. al., 2005). However, an important consideration is any potential land use changes that occur to grow biomass. If the biomass displaces crops and requires clearing new land, then biomass can have a negative impact. Overall, the net greenhouse gas emission impacts are sensitive to how the biomass feedstock is produced.

Biomass electricity plants produce electricity that can be dispatched by a system operator and provide baseload power. This is an important benefit when many of the renewable electricity sources provide intermittent power. Another advantage is that biomass power plants use the same general technologies employed in coal power plants (both direct combustion and IGCC) and can benefit from technological advances in the coal industry. Biomass feedstock can be grown domestically and is less vulnerable to potential supply disruptions but would be

vulnerable to variations in local climate. Finally, biomass electricity production would provide new markets for waste products and new opportunities for farmers to grow energy crops. Both effects would stimulate rural economies and enhance land values for farmers.

A primary disadvantage of biomass electricity is cost. As Figure 5 showed, EIA projects the costs of electricity produced through biomass gasification at approximately 6 cents per kwh (the EIA assumes biomass power uses IGCC technology). Of note, this estimate assumes relatively inexpensive biomass feedstock. As will be shown in Chapters 3 and 4, a 25 x 25 policy substantially drives up the demand for biomass feedstock and resulting price. In many scenarios, biomass electricity costs between 8-9 cents per kwh, which results in costs about 3-4 cents per kwh greater than coal plants and 1-2 cents per kwh greater than natural gas fueled plants. The analysis also involves scenarios with higher costs for biomass power.

As discussed above, biomass power plants are smaller size and lack the economies of scale of larger coal plants. Increasing the size of the plant would improve the economies of scale of the plant; however, the biomass feedstock delivery costs increase. The plants are sized to the supply of biomass that can be cost-effectively delivered to the plant. Increasing the plant size would typically require more biomass to be delivered from further distances, and research on ethanol plants shows that feedstock delivery costs increase nonlinearly with transportation distance (Aden et al., 2002). Therefore, substantially improving the non-feedstock costs by increasing the size of the plant without increasing feedstock costs is challenging.

A second issue with biomass power plants is the potential land use changes and environmental impacts of dedicated energy crops. Many potential feedstocks are available for power production, including waste products; however, use of biomass power at a large scale may induce land owners to convert their land to growing energy crops. Depending on the farmer's practices and crops grown, the environmental impacts may be limited to severe. Recent research has shown that land use conversion for the production of corn-based ethanol can actually increase greenhouse gas emissions. Under certain situations, similar results could occur for biomass produced for electricity (Searchinger et al., 2008; Fargione et al., 2008). Another concern is the impacts of biomass crops on drinking water supplies and water pollution. Excessive irrigation requirements could increase stress on water supplies in many regions. Greater use of fertilizer and pesticides could also exacerbate runoff pollution problems, which are already a serious problem in many agricultural communities.

Biomass Cofiring

The previous section discussed the problem of high capital costs and limited economies of scale with dedicated biomass power plants. An alternative to reduce capital expenditures is adding biomass into the fuel mix at existing coal plants, which is known as biomass cofiring. Coal plants can add biomass in a mix of 5% up to 15%. Mixing fuels requires some capital investment to add biomass into the fuel supply and modify the power plant boiler; however, these capital investments are much less than the cost of building a dedicated biomass plant. Biomass feedstock costs are still higher on average than coal costs and currently biomass cofiring is used in limited applications.

Reducing the capital costs of substituting biomass for coal is the primary advantage of cofiring relative to other renewable energy sources. When biomass feedstocks are available at low cost, cofiring can be a cost-effective method to reduce greenhouse gas emissions from a coal-fired power plant.

The drawbacks include limited access to low-cost biomass supplies at many coal power plants and additional operating costs of adding biomass into the plant boiler. For coal power plants in the Rocky Mountain region, which is a substantial portion of the nation's coal capacity, biomass supplies are not locally available. By contrast, in the Midwest and Southeast where there is also a large capacity of coal plants, biomass supplies are potentially more abundant (Robinson et. al., 2003). Finally, adding biomass cofiring can cause some operational difficulties in the power plant boiler as biomass has higher moisture content than coal.

Geothermal

Geothermal power refers to electricity produced using heat from underground sources. Analysis of underground heat flow shows that an enormous amount of energy is available in the United States—equivalent to 130,000 times current national energy consumption (MIT, 2006). However, most of this heat occurs at depths that are uneconomical to utilize with today's technology. New geothermal technologies to tap these energy sources are under development and could become competitive in the future.

In 2006, geothermal sources produced 15% of the nonhydroelectric renewable electricity in the United States (EIA, 2007c). Nearly all of this electricity was produced in areas of the Western U.S. with suitable geology for the geothermal technologies used today.

Underground heat sources generally come from two sources: volcanic activity and radioactive decay. In areas where magma exists near the surface, it heats rocks and water

underground. These areas are known as hydrothermal vents and geothermal plants can use the heated water to create steam and electricity. Most geothermal plants today operate on this principle, but hydrothermal vents only exist in a limited number of places, primarily in the Western U.S. Other sources of geothermal heat can be used though. The heat flow in underground rocks increases at lower depths below the surface. New geothermal technologies propose to drill wells deep below the surface (from several km up to 10 km) and “mine” the heat. These systems, known as enhanced geothermal systems (EGS), drill two wells and fracture the rocks between them. Water is pumped into one well, absorbs heat while migrating between wells, and is extracted from the other. These systems are not in commercial use today but the wells use drilling technologies developed by the oil and gas industry, which have improved substantially in recent years. If EGS technologies can become competitive, a substantial amount of energy is available, and deep geothermal energy sources are also more dispersed throughout the country.

Geothermal power’s principal advantages are the limited pollutant emissions and reliable electricity that can be used as a baseload power source. Geothermal power produces limited greenhouse gas emissions over the entire lifecycle. The main emissions occur during construction of the power plant and its components. Geothermal power can be dispatched by the plant operator to provide firm power, as opposed to intermittent sources such as solar and wind. As a firm power source, it can directly substitute for other firm power sources such as coal and combined cycle natural gas.

A key disadvantage of geothermal power is that with current technologies it is only available in limited locations. Most of the remaining potential sites using existing technology with hydrothermal vents are located in the Rocky Mountain and Pacific Coastal states. Many of these potential sites are remote and distant from existing power lines. Furthermore, many of these sites may be controversial to develop because they are located in rural areas. There are also concerns with water use and waste disposal at geothermal power plants. Some of the water wells draw up toxic substances that need proper disposal. The systems may also need local water supplies to inject into their wells, which can stress existing water supplies. Finally, an additional risk with heat mining is that fracturing the rock formations between wells may induce seismic activity.

Solar

Solar power converts energy from the sun into electricity. Photovoltaic panels and solar thermal plants are the two solar technologies most commonly used to produce electricity today. Photovoltaic arrays directly convert sunlight into electricity. The arrays consist of multiple modules connected together that are positioned to receive sunlight. The arrays are often located on building rooftops, but with new materials advances the photovoltaic cells can be integrated directly into building materials. Solar thermal plants use mirrors and tracking systems to focus sunlight on a fluid. This fluid is heated to high temperatures and the heat is then used to generate electricity. These systems are also called concentrating solar power.

In 2006, solar power provided 0.51 billion kwh of electricity in the United States. This was 0.5% of nonhydroelectric renewable electricity generated in the United States (EIA, 2006b). Solar energy is a small percentage of the total but growing quickly. Worldwide, solar pv growth ranged from 40%-50% in recent years (IEA, 2006). Germany and Japan lead the world in installed capacity of solar pv and the U.S. follows behind these countries (IEA, 2006).

The main advantages of solar power are its low emissions, constant costs, and coincidence with peak demand. Solar power results in some emissions during the production of the pv modules and concentrating plants. Generating electricity from solar power causes no emissions though. Capital costs comprise nearly all the cost of solar power; therefore, once a plant is built its costs remain relatively constant over its lifetime. Finally, solar energy output varies through the day with a peak in the afternoon, which matches electricity peak demand closely in many locations. This means solar power can substitute for power from peaking plants, which are typically the most expensive power sources.

The cost of solar energy is a key disadvantage. Solar power is also intermittent and does not provide power at night; however, CSP has the ability to store energy for up to six hours, which mitigates some of the intermittency problem for this technology. Solar pv modules use some toxic materials in construction, which presents problems in handling and eventual disposal of the materials. Finally, not all locations are well-suited for solar energy installations. Even in areas with ample sunlight, mountains and buildings can block sunlight during certain portions of the day. Furthermore, many of the locations with suitable solar power potential are located far from existing transmission lines and would require potentially expensive investments in the transmission grid to connect the sites.

The current cost of pv modules is estimated at 25-30 cents per kwh for residential installations and lower commercial and utility-scale installations with better economies of scale

(IEA, 2006; EIA, 2006a). Solar thermal power is estimated to cost closer to 15 cents per kwh (EIA, 2006a). Both of these estimates are well above most non-renewable power plant costs, even for peak power. However, solar pv costs have consistently declined as cumulative capacity increases. Solar thermal power also has potential for further cost reductions as cumulative capacity increases.

BIOFUEL TECHNOLOGIES

Ethanol

Ethanol is an alcohol fuel produced by fermenting sugar. Ethanol is blended with gasoline for most uses as a motor fuel. Low-level blends, around 10% ethanol, are known as gasohol and common in the United States as the ethanol is added to improve pollution emissions from the automobile. Higher level blends are possible but require modifications to a vehicle to protect the fuel system from ethanol's corrosiveness and adjust the fuel mix in the engine. Cars with these modifications are known as flex-fuel vehicles and can run blends up to 85% ethanol (E85) as well as conventional gasoline.

In the United States, nearly all ethanol is produced from corn. This process has several drawbacks, which are described below, but corn is not the only feedstock used to produce ethanol. Brazil, one of the world's other large producers, makes ethanol using sugar cane. Other potential feedstocks for ethanol include agricultural residues, forestry wastes, and dedicated energy crops such as switchgrass. These alternatives are referred to as cellulosic ethanol as they are produced by converting more energy-dense plant cellulose into sugar.

In 2007, the United States produced about 6.5 billion gallons of ethanol and this value has grown rapidly in the past several years (RFA, 2008). Brazilian ethanol production led the world until 2005 but has lagged U.S. production slightly since then (BP, 2007). The U.S. and Brazil account for over 90% of global ethanol production (BP, 2007). While far behind, ethanol production is also growing quickly in China, Germany, Canada, and Spain (BP, 2007).

Ethanol has several advantages as a fuel. Ethanol production does not require much petroleum and can reduce petroleum consumption when used as a motor fuel. Ethanol can also reduce greenhouse gas emissions; however, the magnitude of the reductions can vary considerably and depends on the feedstock and production process (Farrell et al., 2006). In fact recent research shows that some methods of production for corn-based ethanol may increase greenhouse gases by as much as double (Searchinger et. al., 2008; Fargione et. al., 2008).

Ethanol also reduces emissions of carbon monoxide in automobiles but increases NO_x emissions (GM, 2001). Finally, ethanol production provides a strong stimulus to rural economies, particularly in corn-producing regions.

One of ethanol's main disadvantages is cost. On an energy-equivalent basis (ethanol has less energy per gallon of fuel), corn-based ethanol costs have been greater than conventional gasoline and have been increasing as corn prices rise. Nearly all the ethanol currently produced in the U.S. uses corn as a feedstock. Brazilian ethanol produced from sugar cane uses less energy and is competitive with gasoline at today's oil prices (Budny, 2007). This analysis, however, assumes that imports of Brazilian ethanol remain limited by the current import tariff of \$0.54 per gallon. Cellulosic ethanol is currently not in commercial production and its future costs remain highly uncertain. By using waste products and energy crops that require minimal fertilizer, cellulosic ethanol could have several cost advantages. An important disadvantage is that cellulose is more difficult to convert into sugars and requires a more costly capital investment for the process. Currently, researchers are making considerable efforts to develop new, lower-cost methods to produce cellulosic ethanol.

Even if it was produced at a competitive cost, ethanol has other disadvantages. It has lower energy content and reduces the fuel economy of a car. Ethanol cannot be transported through existing gasoline pipeline infrastructure because it is corrosive and becomes contaminated by water easily. Widespread ethanol use introduces an additional set of environmental concerns over water consumption and pollution.

Biodiesel

Biodiesel is a diesel substitute that is produced from vegetable oils or animal fats. In the U.S., biodiesel is most commonly produced from soybean oil. Producers also make a limited amount of biodiesel with waste grease from restaurants. In Europe, biodiesel is typically made from rapeseed and palm oil. Researchers and several companies are also producing biodiesel from algae but the commercial prospects of this process are highly uncertain at this point.

Biodiesel, like ethanol, is often blended with conventional diesel. Most major diesel engine manufacturers state that biodiesel blends up to 20% are safe and do not void their product warranties (National Biodiesel Board, 2008). Using higher level blends of biodiesel is possible but requires modifications to the fuel system because biodiesel is corrosive to some fuel system components. Furthermore, additional measures are needed when using biodiesel in cold weather.

Biodiesel has both environmental and petroleum reduction benefits. Biodiesel blends can reduce emissions of hydrocarbons, carbon monoxide, and particulate matter. Studies are still inconclusive on biodiesel's impact on nitrogen oxides (NOx). Some studies have shown increases and other have shown decreases in vehicle NOx emissions. Greenhouse gas emissions can decrease with use of biodiesel; however, this result, like the ethanol case, is very sensitive to the feedstock used and the methods of producing the feedstock. Lifecycle analyses on use of soybean oil have shown reductions in greenhouse gases (Hill et al., 2007). Alternatively, a large amount of the biodiesel in Europe comes from palm oil grown by clearing rainforests in Southeast Asia. In these cases, net greenhouse gas emissions can increase as well as other environmental harms (Eickhout et al., 2008). Biodiesel has slightly lower energy content than diesel. The difference is approximately 10% and the fuel economy penalty is not as severe as the difference between ethanol and gasoline. Biodiesel also does not have the same infrastructure compatibility issues of ethanol.

Like ethanol, the main disadvantage of biodiesel is cost. Biodiesel remains more expensive than diesel fuel. It requires a considerable amount of soybean oil to produce one gallon of biodiesel, which limits the total amount of soybean-based biodiesel that can enter the fuel supply. Biodiesel produced from algae does have the potential for widespread use because the algae can be grown in large quantities at power plants and on unused lands. The algae-based production processes still remain at a very pre-commercial state though.

Biomass-to-Liquids

Biomass can also produce diesel- and gasoline-equivalent fuels through a gasification and synthesis process, sometimes referred to as biomass-to-liquids. The initial step of this process involves gasifying biomass using pressure and heat (see biomass electricity section above). This process results in syngas, which is a mixture of hydrogen and carbon monoxide. The gasses are cleaned and then undergo a Fischer-Tropsch (FT) synthesis reaction that produces a diesel-equivalent fuel and naphtha. The naphtha can then be refined into gasoline. An alternative pathway is to convert the syngas into methanol, which can also be converted in gasoline in a process known as methanol-to-gasoline (MTG). The main components of these processes: gasification, FT synthesis, and MTG synthesis are existing technologies in commercial use today. The key difference is that existing plants use coal or natural gas. While biomass-to-liquids plants are not at a commercial state today, the Department of Energy is supporting several pilot plants. In December 2007, the Department of Energy announced \$7.7

million in support for four pilot projects (DOE, 2007a). Several pilot projects are also under development in Canada and Europe.

Biomass-to-liquids has several advantages. The gases are cleaned to remove impurities resulting in clean-burning fuels. The fuels are also close substitutes for gasoline and diesel in both energy content and engine performance. The fuels can also take advantage of existing infrastructure. The net greenhouse gas emissions are significantly lower and can be negative if carbon capture and sequestration are used. A final advantage is that the process uses technologies that are proven and in commercial use today.

The main disadvantage is that biomass feedstocks have not been used on a commercial scale yet in this process and the costs remain uncertain. There are some technical uncertainties to resolve. Gasifying biomass is more difficult because of the higher moisture content and the gas cleaning step involves removing different impurities than coal or natural gas. Similar to biomass electricity, biomass-to-liquids plants face a trade-off between sizing a plant to gain economies of scale and the increase in feedstock costs to supply a higher capacity plant. A higher capacity plant requires producers to transport a feedstock from a greater distance, which can significantly increase feedstock costs.

Other Technologies

The sections above describe the technologies included in this study. Several other renewable technologies exist such as, butanol, tidal and wave power, and municipal solid waste. These technologies were excluded because they were too far from commercial production to be expected to have a major impact by 2025 or their ultimate capacity is limited. They, therefore, are not expected to have a substantial role in meeting a 25% national renewable energy requirement that is implemented immediately. Despite these limits on a national scale, some of these technologies may become important on a regional scale. For instance, experimental wave energy plants are currently permitted off the Oregon coast. In this region, which is relatively remote with low population density, wave energy could contribute to meeting local power demand.

ENERGY EFFICIENCY

Several states allow energy efficient technologies to meet renewable energy requirements under their Renewable Portfolio Standard laws. Generally, these provisions apply to energy-efficient electricity appliances, such as compact fluorescent lightbulbs and highly efficient

refrigerators. This analysis will consider strategies where these technologies qualify towards the renewable electricity requirement and also allow increases in automobile fuel economy to meet requirements on the transportation sector. The policy would include a menu of energy-saving technologies where each has an assumed level of annual energy savings. These technologies could then substitute for renewable electricity or fuels on a per kwh or energy-equivalent gallon basis. Expanding the renewable energy requirement to allow energy efficiency could decrease the cost of the policy while still achieving similar reductions in greenhouse gas emissions and oil consumption. Allowing energy efficiency does involve trade-offs in some of the policy's other objectives. Incorporating energy efficiency into the requirement would reduce investment into renewable energy technologies, decrease the potential learning that occurs, and any resulting reductions in technology costs. In addition, lower investment in renewable energy, especially biomass and biofuels, may reduce the economic boost a renewable energy requirement provides to rural communities. However, the option for energy efficiency would benefit producers of these technologies and potentially benefit consumers if it lowers the cost of the policy requirement.

I have constrained the set of technologies to efficiency-improving technologies that are commercially available today. For electricity, the set of technologies include improvements in technologies used for lighting, electronic equipment, HVAC⁹ equipment, and improvements to building shells. For automobiles, I've considered improvements in the gasoline internal combustion engine, hybrid, and advanced diesel technologies. I also consider improvements to diesel freight trucks. I constrained the analysis to these technologies because they are readily available to consumers today and the cost uncertainties are smaller than non-commercial technologies. Furthermore, several existing studies have analyzed the costs of increasing the use of these technologies, which provide the basis for the cost curves used in the analysis.

This decision to limit the analysis to these technologies excludes several technologies that have promise but still remain in a pre-commercial state. This exclusion leaves out plug-in hybrid vehicles, full battery electric vehicles, and hydrogen-powered fuel cell vehicles. Each of these technologies has potential to improve vehicle efficiency, reduce GHG emissions, and decrease oil consumption; however, the ability for these technologies to reach a commercial state by 2025, their costs, and potential use remain even more deeply uncertain than the technologies considered in this study. For this reason, I've excluded them from the present analysis but they warrant further study.

⁹ HVAC equipment refers to heating, ventilation, and air conditioning equipment.

CURRENT RESEARCH ON RENEWABLE ENERGY REQUIREMENTS

Most current renewable energy requirement proposals focus exclusively on one market and, therefore, most policy analyses of renewable energy requirements have studied either the electricity or fuels markets. This section will summarize the studies on these policies published in the peer-reviewed literature, the EIA, and the US EPA. In general, the studies use different methods, models, and outcome measures. Therefore, they are difficult to compare directly; however, I present some of the main results that are comparable to the analysis in this study as well as discuss the main conclusions.

Renewable Electricity Requirements

As stated earlier, 27 states currently have renewable electricity requirements (33 when including voluntary renewable energy goals) (DSIRE, 2008b). Congress has considered similar legislation numerous times, but has not enacted a national renewable electricity requirement. As a result of these proposals, several studies have assessed the impacts of national renewable electricity requirements at the 10%, 15%, and 20% levels.

EIA (2003, 2007e) analyzed specific legislative proposals for a 10% and 15% renewable portfolio standard using the National Energy Modeling System (NEMS), which is an energy-economic model of U.S. energy markets. EIA published results for the mix of electricity generation under the RPS proposals, fossil fuels displaced, cumulative expenditure change, renewable electricity credit price, average electricity prices, and carbon dioxide emissions. Both of these proposals included a national trading market for renewable electricity credits and a “safety valve” where the government offers an unlimited number of credits for sale when the credit price reaches a threshold. The cap in the 10% proposal was 1.5 cents per kwh and 1.9 cents per kwh in the 15% proposal, which EIA included at the request of the Senators asking for the analysis.

The analyses are not directly comparable because some details of the proposals differed (more than just the RPS percentage shares) and the assumptions EIA uses in NEMS change over time. Despite these differences, some results were consistent across the two analyses. Notably, the amount of renewable generation fell short of the RPS % requirement in both studies. This occurs when the credit price reaches the safety valve and utilities no longer need to develop additional renewable electricity. This result implies the incremental costs of renewable electricity exceeded the safety valve price in both the 10% and 15% cases. A key difference in the two analyses was the mix of electricity projection. In EIA’s 2003 analysis of a 10% RPS, they

projected that wind power would produce 93% of the incremental renewable electricity to meet the RPS, and the remaining renewable electricity would come from biomass cofiring. Dedicated biomass power provided no additional power to meet the requirement. In the 2007 study of a 15% requirement, EIA projected that dedicated biomass plants would produce almost 80% of the incremental renewable electricity, and wind comprised nearly all the remaining power. Between the two analyses, EIA revised their assumptions about dedicated biomass power plants to assume that biomass plants will use IGCC technology. These plants have significant increases in efficiency over plants using direct combustion of biomass. The biomass-fueled IGCC plants can also gain from improvements in this technology by learning in coal-fueled IGCC plants. EIA projected a considerable increase in the amount of coal-fired IGCC plants and the resulting cost reductions also benefit biomass-fueled IGCC plants. The drastic change in results shows the projections are very sensitive to technology cost assumptions.

Kydes (2007) also used the NEMS to analyze a national 20% RPS. His analysis of the policy included a renewable credit trading market but did not include a safety valve. In this study, the largest increase in renewables occurred for dedicated biomass and biomass cofiring plants. There was also a substantial increase in wind power. The credit price rose to near 6 cents per kwh and then leveled off near 4 cents per kwh, presumably due to learning effects decreasing the cost of renewables. His analysis also included the resource cost of the policy. This is the incremental capital and fuel costs of substituting renewables for fossil fuels over the analysis period, including any decreases in the prices of natural gas and coal. Using different assumptions about the discount rate, he found the net present value (NPV) of the resource cost varied from \$35 to \$60 billion (2000 US\$).

Fischer and Newell (2008) did not analyze a specific legislative proposal but they compared several policy instruments in achieving a set level of greenhouse gas emissions reduction. The policies included an emissions tax, tradable emissions performance standard, tax on electricity produced from fossil fuels, renewable portfolio standard, renewables production subsidy, and renewable research subsidy. They developed a model with an emitting and non-emitting electricity sector that maximizes the NPV of profits. Their model also allowed R&D and learning to lower the future costs of renewable energy and it could therefore analyze how the different policies addressed the market failures due to GHG emissions and spillovers from learning. They estimated the model based on EIA projections from the NEMS and calculated the change in total surplus with each policy. They found that the following rank order of the policies based on the lowest change in surplus: emissions tax, tradable emissions

standard, fossil fuel output tax, RPS, renewable production subsidy, and renewables research subsidy. The surplus decrease with the RPS was about two times larger than the emissions tax. They also considered combinations of policies and found the combination of the emissions tax, R&D subsidy, and production subsidy resulted in a slight increase in surplus. This combination of policies was the most efficient because it used price instruments directly targeting the three market failures: GHG emissions, technology innovation, and spillovers from learning.

Renewable Fuels Requirements

The literature on renewable fuels requirements is more limited. EIA (2005b) conducted analysis on several competing legislative proposals that Congress considered at that point. They required increases in renewable fuels between 5-8 billion gallons by 2012. In nearly all the proposals, EIA projected that corn-based ethanol would meet most of the requirement, but some cellulosic ethanol production would occur by 2025. The report has only limited detail on the economic impacts. It estimated gasoline prices would rise less than 1 cent per gallon, assuming the 51 cent per gallon tax credit for blenders remained in place through the period. Expenditures for gasoline increased between \$0.3 - \$1.7 billion in 2012 and \$0.5-\$2.4 billion by 2025 (2003\$). The increase in cumulative tax expenditures for the ethanol subsidy varied from \$3.5 - \$10.6 billion (2003 \$).

Gallagher et al. (2003) used a simulation model to estimate the impacts of two policies: a MTBE ban and renewable fuels standard requiring 5 billion gallons of ethanol supply by 2015. In their 2015 baseline, they assumed ethanol production of 4.4 billion gallons. The MTBE ban increased ethanol production 4.5 billion gallons and a renewable fuels standard expanded ethanol production to 5 billion gallons. Their model estimated the welfare effects of these policies. They found 2015 welfare decreased by \$18 billion with the renewable fuels standard (loss was \$19 billion with the MTBE ban), which translated into the losses of \$60 per person annually. A key caveat to this analysis is that Gallagher et al. calibrate their model to the EIA AEO 2002. The AEO 2002 reference case projection for crude oil prices in 2015 was \$24 per barrel (2000 \$) (EIA, 2002), which is obviously far below today's oil prices and the EIA's current projections for this time period. In the AEO 2008, the EIA projects 2015 crude oil prices at \$52 per barrel (2006\$).

EPA (2007) conducted a detailed study of the renewable fuels market in the Regulatory Impact Analysis (RIA) on the RFS program. In this report, EPA estimated the incremental costs of renewable fuels for the RFS of 7.5 billion gallons of renewable fuels by 2012. They used a

linear programming model of the nation's system of refineries to estimate the savings from lower gasoline production versus the costs of higher ethanol production. The EPA assumed corn-based ethanol costs would vary from \$1.38 per gallon to \$1.53 per gallon (2004\$) in different regions of the country (lower costs in the Midwest and the highest costs in California). On a per-gallon basis, the EPA found that the incremental cost were \$0.50 per gallon (2004\$, excluding ethanol subsidies). EPA performed sensitivity analysis using a range of ethanol costs from \$0.86 - \$2.04 per gallon (2004\$) and found the incremental costs varied from -\$0.16 to \$1.79 per gallon (2004\$, excluding ethanol subsidies).

25 x 25 Electricity and Fuels Requirement

To date, three studies have assessed the 25 x 25 policy proposal. In December 2006, researchers from the University of Tennessee released an analysis of a 25 x 25 policy that focused on the policy's effects on the agricultural sector (English et al., 2006). In September 2007, the EIA published a report using the NEMS to analyze the policy (EIA, 2007c). Finally, a 2008 RAND report analyzed the impacts of a 25 x 25 policy on U.S. energy expenditures and GHG emissions, and was completed at the request of the Energy Future Coalition (EFC) (Toman et al., 2008). Each of these reports varies in their assumptions, analytical methods, and measures.

English et al. (2006) found that the policy requirement significantly boosted agricultural land values, reduced government spending on farm subsidies, and increased farm commodity prices. They confined their analysis to only the agricultural sector and did not assess how higher land and commodity prices affected consumers. The EIA estimated 2025 energy expenditures increase \$9 billion in the electricity market and \$68 billion for transportation fuels. By 2030, the policy raised electricity expenditures by \$16 billion and \$50 billion for transportation fuels. EIA also projected that prices rise by 4% for electricity, 13% for gasoline, and 20% for diesel. The EIA report explored the possible risks in the policy requirement more explicitly and in greater detail than English et al. (2006).

Similar to the EIA (2007e) study on a 15% RPS, EIA's 25 x 25 analysis found that dedicated biomass power provides a significant portion of the incremental renewable electricity. Electricity generation from dedicated biomass plants increased by 10 times and comprised approximately 50% of the new renewable electricity produced to meet the requirement. The increase in renewable electricity to 25% added 374 billion kwh of new wind power. In another change from earlier analyses, the EIA relaxed a constraint on corn-based ethanol production.

The projections found that total corn-based ethanol production rose to over 25 billion gallons in 2030, which would consume 60% of domestic corn production. The remainder of the requirement is fulfilled by cellulosic ethanol and ethanol imports. Their analysis also projected that this level of biomass-based energy for electricity and cellulosic ethanol consumed 579 million tons of biomass, excluding wood and forestry waste used for electricity which was not quantified. The market clearing price for biomass was approximately \$75 per ton. As will become apparent in the following chapters, the competition of the electricity and motor fuels sectors over a common biomass supply, and the available supply of biomass and delivered costs are some of the largest uncertainties in this analysis.

Toman et al. (2008) used methods of exploratory analysis to examine the effects of a 25 x 25 policy on U.S. energy expenditures and greenhouse gas emissions. This study analyzed the policy requirement across a wide array of future uncertainties in energy markets and included several different mechanisms to implement the policy requirement. Prior studies only considered one policy design to implement a 25 x 25 requirement. This dissertation builds on the models and methods used in Toman et al. (2008) by extending the models to perform social welfare calculations, expanding the set of resources in the model to include additional corn ethanol supply and energy efficiency, and analyzing multiple strategies to implement the policy requirement to find one (or more) that performs reasonably well across the range of uncertainties in future energy markets.

Table 2 summarizes some of the key results from the studies described in this section. As stated earlier, the results are not all directly comparable because of the differences in policies, models, and baseline assumptions. The table also shows the year used for the comparisons in outcomes and the year dollars used in the study.

Table 2: Summary of Renewable Energy Requirement Studies

Study	Market	Requirement Level	Time Horizon	Year Dollars	Price Change (cents per kwh or cents per gallon)	Incremental Cost (cents per kwh or \$/gall)
EIA (2003)	Elec	10%	2025	2001	0.1 (1.5%)	0.83
EIA (2007g)	Elec	15%	2030	2005	0.16 (2.0%)	1.84
Kydes (2007)	Elec	20%	2020	2000	-	4.0 - 5.5
Fischer and Newell (2008)	Elec	9.6%	-	2004	-0.065 (-0.9%)	1.2
EIA (2005)	MF	5 bill galls	2025	2003	0.5 - 0.9	-
Gallagher et al. (2003)	MF	5 bill galls	2015	2000	-	-
EPA (2007)	MF	7.5 bill galls	2012	2004	-	0.50 (-0.16 - 1.79)
English et al. (2006)	Elec	25%	2025	Unc	-	-
English et al. (2006)	MF	25%	2025	Unc	-	-0.08 - 0.07 (-5%-5%)
EIA (2007c)	Elec	25%	2030	2005	0.5 (6.3%)	4.5
EIA (2007c)	MF	25%	2030	2005	24 (11%)-gas 39 (17%)-diesel	2.02
Toman et al. (2008)	Elec	25%	2025	2004	0.5-3.0 (3%-42%)	-
Toman et al. (2008)	MF	25%	2025	2004	-18 - 426 (-9%-200%)	-

Elec = electricity, MF = motor fuels, Unc = uncertain

Study	Resource Cost (billion \$)	Welfare Change (billion \$)	Expenditure change (billion \$)	Greenhouse Gas Emissions Change (million metric ton CO2 eq)	Petroleum Consumption Change (million barrels per day)
EIA (2003)	-	-	-	20 (2.3%)	-
EIA (2007g)	-	-	-	222 (6.7%)	-
Kydes (2007)	35 - 60*	-	-	130 (6.2%)	-
Fischer and Newell (2008)	-	-0.48	-	129 (5.3%)	-
EIA (2005)	-	-	0.5 - 2.4	-	0.02 - 0.03
Gallagher et al. (2003)	-	-17.6	-	-	0.49
EPA (2007)	0.823**	-	-	11	0.13
English et al. (2006)	-	-	-	-	-
English et al. (2006)	-	-	-	-	3.9
EIA (2007c)	-	-	16 (3.9%)	768 (15%)	-
EIA (2007c)	-	-	50 (7.7%)	370 (14%)	3.54
Toman et al. (2008)	-	-	-0.1-62 (0% - 17%)	448-940	-
Toman et al. (2008)	-	-	-150 - 214 (-30% - 43%)	453-1478	-

* = cumulative resource costs, ** = annual resource costs at end of time horizon

The table reports the outcome metrics used in each of the studies (blanks occur because studies used different metrics). The price change refers to projected changes in retail electricity or gasoline prices. Incremental costs are the additional costs of renewable energy over fossil fuels at the margin (because of the policy). Resource costs are the total incremental capital and variable costs incurred in implementing the policy. Welfare change is the change in consumer and producer surplus. Expenditure change is the change in consumer expenditures on electricity or motor fuels. The final two columns show the estimated changes in greenhouse gases and petroleum consumption.

A few patterns are evident from the table. Costs generally increase for higher requirement levels in both markets. The total benefits of reducing GHGs and petroleum use also rise at higher levels of the requirement. Another pattern is that the costs in the fuels market generally exceed the electricity market. A challenge in comparing results across markets is that most of the studies use different models, and even the studies using the same models, such as EIA's analyses, change their assumptions over time. EIA's 25 x 25 study avoids these potential confounding factors because the requirement level and many of the macroeconomic assumptions are consistent across markets. Comparing the incremental costs of the policy across the two markets with this study, and adjusting the figures on an energy-equivalent basis, shows that in 2030 the incremental costs are \$23.9 per million BTU for the motor vehicle fuels and \$13.2 per million BTU for electricity. The incremental costs to reach the 25% requirement for motor vehicle transportation fuels are almost double those to reach the electricity requirement.

Toman et al. (2008) has a much broader range of results because of the underlying wide range of assumptions. Of particular note, the range of expenditure changes in the motor fuels market spans all three pricing mechanism used to implement the policy (from full subsidization of renewables to a fossil fuel tax), and because these assumptions vary considerably from other studies comparing the full range of results on this metric in particular is difficult. The large negative expenditure changes occur when fossil fuel tax revenues collected from consumers exceed higher spending on renewable energy. Readers should not interpret the result as a large reduction in spending on energy consumption.

This chapter summarized the key background information on renewable energy requirements, current renewable energy use in the U.S., debates in the literature on the main justifications for a 25 x 25 policy, descriptions of the renewable energy technologies included in this analysis, and prior policy research on renewable energy requirements. The discussion

showed several strong justifications for increasing renewable energy use. These include market failures due to the external costs of greenhouse gas emissions and high oil dependence that firms and consumers do not account for in their economic decision-making. In addition, the literature showed that firms may not realize all of the benefits of innovation in and diffusion of renewable energy technologies resulting in suboptimal investment in these technologies. The literature on the foreign policy implications of high oil dependence showed that U.S. oil consumption transfers significant wealth from U.S. consumers to oil-producing nations, which harms U.S. interests with several nations but also benefits several allies. The dependence of other oil-consuming nations on energy producers may also harm U.S. foreign policy efforts.

In discussing the arguments of proponents and critics of renewable energy requirements, I've noted that both sides primarily focus on the distributional effects of the policy requirement, which are significant. The requirement will considerably increase U.S. investment in renewable energy sources and expand employment in renewable energy-related industries. Fossil fuel producers will lose a portion of their market share and employment in these industries will decline relative to a "no policy" baseline. Traditional economic analysis focuses on the costs of the policy to economic efficiency, which are the changes in consumer and producer surplus. The next chapter will discuss the analytical models used to estimate the effects of the policy and the methods used to analyze the uncertainties in future energy markets. As noted in the sections on current renewable energy use and technologies, a 25 x 25 policy requirement will expand capacity of these existing technologies far beyond current use and require commercialization of several technologies that are currently in a pre-commercial state. Chapters 3 and 4 will show that the outcomes depend on how these technologies progress and their costs at this level of utilization. In the next chapter, I first discuss the methods employed to analyze deep uncertainties in future energy markets and then describe the numerical models developed to assess this policy.

CHAPTER 2: RESEARCH APPROACH

In this chapter, I provide an overview of the analytical methods I use to assess the 25 x 25 renewable energy requirement, describe the simulation models developed for this project, explain the outcome measures used in the analysis, and finish with the discrete steps used in applying the analytical methods. I begin by describing decision problems with deep uncertainty and the analytical methods I've used in this analysis.

DEEP UNCERTAINTY AND ROBUST DECISION MAKING

Future energy markets are subject to many deeply uncertain factors, such as changes in technology costs, primary energy prices, introductions of disruptive technologies, and government policy. Analysts differ widely on the future trends in these variables, decision makers face the problem of choosing among different actions (policies) with uncertain future outcomes. A considerable body of research has developed since World War II to help analyze these decisions under uncertainty. Most of these methods of decision making under uncertainty frame the decision maker's choice as a utility maximization problem where the decision maker chooses the action (policy) that maximizes their expected utility.

This model of decision making requires the decision maker to know the exhaustive set of actions available, all of the possible states of the world, define probabilities over the states of the world, know the function mapping actions and states of the world to outcomes, and have well defined preferences over the outcomes. These requirements can work well for many decision problems; however, with some problems decision makers and stake holders may poorly understand or vigorously debate many of the key elements of the decision problem. In some cases, many of the elements may be completely unknown. Lempert, Popper, and Bankes (2003) refer to problems characterized by these conditions as deeply uncertain and in problems with deep uncertainty the traditional models of decision making under uncertainty may perform poorly.

Lempert, Popper, and Bankes (2003) and Lempert et al. (2006) suggest robust decision-making (RDM) as an alternative for decisions characterized by deep uncertainty. Lempert et al. (2006) define a robust decision as one that performs reasonably well—compared to other possible decisions—across a broad range of plausible futures and contrast this criterion with optimality, which is the basis of decision analysis using traditional methods outlined above.

They argue that in problems characterized by deep uncertainty the optimal decision may be highly sensitive to the assumptions made in the decision problem and multiple optimal choices may emerge when varying the parameters in the problem. They also offer an analytic method for generating robust strategies using the following steps:

1. Identify initial candidate strategy – The analyst and/or decision maker(s) start with an initial strategy, which is evaluated across the range of possible futures.
2. Identify vulnerabilities – The analyst assesses the candidate strategy on a range of metrics and identifies the scenarios where the strategy performs poorly.
3. Suggest hedges against vulnerabilities – Using the information from the previous step, the analyst devises new strategies to mitigate the vulnerabilities identified in initial strategy.
4. Characterize deep uncertainties and trade-offs among strategies – The analysis in steps 1-3 generally allows the analyst to reduce the problem to a limited number of dimensions or situations. The analyst also identifies trade-offs in performance between outcomes for each strategy.
5. Consider improved hedging options and surprises – The analyst again considers new strategies and additional uncertainties to include in the analysis. This can be an interactive process with decision makers and stakeholders. The RDM process then iterates through the five steps presented here.

A central feature in this type of analysis is a computer model of the system. The model is typically a low-resolution simplification of the system that the analyst can evaluate over a large number of scenarios. The analyst develops an ensemble of future scenarios based on a sample of the future states of the world. The analyst then uses the model to evaluate each strategy across the range of scenarios and determines the set of conditions where a strategy or action performs well or poorly. After analyzing the initial set of strategies, the analyst revises strategies to hedge against the conditions where they perform poorly. After several iterations, the analyst judges the robust strategies, which are strategies that perform reasonably well relative to other strategies across the broad range of uncertainties.

In this study, I've selected this method of uncertainty analysis because future energy markets are deeply uncertain. For this particular problem, assigning probabilities to future renewable energy technology costs at the capacities used at the 25% level is extremely difficult.

Existing technologies, such as wind and biomass power, will need to scale up far beyond current levels. In addition, several technologies that are currently in a pre-commercial state, such as cellulosic ethanol and biomass-to-liquids, will need to reach a commercial state and increase production to meet the 25% requirement. Defining probabilities over these uncertain variables is difficult because the potential for surprises that could either raise or lower costs is very high. In the final section of this chapter, I describe the discrete steps in the uncertainty analysis in greater detail. Before that, I describe how I implement the 25 x 25 policy, the simulation models used in the analysis, and outcome measures.

25 X 25 POLICY REQUIREMENT AND SIMULATION MODELS

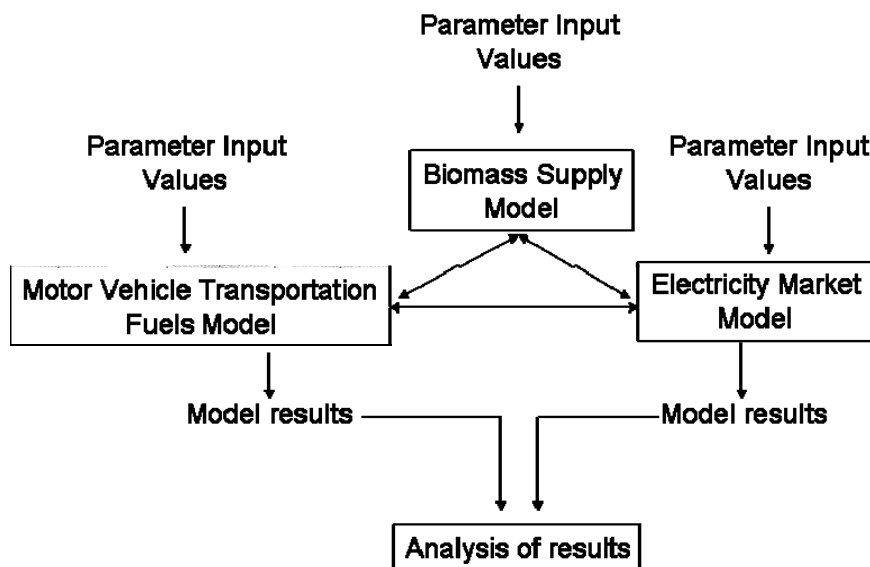
I implement the 25 x 25 policy requirement in the electricity and motor vehicle transportation fuels sectors. I calculate the required amount of renewable energy using demand equations parameterized with the EIA's AEO 2006 projected 2025 demand for delivered energy from electric utilities and combined demand for gasoline and diesel fuels by light-duty vehicles, commercial trucks, and freight trucks. Of note, this choice in the transportation sector excludes energy demand from air, rail, and marine transportation. This closely follows EIA's implementation of this requirement in their 25 x 25 analysis, but differs from the analysis on a 25 x 25 policy by English et al. (2006). English et al. (2006) calculated required renewable energy using total demand for primary energy, which is a larger initial energy demand because the electricity and transportation sectors account for approximately two-thirds of total energy consumption. Total primary energy also includes energy losses, which are considerable in the electricity sector.

I confined the analysis to these sectors because existing renewable energy requirements target these sectors. Therefore, a national level policy can build on existing policy. Furthermore, existing renewable energy technologies are most substitutable for electricity and liquid fuels used in the transportation sectors included in the analysis. For instance, current biofuels are not a readily available substitute for jet fuel. Finally, in most of the results I show in Chapters 3 and 4, I implement the 25 x 25 policy in the motor vehicle fuels market using pricing policy that combines a tax on fossil fuels and with a subsidy for renewable fuels. I also present results for an option that only taxes fossil fuels and raises their prices enough to induce 25% of the fuel supply from renewable fuels. Alternatively, I use average cost pricing in the electricity market because of limitations in the models. These are not the only measures policy makers

could use to implement the requirement. The government could also subsidize renewable fuels to induce 25% of the fuel supply from renewable fuels. The government could also choose to subsidize research and development of renewable energy. I list these policy options because the discussion later in this chapter will show that the choice of policy instruments to implement the policy has important effects on the social welfare costs.

The quantitative analysis uses a set of simulation models that represent energy supply and demand in the electricity and motor vehicle transportation fuels markets. The models were developed at RAND for a report on the impacts of a 25 x 25 policy requirement on U.S. energy expenditures and greenhouse gas emissions. The models received considerable internal and external peer review during this process (Toman et al., 2008). Figure 6 shows a conceptual diagram of the models:

Figure 6: Flow Diagram of Simulation Models



The diagram shows that the analysis begins with a set of parameter inputs. These inputs reflect different assumptions about key factors such as energy technology costs, available renewable energy capacity, and elasticities of demand and supply. Separate simulation models representing market supply and demand for electricity and motor vehicle transportation fuels substitute renewable energy for fossil fuels and calculate the resulting changes in costs, greenhouse gas emissions, and energy demand. Within each of these models, another set of

supply and demand models estimate how increasing renewable energy and decreasing demand for fossil fuels affects the price of these commodities. A module for biomass feedstock supply interacts with both models to calculate demand for biomass and a market price. After calculating the model results, I use an additional set of analyses on the results to identify the set of key factors leading to high-cost and low-cost outcomes. This analysis identifies the weaknesses of a strategy to implement the renewable energy requirement and is used to develop new strategies that hedge against the weaknesses.

Each of the model components described above utilizes the same five steps to estimate energy demand and prices, which are then used to determine a market equilibrium:

- Construct a set of cost curves for renewable energy technologies based on assumptions about technology costs and capacity;
- Estimate additional supply costs for meeting renewable energy requirement;
- Determine substitution effects of renewable energy use on fossil fuel markets;
- Calculate new market prices for energy consumers; and
- Estimate new energy demand based on new prices.

The two models iterate through this sequence until the deviation in demand between model runs is less than one percent. Furthermore, the two models are integrated at several steps to reflect competition over biomass supply. The discussion will now focus on the basic concepts in each of these steps and then how they are applied to each of the energy markets.

Step 1: Construct Cost Curves for Renewable Energy Technologies

Each model uses a set of cost curves that relate how the marginal costs¹⁰ of a renewable energy source increase as the amount of capacity added to the system increases. For most renewable energy sources, the marginal costs of supply increase at higher levels of capacity, because the most accessible, least-cost resources are developed first, followed by more expensive resources. As the amount of new electricity capacity built increases, for example, the marginal costs for successive power plants increase until they reach an asymptote that represents the limit to power available from a particular source.

¹⁰Marginal costs are the costs of producing the next unit of a good.

The range of technology cost estimates come from various existing technical reports on each renewable energy technology. For most renewable technologies, the amount of existing capacity is small and estimates of today's technology costs can be used to estimate the initial portions of the supply curve. Beyond the initial portions of the curves, limited information exists on how costs escalate as new capacity increases, and the shape of these curves is one of the significant uncertainties in this study.

Because of the significant uncertainties on the shape of these curves, I treat them as parameters to vary in the uncertainty analysis. Each set of assumptions yields a set of cost curves for individual technologies. In the next step, the model builds an aggregate curve from the individual technologies, which is used to estimate the costs of a requirement.

Step 2: Estimate Costs of Meeting Requirement

In this step, an aggregate curve is built based on the individual curves for each technology. The model creates an aggregate curve by combining cost curves from each technology and plotting constituent components of the curves from least cost to most expensive. Once the curve is built, the model determines the costs of providing renewable energy to meet a set requirement.

The following example shows how this step works. The AEO 2006 estimates the demand for motor vehicle transportation fuels in 2025 at 13.5 million barrels per day motor fuel in gasoline-equivalent units (206.4 billion gallons), and the resulting renewable energy requirement is 3.4 million barrels per day (51.6 billion gallons) of renewable fuels in gasoline-equivalent units. By intersecting this level of demand with the aggregate cost curve, the corresponding level on the vertical axis is the marginal cost of producing the required level of renewable fuels.

Step 3: Substitute Renewable Fuels for Fossil Fuel

With the information from the prior step on the amount of renewable energy produced, the model calculates the amount of fossil fuels displaced by renewable energy. The substitution of biofuels for gasoline and diesel fuels lowers U.S. demand for crude oil. The model uses basic representations of supply and demand to determine how much demand for oil drops and how

the market price changes in response. For the electricity sector, the model does equivalent calculations for coal and natural gas demand and prices.

Step 4: Calculate New Market Prices for Energy Consumers

In Step 2, the model determines the cost of producing the required level of renewable energy. In this step, this information is then combined with information on the cost of producing energy from fossil fuels into a single market price. How these costs are combined depend on assumptions about the policies used to meet a renewable energy requirement. For instance, renewable energy could be subsidized by a sufficient amount to generate the level of production needed to meet the set requirement. Alternatively, fossil fuels could be taxed to equalize the prices. Finally, a policy could be put in place that combines taxes and subsidies to meet the renewable energy requirement. In the end, consumers see one price for fuel at the pump or on their electricity bills. The model can accommodate a range of policy assumptions that combine the costs of renewable energy and fossil fuels to yield a single market price for consumers.

Step 5: Estimate Energy Demand Based on New Prices

Step 5 uses the price information determined in the previous step to estimate new demand for motor fuels and electricity. The models use basic demand equations in both the electricity and motor fuels markets that are calibrated to EIA's energy projections. The new market price from the previous step is plugged into the demand equation to estimate a new demand. If there is a large difference between the demand calculated at this stage and the demand used at Step 2, then the model iterates again. In the next iteration, the demand estimated in this stage becomes the initial value used in Step 2.

This discussion broadly describes the steps involved in each component of the model. The next two sections describe how they apply to the individual markets. There are important differences in the electricity and motor fuels markets that I adjust for in each component of the model. Those components are now described in more detail.

MOTOR VEHICLE TRANSPORTATION FUELS MODEL

Most current discussion in the United States on renewable fuels focuses on using ethanol to substitute for gasoline. Nearly all ethanol currently produced in the US is derived from corn and as discussed earlier is a process that has problems when used on a large scale. Corn-based ethanol is expensive when accounting for the direct costs of producing ethanol but even more so after accounting for the opportunity costs of using food as a fuel source. Corn-based ethanol also has limited greenhouse gas benefits and may exacerbate the problem in some situations.

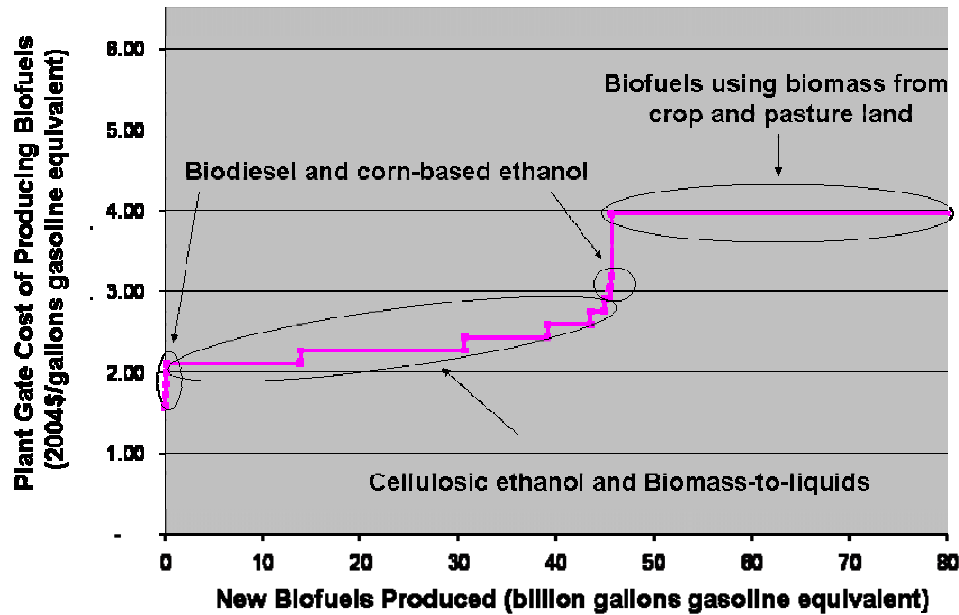
With these limitations on corn-based ethanol, significantly expanding renewable fuels will require vastly increasing production of alternatives to corn-based ethanol. This analysis focuses on three alternatives: cellulosic ethanol, biomass-to-liquids, and biodiesel. Cellulosic ethanol and biomass-to-liquids production are not currently in a commercial state; however, considerable research and investment is going into these technologies today. Biodiesel is currently produced and available to consumers, but on a limited basis. None of these technologies is near the level of capacity that would be necessary under a 25% requirement in the fuels sector and the range of future costs of these technologies is highly uncertain.

For these reasons, developing a set of cost curves for biofuels technologies was exceptionally difficult. Instead of trying to make a most likely estimate, the analysis uses a broad range of possible costs and potential capacities. The model characterizes each technology with two parameters: a conversion cost and conversion yield. The conversion costs represent the capital and operating costs for converting biomass feedstock into biofuels. The conversion yields represent the amount of biofuels produced per unit of biomass input.

Following the general steps outlined in the opening subsection, the model integrates the cost curves for individual biofuels technologies into an aggregate curve and then intersects the demand for biofuels with the aggregate curve. This provides an estimate of the marginal cost of producing biofuels. A markup to marginal costs is then added to reflect the costs of distribution, retail marketing, and taxes, which are based on projections from the Department of Energy. In the end, the model estimates the retail cost of producing biofuels.

Figure 7 shows an example of a biofuels supply curve under one set of assumptions in the middle of the assumed range.

Figure 7: Example Biofuels Supply Curve and Biofuels Demand Under One Set of Parameter Assumptions



The graph shows the amount of biofuels available at successively increasing marginal costs of supply. Under these assumptions, a limited amount of biodiesel produced from “yellow grease” or waste oil from restaurant grease traps provides the low-cost supply, followed by cellulosic ethanol and biomass-to-liquids. I assume a portion of the biomass for these fuels comes from low-cost supplies that are waste residues or grown on marginal lands. Higher-cost biodiesel from soybean oil and corn-based ethanol comprise the upper portion of the supply curve. Under different assumptions, the curve changes shape and technologies can occupy different relative positions. Finally, on the upper portion of the supply curve, biofuels are produced with biomass grown on land converted from growing crops or grazing livestock. An important note is that this analysis initially follows assumptions in the AEO 2006 limiting the amount of corn ethanol produced to 12 billion gallons per year. I have developed a separate supply curve for corn ethanol and analyze strategies where the amount of corn ethanol used to meet the requirement is unconstrained.

After creating the aggregate supply curve, the model estimates the marginal cost of renewable energy by finding the point where biofuels demand intersects the curve. Biofuels

demand is the total demand for motor vehicle transportation fuels multiplied by the renewable energy requirement level. The marginal cost of meeting the requirement is the point where biofuels demand intersects the supply curve. This intersection point also determines the relative mix of biofuels produced.

After calculating the amount of each biofuel produced, the model calculates the amount of oil displaced by biofuel production and the impact of this decrease in demand on the world price of oil. This change in the price of oil also results in a change in the price of gasoline and diesel fuel for consumers. The model uses a basic model of oil demand and supply that is benchmarked to data from the Department of Energy.

In the fourth step, the model calculates the retail prices of biofuels and fossil fuels. The model allows for several potential mechanisms that affect the market prices that consumers see at the pump. One mechanism is government subsidies to equalize the cost of biofuels with gasoline and diesel. A second is a revenue-neutral tax-and-subsidy policy where fossil fuel taxes generate the needed revenue to subsidize the amount of biofuels to meet the policy requirement. A third is a tax on fossil fuels that equalizes the price of fossil fuels and biofuels.

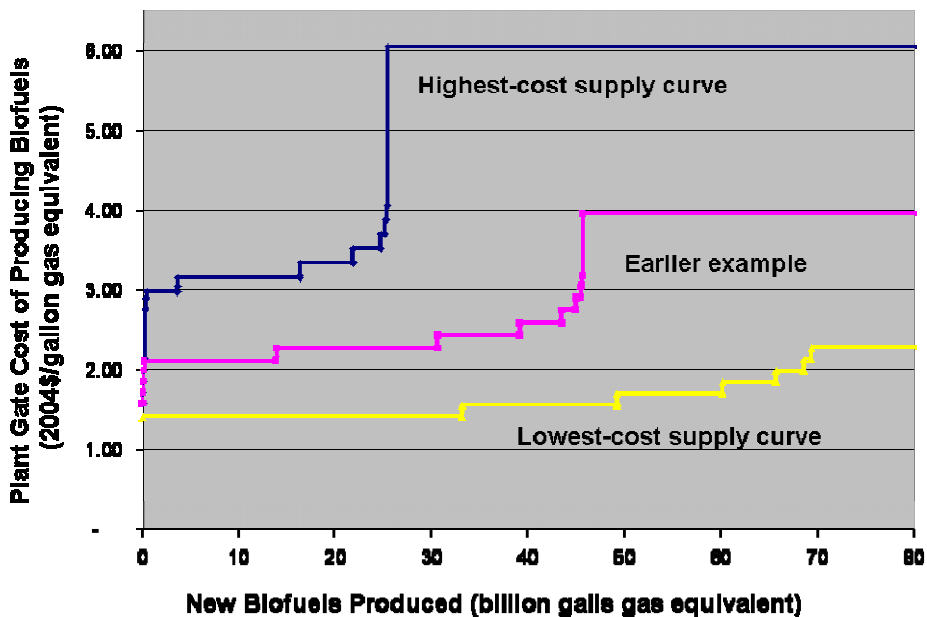
A simple example will help demonstrate how these pricing mechanisms work. Suppose the fossil fuel (gasoline or diesel) costs \$1 per gallon and the biofuel alternative costs \$2 per gallon in energy-equivalent terms. Under the subsidy program, the government would pay biofuel producers \$1 for each gallon produced, and, thus, the market price of fuels would be \$1 per gallon. Total expenditure equals the sum of consumer and government outlays. With the fossil fuel tax, the government would assess a \$1 tax on each gallon of fossil fuel sold, and, thus, the market price of fuels would be \$2 per gallon. Impacts on consumer outlays would reflect the tax and the government would accrue revenue. In the revenue-neutral tax and subsidy system, each fossil fuel producer is taxed \$0.25 per gallon because for every three gallons of fossil fuels sold one gallon of biofuels is required. Biofuels producers receive a \$0.75 subsidy per gallon, and the market price of fuels would be \$1.25 per gallon. The example shows that the pricing mechanisms significantly affect the prices consumers see at the pump for the same underlying set of cost factors, and as the results displayed shortly show, have important implications for consumer behavior and policy costs.

In the final step, the model uses a basic representation of motor fuels demand to estimate the change in demand as prices change. The analysis considers fuels demand from a subset of the transportation sector. It includes petroleum fuel demand by light-duty vehicles, commercial trucks, and freight transport. This represents the vast majority of gasoline and

diesel demand in the transport sector. The analysis focuses on these markets because they already have some use of biofuels and assumes that biofuels will expand in markets where production already occurs.

The description above provides an overview of the biofuels market in the model. Figure 8 illustrates the range of biofuels supply curves used in the analysis.

Figure 8: Range of Biofuels Supply Curves Used in Analysis



Each curve shows the marginal cost of producing a particular level of biofuels. (All figures represent plant gate costs; costs of distribution, marketing, and taxes are added subsequently.) For reference, the supply curve in the middle represents the earlier example curve shown in Figure 7. The higher-cost supply curve uses the most costly assumptions in the range assumed for the analysis, while the lower-cost supply curve uses the least-cost assumptions. As a reference, the AEO 2006 projects the wholesale price of gasoline in 2025 at \$1.53 per gallon. The key parameters that affect the biofuels supply curves are the supply of low-cost biomass feedstock, yield of biofuels per unit of biomass, conversion costs of producing biofuels, and feedstock price for biomass from land conversion.

Each scenario run in the model uses a particular combination of input parameters that constructs a supply curve within the range shown in this graph. Therefore, the model can be

used to explore the implications of uncertainty about the future values of these parameters on the cost of meeting a 25 percent renewable energy requirement.

Note also that in Figure 8, each of the biofuels supply curves reaches a backstop after exhausting the low-cost supply of biomass. The backstop supplies are produced by converting existing agricultural or pasture land into energy crops. The model calculates the amount of land use conversion when biomass comes from these sources.

ELECTRICITY MARKET MODEL

The electricity market component follows the same basic steps as described above. However, the model includes some unique characteristics to account for differences in electricity demand and supply and for limitations in the data for the analysis. Electricity requires different treatment because of the technical characteristics of the technologies. Some renewable sources, such as a dedicated biomass power plant, provide firm power that a system operator can control. Other technologies, such as wind, are intermittent and only produce electricity when the resource is available.

The model calculates the policy's effects by determining the incremental costs of substituting renewable energy for nonrenewable sources in the system. This substitution reflects both the use of new renewable capacity in lieu of nonrenewable capacity and fuel substitution. With respect to the former, the Department of Energy projects that about 160 GW of new electricity capacity, of which renewables comprise about 6 percent, will come online between 2010 and 2025 to replace aging plants and meet growth in electricity demand. This analysis looks at the cost of using renewable electricity instead of nonrenewable sources in these new plants.

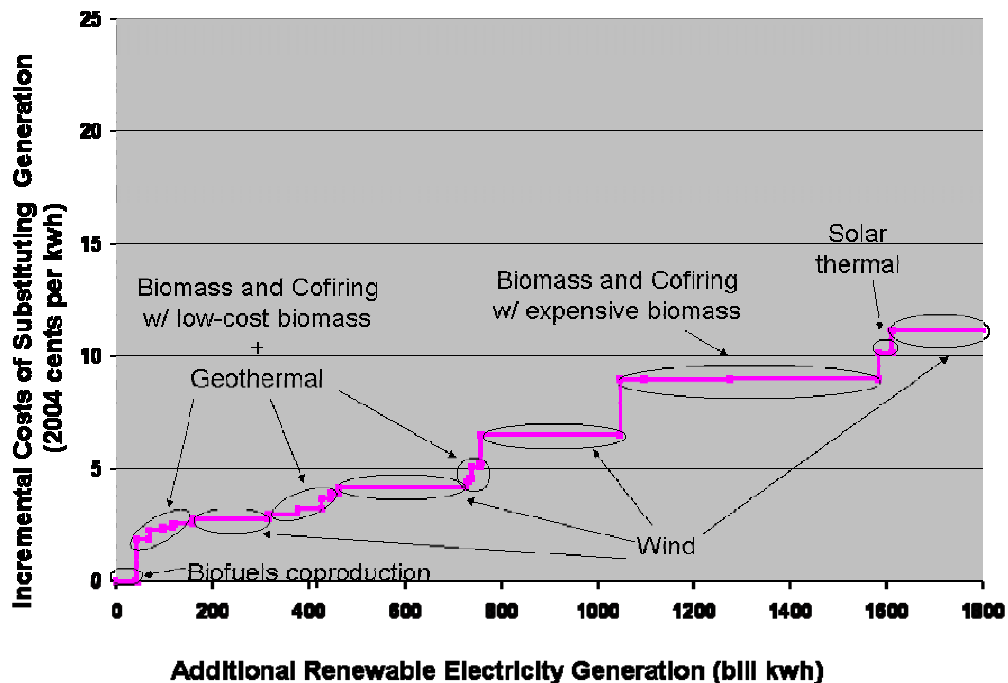
In the analysis, the supply curve includes electricity produced by onshore wind turbines, geothermal, dedicated biomass plants, coal plants cofired with biomass, and solar thermal power plants. As a baseline, the analysis uses the AEO 2006 assumptions about 2020 technology costs, 2025 electricity generation and prices, and addition of new capacity from 2010-2025. In the first step of the analysis, the model estimates the incremental substitution costs of bringing more renewable energy into the electric system to satisfy the 25 percent requirement.

For each technology, the model calculates the difference in the levelized costs of electricity (LCOE) between the renewable technology and the nonrenewable alternative(s) and

the available capacity. This calculation takes a different form depending on whether the renewable electricity source is firm capacity (such as dedicated biomass), a fuel switching technology (such as cofiring), or an intermittent source (such as wind). Each of these technology types has a differing ability to offset nonrenewable capacity, and the methods for calculating their incremental substitution costs vary. For firm power sources, the incremental costs are the differences in the levelized costs of electricity because these renewable electricity sources can substitute for capacity from fossil fuel sources on a one-to-one basis. A pure fuel switching technology like biomass cofiring takes the difference between the levelized costs of cofiring (capital and fuel costs included) and just the coal costs of the power plant because only the fuel is displaced. Intermittent technologies are a hybrid. The model estimates the incremental costs based on any fuel displaced plus any fraction of capacity displaced. Intermittent sources cannot displace capacity on a one-to-one basis but a proportion of capacity can be displaced.

After estimating the incremental substitution costs for each technology, the model aggregates the estimates into a single incremental cost of renewables substitution curve. Figure 9 shows an example of this curve based on one set of parameter assumptions.

Figure 9: Example Incremental Cost of Renewable Substitution Curve Under One Set of Parameter Assumptions



After calculating the incremental costs of renewable substitution and the available capacity for each technology, the figure shows the technologies that comprise the increasing incremental costs of substitution. Biomass supplies electricity in three ways, which is illustrated in the graph. Biofuels refineries can produce excess electricity that is exported to the grid. This is illustrated at the initial portion graph labeled “biofuels coproduction.” The other two biomass renewable electricity sources are dedicated biomass plants and coal plants that mix biomass with coal (biomass cofiring). In this example, geothermal, dedicated biomass, and co-firing have modest amounts of new generation with relatively low incremental substitution costs. Wind has a large amount of available capacity but higher incremental substitution costs, even though in some cases it has lower marginal costs than biomass. Then, there is a significant component of dedicated biomass and cofiring that could come from biomass produced through land conversion, “expensive biomass”. Finally, solar thermal and high-cost wind comprise the last portions of the supply curve in this example. The assumptions used to construct cost curves determine the relative costs and available capacity with each technology, and these assumptions vary in each scenario.

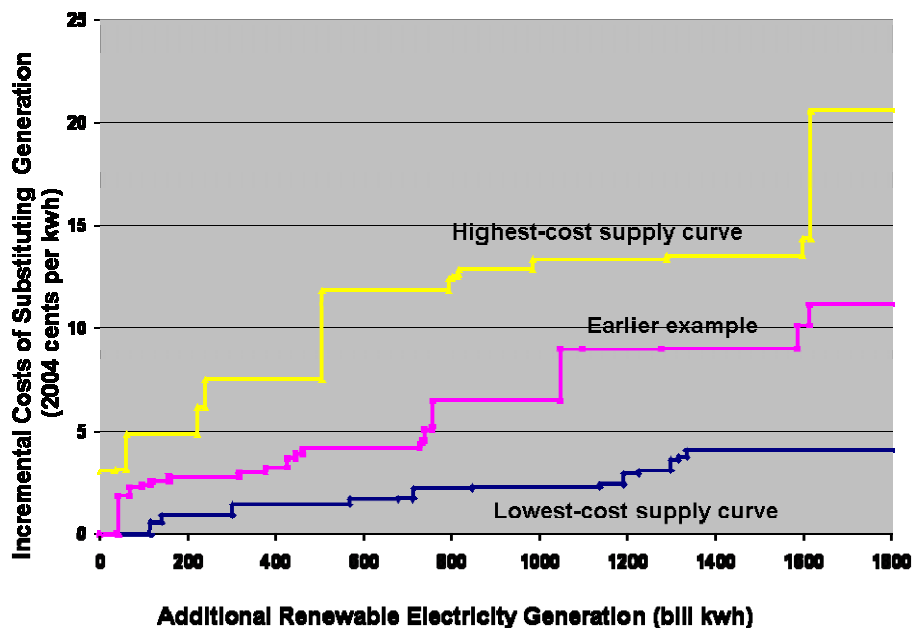
The incremental substitution cost calculation accounts for the ability of a renewable technology to substitute for both nonrenewable capacity and fuel. Because biomass is a firm power technology it directly substitutes for nonrenewable plant capacity and fuel use. Wind is intermittent and fully displaces fuel use but can only partially displace nonrenewable capacity. For these reasons, the firm and intermittent technologies displace nonrenewable capital costs differently.

The cost of producing renewable electricity to meet the requirement is calculated by multiplying the incremental cost of renewables substitution at the point where demand intersects the curve by the net demand for new renewable electricity. In the next step, the model determines how adding renewables changes coal and natural gas prices. The model tracks how renewable energy substitutes for electricity from different fossil fuel power plants. In doing this, it calculates the reduction in demand for coal and natural gas and corresponding drops in their prices, based on simplified supply curve representations of these primary energy resources and nonelectric demand for natural gas. This information is incorporated into the cost of nonrenewable generation and yields a savings for consumers. It also increases the incremental cost of renewable energy.

After determining the expenditure changes for consumers, the model estimates a new average price for electricity. This is a gross simplification of electricity markets, which are a complex mix of competitive and regulated markets at both the wholesale and retail levels. Given the model structure though, it is unable to capture these complexities. With a new estimate of electricity prices, the model calculates any change in electricity demand with a basic equation of energy demand calibrated to EIA data.

Figure 10 illustrates the range of assumptions used in the electricity market.

Figure 10: Range of Incremental Cost of Renewables Substitution Curves



Again, as was true for the fuels market, the upper curve in the figure illustrates the highest-cost assumptions about future renewable electricity technology costs and capacity and the renewable electricity technology costs and capacity and the lower curve shows the lowest-cost assumptions. The curve in the middle represents the example case shown earlier in Figure 9. In this analysis, I vary parameters to construct curves within the range bounded by the two shown in the graph.

The figure shows several important features. In the least-cost case, incremental costs increase very little with additional generation. This occurs because substantial low-cost biomass supplies are available and wind costs grow minimally. In the middle curve, less low-cost biomass is available, and no low-cost biomass or biofuels coproduction are available in the highest-cost case. A second key feature is that wind can provide a large amount of renewable

electricity and that the shape of the incremental cost of substitution curve is largely driven by assumptions about how wind costs rise with capacity increases.

The analysis follows EIA assumptions and uses five cost steps to represent the cost of wind at different levels of installed capacity (shown by the five portions of the two curves labeled wind). These cost escalation factors reflect increasing costs of utilizing wind sites with lower wind quality and additional costs of connecting remote sites to the transmission grid. In the uncertainty analysis, the differences between these cost levels can increase and decrease, which is shown in the graph, and captures uncertainty about the costs of wind power at higher levels of installed capacity. In the bottom curve, wind costs increase much less rapidly than they do in the upper curve. Because wind has much larger potential capacity relative to other renewable energy technologies, this assumption about wind costs has a large influence on the overall shape of the curve.

BIOMASS FEEDSTOCK SUPPLY

Under a 25 percent renewable energy requirement in the motor vehicle transportation fuels and electricity sectors, both sectors compete for a common biomass feedstock supply in a competitive market. Therefore, a critical issue in the analysis is whether sufficient biomass can be grown inexpensively without significant changes to existing land uses. Wastes from agriculture, forestry, and urban areas, as well as from dedicated energy crops can supply biomass for cellulosic ethanol and biomass-to-liquids. In the best case, sufficient waste material exists and dedicated crops can be grown on lands that are not currently in production, and the biomass from these sources can be grown, collected, and transported inexpensively. However, if the amounts of waste material and dedicated crops grown on unused lands are limited, then competition between biofuel refineries and power plants will bid up the price of biomass and induce land owners to convert their land to producing energy crops. Under this scenario, the renewable energy requirement could significantly increase consumer energy costs and have considerable unintended consequences on land and food markets.

A basic example highlights the challenges biomass substitution would pose for the agricultural sector. Using EIA's 2006 projection for fuel demand in the sectors considered in this analysis, a 25 percent requirement entails 51.6 billion gallons of biofuels (in gasoline-equivalent units). Assuming the middle range yield for biofuels (90 gallons per ton of feedstock), meeting this demand with ethanol would require over 850 million tons of biomass

feedstock. This is almost double EIA's 2006 estimate of biomass feedstock supply (433 million tons), but less than the highest estimates near 1 billion tons.

There is currently limited analysis on potential biomass supplies and costs at the scale needed for a 25 percent renewable energy requirement. Several biomass supply curves currently exist. The EIA initially used a set of estimates from researchers at the Oak Ridge National Lab, which they produced in 1999, and had a maximum supply of low-cost biomass at 433 million tons. The EIA recently revised those estimates and now uses a supply curve, which under high yield assumptions has a maximum supply over 700 million tons (Smith, 2008).

Other researchers have assessed the feasibility, but not the cost, of a large-scale biomass supply. A recent joint study with the U.S. Department of Agriculture (USDA) and DOE, known as the "Billion Ton Study," estimated that the U.S. agricultural and forestry sectors can expand to supply over one billion tons of biomass annually without large-scale changes in existing land uses (Perlack et. al., 2005). This amount of biomass is sufficient to supply both the electricity and biofuels markets. However, a key limitation of the study is that it did not estimate the costs of producing this level of biomass.

The estimates above suggest that supplying sufficient biomass is feasible; however, the costs are highly uncertain.¹¹ Achieving a low-cost, large biomass supply will require significant innovation in producing energy crops. If that does not occur, then land use conversion would be needed to meet the requirement, possibly on a large scale.

With this level of uncertainty in the biomass supply and potential cost, identifying a most likely estimate of costs is very difficult. Developing a full-scale model of U.S. land use supply was also beyond the scope of this analysis. Instead, the model represents biomass feedstock supply with three parameters: total supply of low-cost feedstock, distribution of low-cost supply, and cost of biomass from converted lands. It allows for a range of possible values with each parameter.

The total supply of low-cost feedstock represents the amount of biomass available at costs of less than \$90 per ton, and reflects inexpensive biomass supplies from wastes and marginal lands. After the low-cost supply is exhausted, additional biomass comes from lands converted from other land uses and these costs are one of the uncertain parameters. The final parameter is the distribution of feedstock at different cost-levels.

¹¹Other RAND research assessing the *current* costs of delivering biomass for use in a coal-biomass-to-liquids plant showed high costs relative to estimates used in a National Renewable Energy Lab (NREL) estimate of cellulosic ethanol costs conducted in 2002, and the DOE Biomass Program goal for cellulosic ethanol costs.

The low-cost biomass supply varies from 450 million tons to an upper limit of one billion tons. The lower limit is slightly greater than the EIA's older estimate of biomass supply (about 430 million tons), and the upper limit is based on the DOE/USDA Joint Study on the Feasibility of a Billion Ton Biomass Supply. Costs of biomass from converted lands vary from \$90 per ton to \$200 per ton, which reflects differing levels of innovation in biomass production and opportunity costs of land conversion.

OUTCOME MEASURES

Basic economic analysis can broadly characterize the effects of the policy requirement. Overall, the policy would significantly shift the distribution of benefits in the energy market and create dead weight losses that decrease social welfare. First, the policy would compel a shift in the energy supply from fossil fuel energy producers to renewable energy producers. Second, as energy prices rise, energy consumers pay more for energy and lose some consumer surplus. A portion of this surplus change is a transfer to energy producers (both fossil fuel and renewable). Another portion of lost surplus is the deadweight loss created by lower consumption. Both energy consumers and producers bear a portion of this deadweight loss. The magnitudes of each of these effects depend on factors such as the costs of renewable energy, price elasticity of demand, and the institutional design of the policy. The first two effects affect the distribution of benefits in the energy market between fossil fuel producers, renewable energy producers, and consumers. The arguments discussed in Chapter 1 by advocates and critics primarily focus on these distributional issues. The third impact, dead weight losses from reductions in energy consumption, affects the overall economic efficiency the policy. Economists and traditional benefit-cost analyses focus on this result of the policy. Though, the political economy of the renewable energy requirement policy depends largely on the distributional effects of the policy and the relative political clout of the winners and losers. Overall, the 25% requirement would induce a major shift in the energy market and, therefore, the gains and losses by individual groups could be sizeable.

Following from this overview, I use several different outcome measures to characterize the costs and benefits of the renewable energy requirement. The primary cost measures include the change in net energy expenditures, total incremental resource costs, net welfare losses, incremental costs, and surplus transfers. I calculate these measures using basic microeconomic principles that I illustrate in the diagrams below. The models also calculate several measures of

the policy's benefits. These include renewable energy use, reductions in GHG emissions, changes in oil consumption, and savings on oil imports. Finally, I estimate potential changes in land use needed to fulfill biomass feedstock demand. In the diagram below, I illustrate the microeconomic principles used in calculating the cost measures.

Figure 11.A: Example Equilibrium without Renewable Energy Requirement

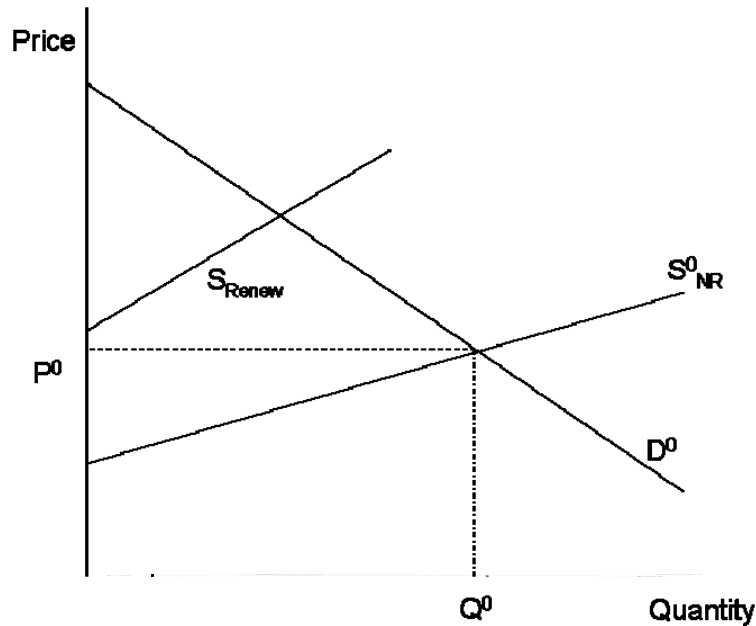
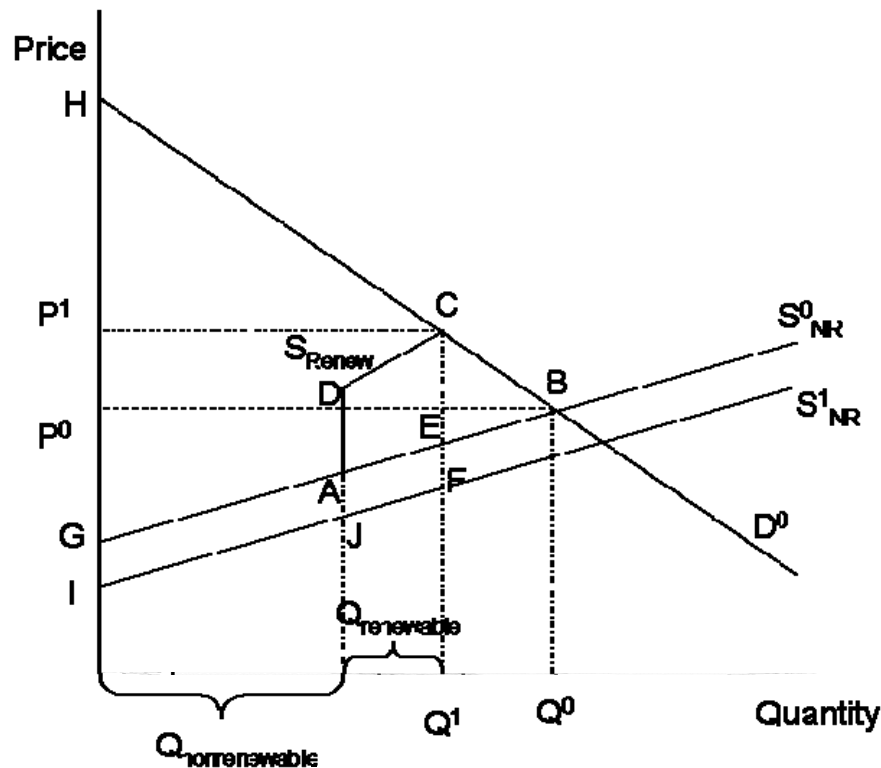


Figure 11.A illustrates the effects of the renewable energy requirement on the energy market. S^0 and D^0 denote initial market demand and supply of energy before any policy requirement. The initial equilibrium occurs at (Q^0, P^0) . For simplicity, I assume that the initial market supply curve, S^0 , consists entirely of fossil fuels, which is actually close to reality in the motor vehicle transportation fuels market. S^1 represents a separate supply curve for renewable fuels with a y-intercept that is greater than P^0 . Therefore, under these assumptions, producers supply no renewable fuels in the initial market equilibrium because the market price is below the marginal costs of producing biofuels.

Now, a 25% renewable energy requirement forces a discontinuity in the supply curve at point A, shown in Figure 11.B. The first 75% of total demand will be supplied by fossil fuels along the initial supply schedule and then the supply curve moves to the schedule for renewable fuels to satisfy the remaining 25% of demand. The new equilibrium point in this market occurs

at (Q^1, P^1) . Evident in the graph, at the new equilibrium the market price increases and demand decreases, which affects consumer expenditures and social welfare.

Figure 11.B: Example Equilibrium with Renewable Energy Requirement



As stated above, the policy requirement forces the market to produce $Q_{\text{renewable}}$ amount of renewable energy, which would not have been produced in the absence of the policy because the initial market price was below the marginal costs of producing biofuels. By including this amount of renewable fuels, the market price increases to P^1 and demand drops to Q^1 . Figure 11.B also shows a shift in the nonrenewable energy supply curve. S^1_{NR} is a new nonrenewable energy supply curve that reflects the lower costs of fossil fuels (a drop in oil prices in the fuels market and a drop in natural gas and coal prices in the electricity market).

The figure shows that the magnitude of the policy-induced changes in prices and consumption depends on several factors: the size of the renewable energy requirement, the shape of renewable energy supply curve, price elasticity of demand, and supply elasticities of fossil fuels. Because the renewable energy supply curve is an increasing function, higher requirements entail higher energy costs and the magnitude of the increase will depend on the

shape of the supply curve. In this basic example, the curve is linear so the key factors are the y-intercept and slope. The figure also shows that the shape of the demand curve affects the outcome. As the price elasticity of demand increases (in absolute value), larger demand decreases occur as the price rises.

This description of the microeconomic effects and illustrations in figures 11.A and 11.B include several simplifying assumptions that aid the interpretation (and simplify the diagram). I made the assumption that all renewable fuels were more expensive than the initial market price and none were included in the baseline energy consumption. In reality, some renewable energy is currently part of the baseline level of consumption, especially for electricity, for several reasons. Some renewable energy, such as hydroelectric power, is currently competitive with fossil fuels. Renewable energy production also occurs in response to the numerous policies discussed in Chapter 1. Many states require certain levels of renewable electricity and the federal government has a renewable fuels standard. The proposal considered in this analysis would increase the levels currently required by law. In addition, numerous economic incentives subsidize renewable energy production. For these reasons, the “pre-policy” baseline for this analysis already includes renewable energy and an important uncertainty is what the baseline level will be by 2025. As described in the Technical Appendix, this analysis assumes the level projected in the AEO 2006, which is a modest increase from today’s level.

A second complicating factor is the pricing rule used to implement the renewable energy requirement. The analysis shown in Figures 11.A and 11.B assumes that fossil fuels will be taxed to the level that equates their costs with 25% renewable energy. This is why the market equilibrium price rises to P^1 under this assumption. Other pricing rules would result in different market prices. Under the subsidy policy, the new market price would occur where the new nonrenewable energy supply curve (S^1_{NR}) intersects the demand curve. Renewable energy production would be greater in this case relative to the fossil fuel tax because of the higher overall level of consumption. The marginal costs of renewable energy would also rise. A final option is a tax-and-subsidy program that taxes fossil fuels and subsidizes renewables. In theory, the market price could lie anywhere between the full tax or subsidy cases depending on the weights selected for the tax on fossil fuels and subsidy for renewables. In this analysis, I assume a revenue-neutral program where the fossil fuel tax revenues exactly pay the renewable energy subsidies. The market price then becomes a weighted average price between the renewable and nonrenewable fuels where the weights correspond to the market shares of the fuels. The electricity market also uses average cost pricing where the price change reflects the net increase

in expenditures to substitute renewable electricity for nonrenewable electricity and the lower expenditures on fossil fuels. This net difference is averaged over the total amount of electricity consumption. For greater detail on these calculations, see the description in the Technical Appendix.

The diagram illustrates how the different pricing mechanisms used to implement the policy requirement can affect the results. The fossil fuel tax raises market prices highest and results in the greatest decline in total energy consumption. These changes affect the total incremental resource costs of the policy, which decline as energy consumption decreases, and the deadweight losses, which increase as the energy consumption declines. As noted in Chapter 3, I have only analyzed implementing the policy requirement through these different pricing mechanisms and other policy instruments could be used. For example, the government could subsidize R&D into renewable energy.

Net Energy Expenditures

The simulation model calculates the change in net consumer energy expenditures and the components for the first portion of this calculation are shown in Figure 11.B. The initial consumer energy expenditure level is $P^0 \times Q^0$ and the new expenditure level is $P^1 \times Q^1$. Thus, expenditure changes are $P^1 \times Q^1 - P^0 \times Q^0$. The diagram also shows that the expenditure change is the difference between the rectangles given by $(P^1 - P^0) \times Q^1$ and $(Q^1 - Q^0) \times P^0$. These rectangles have economic interpretations that also help illustrate the key factors affecting the results. The first rectangle given by $(P^1 - P^0) \times Q^1$ is the additional expenditure induced by higher prices charged on inframarginal consumption. Consumers previously paid P^0 for Q^1 amount of energy and now pay P^1 . This expenditure increase is offset by the decrease in consumption that occurs when prices rise. The change in consumption is given by $(Q^1 - Q^0)$ and consumers initially paid P^0 for this energy consumption and after implementing the policy they no longer pay this amount. The expenditure change is the difference of these two components and the discussion shows the magnitude of the expenditure change is affected by both the price increase induced by the policy requirement and the consumption decrease resulting from higher prices. These two changes are largely determined by the shape of the renewable energy supply and the price elasticity of demand.

This measure includes changes in energy expenditures on electricity and motor transportation fuels plus any government expenditures spent on subsidizing renewable energy. The expenditure also nets out any increases in government revenue from taxes on fossil fuels

(under the relevant pricing policies). The net expenditure change also includes decreases in expenditures on fossil fuels in electricity and transportation markets and in non-electricity and non-transportation consumers of natural gas and oil.

Energy expenditures do not capture any of the potential economic inefficiencies of a renewable energy requirement or the changes in social welfare. Furthermore, this measure includes transfers from consumers to producers that are likely to occur as energy prices rise. For instance, the rectangle given by $(P^1 - P^0) \times Q^1$ is an increase in expenditures for consumers and some of this additional expenditure pays the resource cost for renewable energy, but most of the increase is a transfer of surplus from consumers to energy producers. While these higher expenditures may be unpopular with consumers, from a societal perspective the only change in welfare from the higher expenditures is the additional resources spent to produce renewable energy.

In the results displayed in Chapters 3 and 4, I have not included net energy expenditure change calculations and instead focus on one of the main contributions of this study, which is estimating the social welfare effects of the policy requirements. Readers interested in the net expenditure implications of a 25 x 25 policy requirement should see Toman et al. (2008).

Change in Social Welfare

The change in social welfare has two main components within the markets for electricity and motor vehicle fuels. These are the total incremental resource costs of using renewable energy instead of fossil fuels and the deadweight losses from lower energy consumption. Additional welfare changes also occur in the markets for primary fuels. As prices for feedstock change (fossil fuel prices drop and corn prices rise), consumers outside the electricity and motor vehicle transportation fuels markets change their consumption. The models also calculate the gain or loss of consumer surplus from these effects.

I first illustrate the welfare changes in the end-use markets directly affected by the policy requirement. Using Figure 11.B, the initial consumer surplus is given by the triangle HP^0B and producer surplus is the triangle GP^0B . After implementing the policy, consumer surplus decreases to HP^1C and producer surplus becomes the polygon given by $IJDPC^1$. Following from this, the change in social welfare is given by the quadrilateral, $ABCD$. This quadrilateral can be decomposed into a triangle, EBC , and quadrilateral, $AECD$, which each have an economic interpretation. Triangle EBC is the dead weight loss that occurs from reduced energy consumption. The quadrilateral $AECD$ is incremental resource costs of using renewable energy

instead of fossil fuels to satisfy the amount of energy consumption given by $Q_{\text{renewable}}$. These incremental resource costs were previously surplus enjoyed by consumers and profits for energy producers. The relative incidence of the welfare losses depends on the shape of the renewable energy supply curve and elasticities of the demand and supply curves.

The fuels market contains an additional welfare change not shown in the graph. Adding renewable fuels to the fuel supply decreases demand for oil and the world oil price declines. The lower oil prices transfer surplus between producers and consumers, which is described in more detail below. However, there is one exception. The decline in foreign producer surplus captured by domestic oil consumers is a net gain in social welfare from the U.S. perspective. The oil supply model calculates the change in oil prices and estimates the demand for U.S. imports after a decline in oil demand. In the electricity market, increasing renewable electricity decreases demand for coal and natural gas, and lowers prices for the fuels for electric and non-electric consumers. I also calculate the consumer surplus gain from lower natural gas prices. I only estimate this effect for natural gas because non-electric sector coal consumption is currently a small component of total coal demand.

A final social welfare change occurs in the market for corn. In Chapter 4, I analyze several strategies that allow unconstrained corn ethanol production. I calculate the change in corn prices and the resulting decrease in demand for non-ethanol corn consumers. Of note, the social welfare calculations in the feedstock markets only capture the consumer surplus change resulting from changing consumption. The increases or decreases in spending on inframarginal consumption are transfers of surplus, and these are the next outcome measure I discuss.

Surplus Transfer between Producers and Consumers

When fossil fuel prices decline, producers earn lower profits on inframarginal units of demand and consumers gain surplus when consuming these units of energy at lower prices. Of note, surplus transfers occur in two different markets. The first is the market for energy end-uses (electricity and motor fuels); the second market is for primary fuels (oil, natural gas, coal, and corn). Figure 11.B shows this surplus transfer for motor vehicle transportation fuels producers. The quadrilateral AGHI reflects the lower price of oil that refiners purchase from oil producers. In this market where refiners are oil consumers and transportation fuel producers, the policy requirement lowers oil producer profits while increasing oil refiner profits. The model also makes a similar calculation for corn surplus transfers as corn ethanol production raises corn prices. Finally, as noted above, I net out the surplus transfer from foreign oil

producers and domestic oil consumers because this change in surplus is actually a social welfare change.

Incremental Costs of Policy Requirement

The model also estimates the incremental cost of renewable energy. The measure is the difference in energy costs between the marginal renewable energy resource used to satisfy the 25% requirement and the cost of the conventional energy source displaced. In Figure 11.B, this cost is shown by the line segment CF. This measure indicates the additional costs of the policy requirement at the margin and is useful to compare the cost-competitiveness of this policy with other policies with the same objectives.

I also calculate a variation of this measure, which is the incremental cost per GHG reduction. This measure is the ratio of the cost difference described above and the difference in GHG emissions of the renewable energy and conventional energy sources. The incremental cost per GHG reduction can be compared across markets to judge the cost-effectiveness of reaching 25% renewable energy in both markets. For instance, if the costs deviate substantially across markets then varying the percentage requirements (higher percentage in the lower-cost market and lower percentage in the higher-cost market) could result in equivalent or potentially higher emissions reduction at lower cost. However, a problem with this comparison in this particular policy is that GHG reductions are one of several potential benefits and this measure implicitly attributes the entire cost of the policy to one benefit. This is an important issue when comparing incremental costs across the electricity and fuels markets. Increasing renewable energy reduces oil consumption in the fuels market; however, higher renewable energy in the electricity market has little effect on oil consumption because the U.S. uses very limited amounts of oil for electricity. Finally, the incremental costs of GHG reduction can be used to judge the cost-competitiveness of this policy requirement with other policies and technologies that reduce GHG emissions with the same caveat discussed above on multiple benefits.

Greenhouse Gas Emissions

Reductions in greenhouse gas emissions are one of the important benefits of the policy requirement and the reductions result from two effects. The first is substitution of renewable energy for fossil fuels. The model estimates how renewable energy displaces fossil fuels and calculates changes in CO₂ emissions based on literature estimates of the lifecycle emissions from the various renewable and nonrenewable technologies. A second source of emissions reductions

is the conservation effect (demand reduction) that occurs energy prices increase and consumption decreases. In some scenarios where renewable energy at the 25% level is costly, this conservation effect becomes substantial.

Oil Consumption

A second important benefit from the policy is reducing oil consumption, which is assumed to occur only in the motor vehicle transportation fuels market (oil is a small portion of electricity generation). Again, the model calculates both a substitution effect and conservation effect as biofuels replace petroleum based fossil fuels.

Land Use Change

Another outcome metric calculated in these models (not shown in the diagrams above) is additional land use change required to supply total biomass feedstock demand. Biomass feedstock is assumed to come from two sources. Low-cost feedstock is supplied from wastes and marginal lands. The total supply of this feedstock is a parameter in the model. Any additional biomass required to meet the 25% requirement is assumed to come from converting crop or pasture land into producing energy crops. The model estimates the amount of land conversion using a constant yield of 7 tons biomass feedstock per acre.

The outcome measures described above and used in the analysis are not an exhaustive set of metrics. The cost measures capture many important economic effects of the policy but do not include macroeconomic consequences, such as changes in GDP, net employment, and per capita income. In addition, the present analysis does not estimate potential environmental damages from local increases in water pollution or water consumption. The benefit metrics do not capture potential improvements in criteria pollution emissions in urban areas or spillover effects of innovation in energy technologies into other sectors of the economy. By excluding these outcomes, I am not implicitly minimizing their importance. Measuring these effects would require additional models that were beyond the scope of this analysis.

APPLICATION OF ROBUST DECISION-MAKING ANALYTICAL METHODS TO 25 X 25 POLICY REQUIREMENT

Earlier in this chapter, I described five steps in robust decision-making (RDM) analyses in general terms, and I now provide a detailed description of how I apply these methods to the 25 x 25 policy requirement.

Identify Initial Candidate Strategy

For the initial strategy in this analysis, I require each market to achieve 25% renewable energy without any contingencies if costs exceed expected levels or substitute for renewable energy using alternative GHG- and oil-reducing technologies. The initial strategy also restricts corn ethanol production at 12 billion gallons, which I drew from EIA's AEO 2006 assumptions about biofuels production. Even though EIA revised this assumption in recent analyses, as an initial assumption it is not unrealistic given constraints on corn ethanol in current renewable fuels standard legislation (15 billion gallons). I also relax this constraint in alternative strategies analyzed later. The initial strategy also utilizes the revenue-neutral tax-and-subsidy pricing mechanism in the transportation fuels market. However, I also compare results using the fossil fuel tax. I have not used the subsidy pricing mechanism based on results in Toman et al. (2008), which showed the subsidy mechanism generally resulted in the most costly outcomes when renewable energy at the 25% level is expensive.

In Chapter 3, I present results from exploratory analysis on the initial strategy. The exploratory analysis assesses this strategy across the range of uncertainties in energy markets captured in the input variables. To perform the exploratory analysis, I generate a sample of 250 sets of input values using the Latin Hypercube sampling method and evaluate the models with these values. The Latin Hypercube method samples quasiuniformly over the space of input values; however, in using this method, I do not imply that the input variables have uniform probability distribution functions (PDFs). Rather, I use this sampling method because the underlying PDFs of the input variables are unknown, and the method efficiently samples the broad range of potential outcomes with a limited number of points.

Identify Vulnerabilities

In performing the exploratory analysis on the initial strategy, I generate a range of plausible outcomes for the policy requirement. A traditional analysis would assign probabilities

to the input variables and calculate the expected outcome of this strategy. For the reasons noted earlier, I selected RDM methods for the uncertainty analysis and in the next step of this analysis I define thresholds that would potentially change a decision-maker's choice about the policy requirement. One threshold is a low-cost outcome where the policy imposes limited costs on society and yields large benefits. Under this outcome, the majority of the public is likely to support the policy requirement. The second threshold is a high-cost cost outcome where the opposite occurs. The policy requirement incurs large costs and becomes highly unpopular with the public. In these outcomes, decision makers would likely prefer to adjust or remove the policy requirement. Based on these definitions, I categorize the outcomes into each group, and analyze the key factors associated with each of the outcomes.

To assess key factors, I use scenario discovery analysis, which employs a data mining technique to identify the key input variables associated with the low-cost and high-cost outcomes in the range of results. The scenario discovery analysis also identifies range of the input variables associated with these outcomes. This step of the analysis typically reduces the problem from many dimensions to a limited set, and in doing so simplifies a complex problem. For instance, the electricity market model has 13 input variables representing uncertainties in future energy markets and the fuels market has 15 input variables. The scenario discovery analysis generally finds 2-3 key factors that best explain the outcome, and these key factors are not always clear before the analysis. Furthermore, the analysis defines the range of these unknowns that are important to the outcome. Finally, by reducing the dimensions of the decision problem, the analyst can typically describe the key factors with a qualitative description, which is useful in explaining the analysis to a non-technical audience.

Suggest Hedges Against Vulnerabilities

The analysis of the initial strategy's vulnerabilities in Chapter 3 suggests new strategies that may address the weaknesses of the initial strategy. Chapter 4 analyzes five additional strategies that attempt to overcome the vulnerabilities of the initial strategy in two ways: additional resources qualifying towards the policy requirement and a limit on costs. I use strategies that allow additional corn ethanol and energy efficiency to qualify towards the 25% requirement. These are potentially low-cost resources and in commercial use today. By including them in the policy requirement, they can possibly lower the costs of reaching the 25% requirement, particularly in scenarios with high costs for the other technologies. A second option included in the alternative strategies is a safety valve that allows refiners and utilities to

pay the government a fixed fee in lieu of producing additional renewable energy. The safety valve sets a certain cost ceiling for the policy requirement.

Characterize Deep Uncertainties and Trade-offs Among Strategies

In Chapter 4, I display results for each strategy for the outcome measures discussed in the previous section. I show how each strategy can reduce the policy's costs relative to the initial strategy, and any potential trade-offs with other policy objectives. In the later portion of the chapter, I characterize three broad scenarios for future renewable energy costs that explain the results in the analysis, and I compare how each of the strategies perform across these scenarios. I then conclude which strategy is robust to these uncertainties.

Consider Improved Hedging Options and Surprises

In the process of generating the strategies and results seen in this document, I iterated through the steps described above multiple times. I started by analyzing individual strategies that only included one additional resource to qualify towards the requirement, and then tested different combinations. I also tested a strategy that used a carbon-intensity requirement instead of a percentage renewable energy requirement. I eventually dropped this strategy because it had limited effect on reducing the risk of high-cost outcomes, which as the results in Chapter 3 and 4 show is the primary vulnerability of the policy. However, the strategy did marginally improve the cost-competitiveness of the policy requirement, because it discouraged resources with high incremental costs of GHG reduction.

This method of analysis differs from previous analysis on renewable energy requirements and energy policy analysis more broadly. In the studies reviewed in Table 2 of Chapter 1, most of the studies analyzed one future scenario and one strategy for implementing the policy requirement. There were exceptions. EPA (2007) performed some sensitivity analysis of their results to assumed corn ethanol costs. EIA (2007c) assessed the 25 x 25 policy under 4 different scenarios that varied assumptions about technological progress, fossil fuel prices, and availability of ethanol imports from Brazil. In these studies, the analysts defined the scenarios through their choice of parameter values. Kann and Weyant (2000) note this type of scenario analysis as very common in energy policy analysis, and a key weakness is that the analysts may miss scenarios that have important or surprising outcomes. In this analysis, the analyst defines the range of input variables and outcomes of interest, which requires careful

judgment. However, the scenarios leading to the outcomes of interest emerge from the results. The scenario discovery analysis identifies the key factors that best explain the outcomes. Often, this method finds scenarios that were not apparent before the analysis. Even for more obvious scenarios, the method determines the ranges for important unknowns instead of the analyst selecting certain values.

Finally, the decision criterion of robustness used in these methods of decision analysis contrasts sharply with the optimality criterion typically used in energy policy analysis. Kann and Weyant (2000) surveyed the differing approaches to uncertainty analysis in energy-economic models and found that maximizing expected utility was central to nearly every study. As noted earlier, in problems of deep uncertainty many of the important components of the decision problem are unknown or controversial, which poses problems for calculating expected utility. In choosing robustness as a criterion, a particular decision may not be optimal for any given state of the world but the goal is to find a decision that is close to the optimal state across all of the uncertainties.

This chapter described deep uncertainty and the analytical methods of robust decision-making first in general terms and then I discussed how I used these methods in this particular analysis. I also explained how I implemented a 25 x 25 policy requirement and the simulation models used in the analysis. Finally, I described the outcome measures that quantify the policy's costs and benefits, and the microeconomic theory underlying these measures. In the next chapter, I show the results from implementing the policy requirement using the initial strategy.

CHAPTER 3: EFFECTS OF 25% REQUIREMENT UNDER INITIAL STRATEGY

This chapter displays the research findings under the first three research questions described in the Objective section of Chapter 1. The analysis shows the potential costs and benefits of the 25 x 25 policy requirement under the initial strategy and describes the sets of conditions where it leads to low-cost and high-cost outcomes. I then look at the cost-effectiveness of a fixed 25% requirement in both markets and its cost-competitiveness with other policies and technologies that also lower GHG emissions.

FINDINGS UNDER RESEARCH QUESTION #1

What are the potential implications of a 25% renewable energy requirement in electricity and motor vehicle transportation fuels by 2025 for overall economic well-being (consumer plus producer surplus) and U.S. greenhouse gas emissions, under the broad range of uncertainties affecting energy markets?

When using the initial strategy to implement the policy, I find the following implications of a 25% renewable energy requirement:

- substantial variation in all cost measures across different sets of assumptions, especially in the motor vehicle transportation fuels market;
- costs to achieve 25% renewable energy are generally higher in the motor vehicle transportation fuels market;
- 25% requirement reduces CO₂ emissions significantly;
- large surplus transfers from fossil fuels producers to consumers;
- significant economic rents earned by biomass producers; and
- potentially large unintended consequences in land markets can occur, if biomass is scarce.

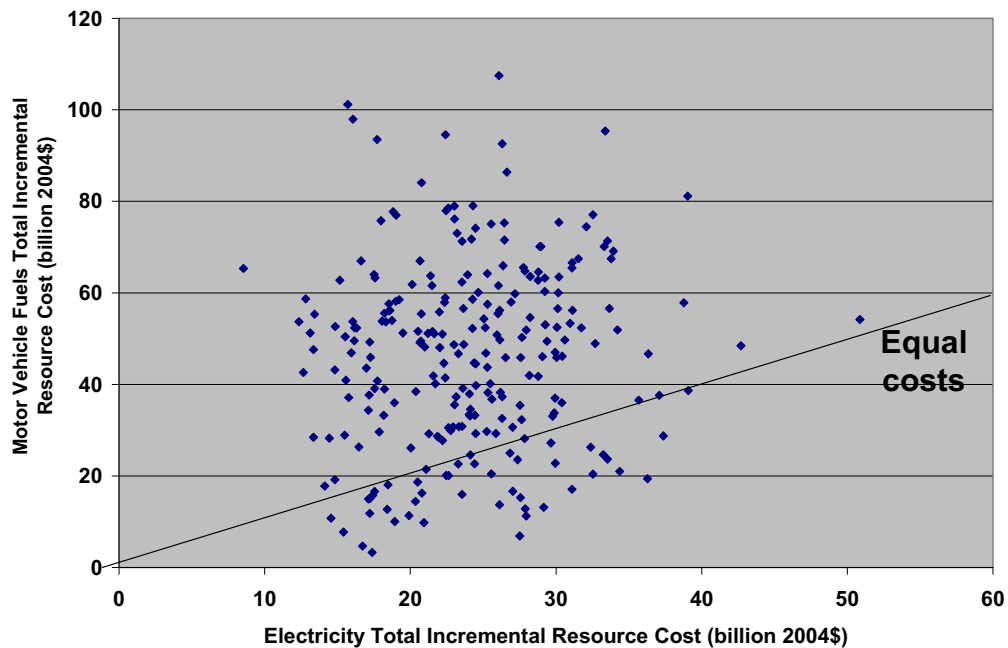
Costs Vary Substantially in Both Markets but Generally Higher for Biofuels

In this section, I show the cost results for the initial strategy, which includes total incremental resource costs, net welfare losses, average welfare loss, and incremental costs. As

noted in the final section of Chapter 2 on outcome measures, each cost measure assesses different aspects of the policy's effects on consumers and producers. The results show that costs vary substantially in all the measures, and this section begins with the results for the total incremental resource cost measure.

The total incremental resource costs are the aggregate incremental costs of the new renewable energy produced to meet the 25% requirement. This cost is the sum of the area under the renewable energy supply curve but above the nonrenewable supply curve, and measures the additional labor and capital costs incurred to produce 25% of energy demand from renewable energy sources. I present these costs first because they are the largest component of the overall welfare change and do not contain any offsetting effects like deadweight losses in transportation fuel markets and surplus gains for non-transportation oil consumers. Figure 12 shows the total incremental resource costs for both the electricity and motor vehicle transportation fuels markets.

Figure 12: Range of Total Incremental Resource Costs in Each Market

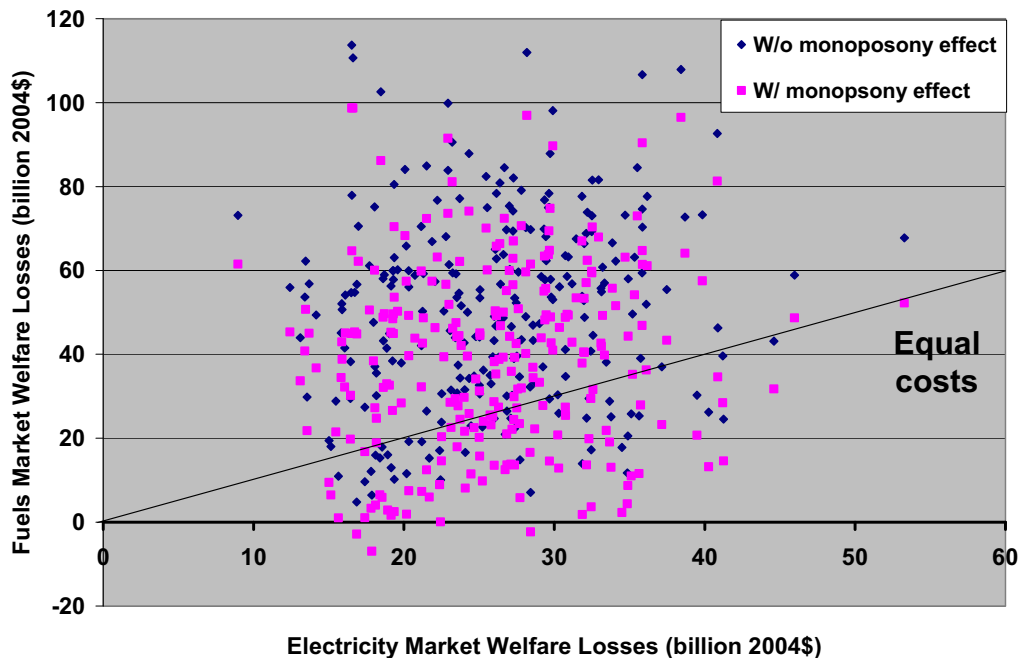


The figure shows total incremental resource costs for electricity on the horizontal axis and the vertical axis displays the estimates for the fuels market. The graph shows that costs vary

considerably in both markets, but the range of outcomes is higher in the fuels market. Furthermore, the costs of individual scenarios are also generally greater in the fuels market. The line in the graph shows the points where costs are equal in both markets. For all of the points above the line, the costs in the transportation fuels market exceed the electricity market, and 83% of the outcomes occur in this region. The total incremental resource costs in the electricity market range from \$9 billion to over \$51 billion (2004\$). In the motor vehicle transportation fuels market, total incremental resource costs vary from \$3 billion to \$107 billion (2004\$). The figures reflect the increase in 2025 steady state costs after implementing the policy and do not include the transitional costs as the policy is implemented.

I now present results for total welfare losses which include the total incremental resource costs from increasing renewable energy but also add deadweight losses from lower energy consumption and any additional changes in consumer surplus in primary fuels markets(both increases and decreases) as the price of feedstocks change (natural gas, coal, oil, and corn). A second effect is the reduction in U.S. consumer spending on oil imports (the monopsony effect). This lower spending is a net welfare gain for U.S. consumers. In Figure 13, I show two sets of results the first set displays the welfare losses in each market not including the monopsony effect and the second set shows the net welfare losses including this benefit.

Figure 13: Range of Welfare Losses in Each Market



Again, the horizontal axis displays the results for the electricity market while the graph shows the fuels market on the vertical axis. In the electricity market, which does not involve the monopsony effect, welfare losses span from \$9 billion to \$53 billion. In the fuels market, the range of welfare losses when excluding the monopsony effects varies from \$5 billion to \$114 billion, and welfare losses exceed the electricity market in 82% of the scenarios. When including the monopsony effect, the losses in this market range between -\$7 billion and \$99 billion, and the percentage of scenarios with welfare losses higher than the electricity market declines from 82% to 68%. The monopsony effect lowers welfare losses in the fuels market from \$7 billion to \$17 billion. In a few scenarios, the monopsony effect more than offsets the higher costs of renewable fuels.

As noted above, this net welfare loss measure also includes the deadweight losses from higher electricity and fuels prices but these costs are relatively small compared to the resource costs. The deadweight losses in the electricity market vary from \$0.1 billion to \$9 billion. The range of deadweight losses in the fuels market is generally greater than the electricity market and varies from \$0.1 billion to \$22 billion, which indicates the greater relative increase in fuels prices. A final impact in the net welfare loss measure is consumer surplus gains for non-electricity and –fuels consumers of fossil fuels. Surplus increases for non-electric natural gas consumers from lower natural gas prices range up to \$1.2 billion. The surplus increase for non-transportation oil consumers ranges from near zero up to \$0.2 billion. An important note is that these surplus increases are the value of new consumption induced by lower prices and do not include the inframarginal savings from lower prices. I show the surplus transfer results shortly.

Decision makers and consumers may not find the aggregate welfare loss measure easy to interpret and weigh relative to other social goals. The losses are very large in absolute terms but relatively small when compared to GDP or total energy expenditures. To help interpret the results, I also calculate an average cost measure that is the total welfare losses divided by the total energy consumption in each scenario. The average cost measures the additional costs to society of the 25% policy requirement spread over the energy consumption in each market. However, the key groups affected by the policy do not bear the costs evenly, which is important to consider when viewing the results. Energy consumers bear most of these costs and fossil fuel producers also incur a portion. Furthermore, the incremental costs of the 25% requirement are larger than the average costs, potentially much larger in many scenarios. Nevertheless, the average costs of the policy requirement are still a useful metric for comparison because they

normalize the costs by energy consumption, which varies across the results, and use units that are familiar to decision makers and energy consumers.

Finally, in Figure 13 I separated the results by the monopsony effect to highlight the size of this benefit and its effect on reducing welfare losses. In the remainder of the results, I only show the estimates including the monopsony effect.

Figure 14: Average Welfare Losses in Each Market

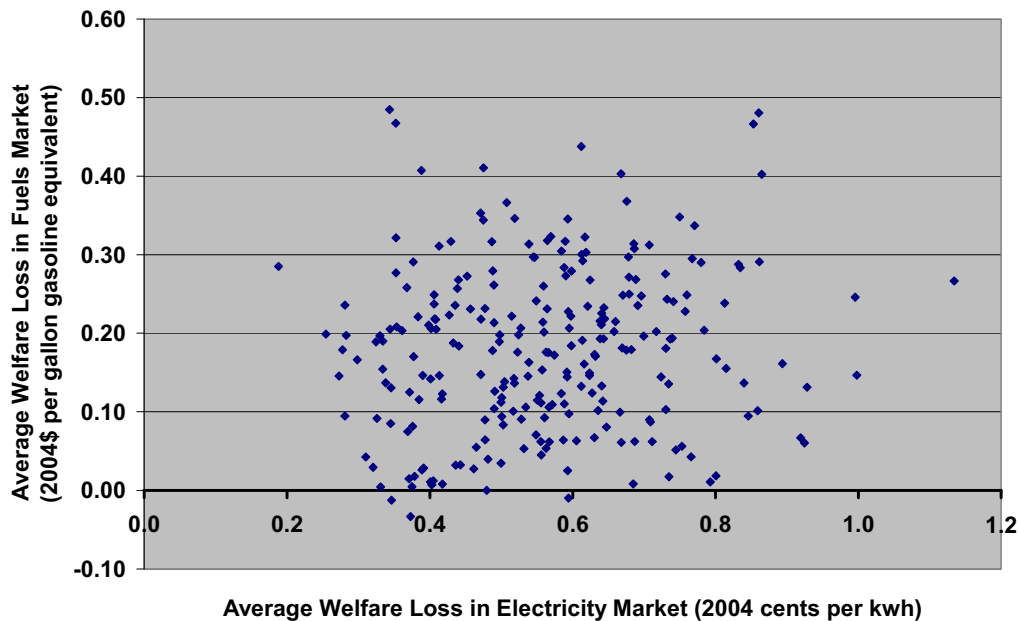


Figure 14 shows the average welfare loss in the electricity market on the horizontal axis in units of cents per kwh. The vertical axis shows these costs in the fuels market in units of \$ per gallon gasoline equivalent. Average costs of policy in the electricity market range from 0.2-1.1 cents per kwh while these costs in the fuels market vary from -\$0.03-\$0.48 per gallon gasoline equivalent. These costs are an increase over baseline average prices from 3%-15% in the electricity market and -1% - 23% in the fuels market.

The average welfare loss is useful for comparison but it can conceal high incremental costs when renewable energy has increasing marginal costs (as assumed in this analysis). Figure 15 displays estimates of the incremental costs in each market.

Figure 15: Incremental Renewable Energy Costs in Each Market

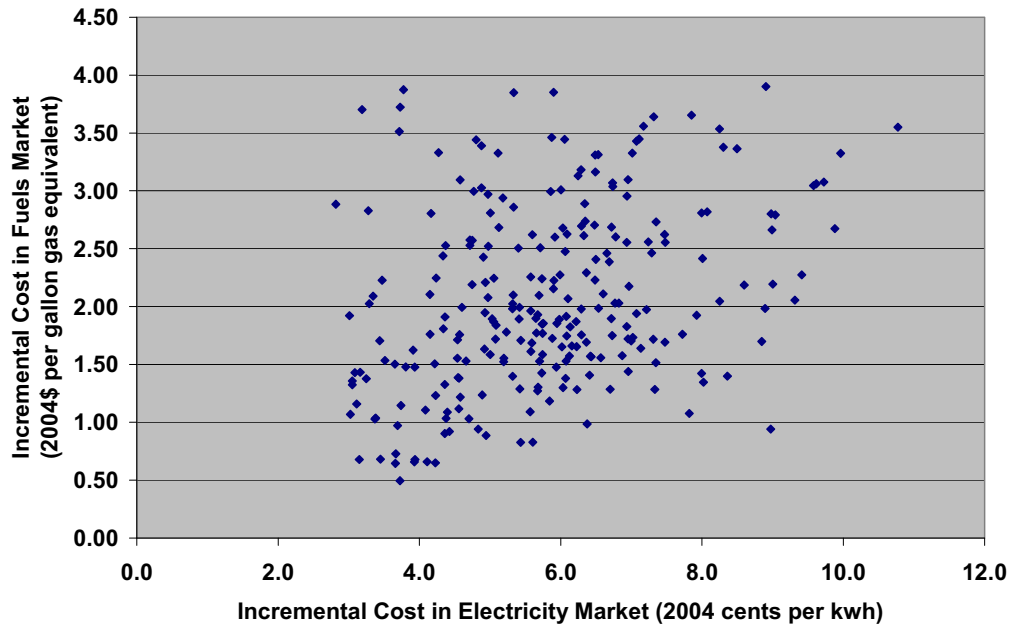


Figure 15 shows the additional costs of the marginal renewable energy source that satisfies the 25% requirement over the costs of the fossil fuel alternative. For instance, if the cost of cellulosic ethanol at the 25% level is \$5 per gallon and gasoline costs \$4 per gallon, then the incremental costs of the 25% requirement are \$1 per gallon. The horizontal axis shows the incremental costs in the electricity market in units of cents per kwh and the vertical axis shows the estimates for the fuels market in units of \$ per gallon gasoline equivalent.

The graph shows high incremental costs in both markets. In numerous scenarios, incremental costs in the fuels market exceed \$3.00 per gallon and over 8 cents per kwh for electricity. These incremental costs are substantial increases over the baseline prices assumed for gasoline and electricity drawn from EIA's AEO 2006 Reference case (\$2.13 per gallon of gasoline and 7.4 cents per kwh). The range of values represents increases of 39%-150% in the electricity market and 23%-183% in the fuels market.

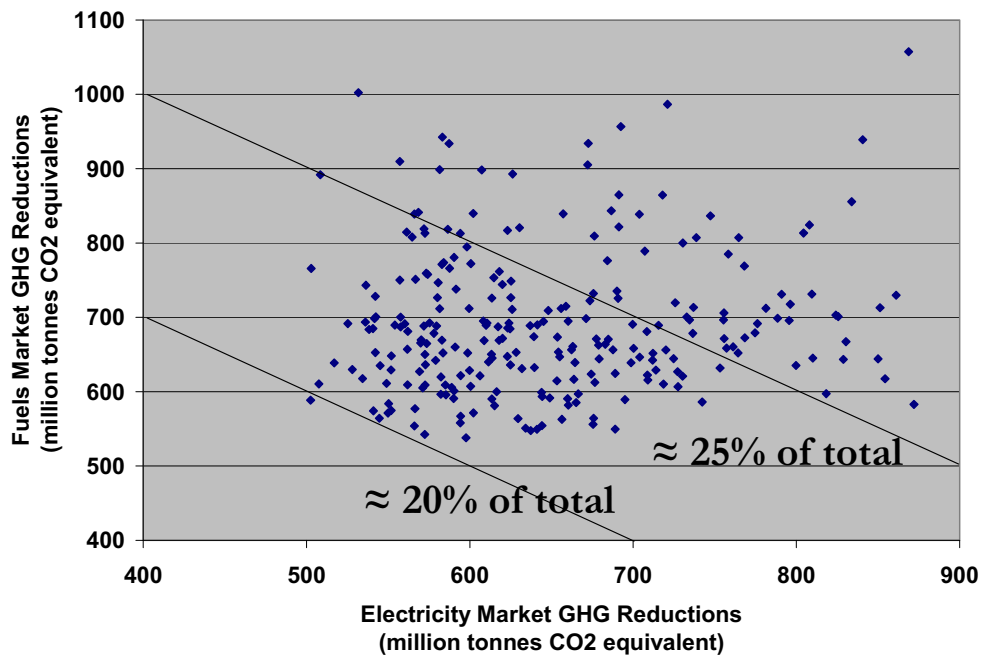
An important note is that this metric is sensitive to assumed level of fossil fuel prices. To establish a baseline for the estimates, this analysis benchmarked the estimates of 2025 fossil fuel prices and power plant construction to the EIA's AEO 2006 projection and has limited ability to vary fossil fuel prices. The AEO 2006 baseline prices are low when compared to today's market where oil prices remain above \$100 per barrel. Higher fossil fuel prices would reduce these

incremental costs; however, even with high oil and gas prices, large incremental costs are still possible. For instance, if 2025 gasoline prices were \$4 per gallon (about \$2 per gallon higher than the projected price), the incremental costs in the high-cost cases would still approach \$2 per gallon.

25% Requirement Reduces Greenhouse Gas Emissions Significantly

The previous sections displayed several measures of the policy’s costs and showed they vary considerably with possibly substantial costs in many scenarios. The 25% requirement can also reduce greenhouse gas emissions significantly. Figure 16 shows the range of GHG reductions in the electricity and motor fuels markets.

Figure 16: Range of Greenhouse Gas Reductions in Both Markets



The horizontal axis shows greenhouse gas emissions for the electricity sector in units of million tonnes (metric tons) CO₂ equivalent and the vertical axis displays reductions for the fuels market in the same units. EIA’s AEO 2006 projects total electric utility and transportation sector emissions in 2025 at 5614 million tonnes CO₂ equivalent. The chart shows total emissions reductions almost always exceed 20% of the projected emissions from these sectors and many scenarios reduce emissions by more than 25%. Of note, this analysis only considers a

subset of the transportation sector. Energy use in other significant transportation sectors such as air and marine transportation was excluded from the requirement but included in the total sector emissions shown above. The EIA does not disaggregate the GHG emissions within the transportation sector and I could only use the estimate for the entire sector. Therefore, the percentage change in emissions from the sectors included in the analysis is actually greater than the values shown in the labels.

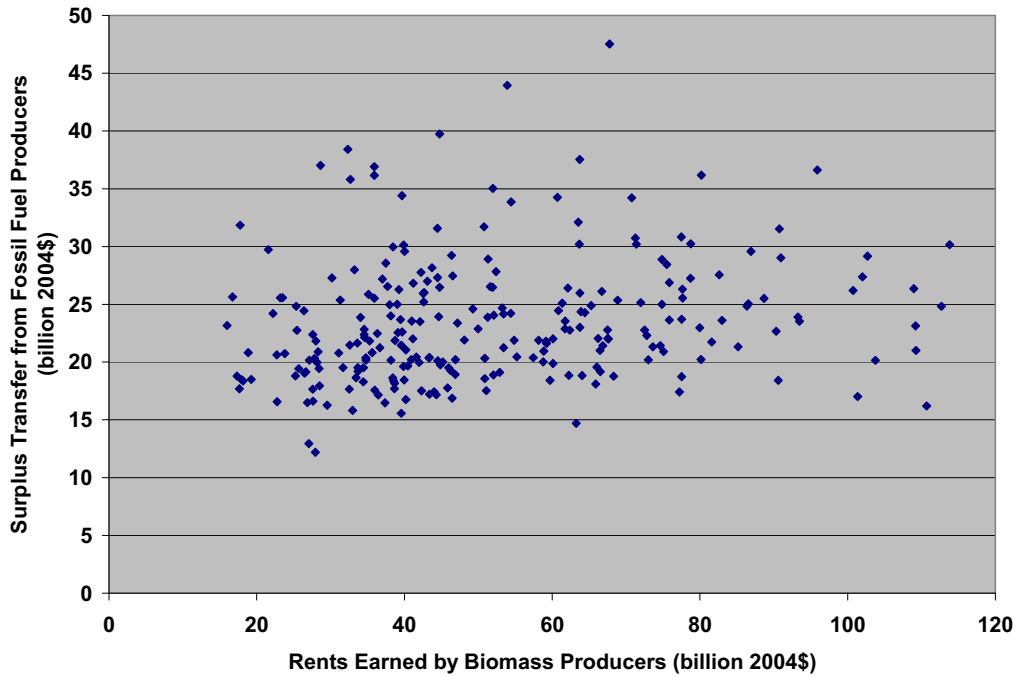
The policy requirement reduces GHG reductions for two reasons. The first reason is a substitution effect where renewable energy substitutes lower carbon-intensity fuels for higher carbon-intensity fuels, which decreases emissions. The second reason is a conservation effect where higher energy prices reduce energy demand, which also lowers emissions. In many of the costly scenarios, the policy requirement increases prices considerably and causes a large conservation effect with significant GHG reductions.

At this point, I've shown the net welfare losses from the policy requirement, which excludes any surplus transfers between consumers and producers for inframarginal consumption. The policy requirement reduces prices for fossil fuels, and while the price changes are relatively small in most scenarios the U.S. is a large consumer of fossil fuels and the aggregate transfers are large. The next section describes these effects.

Policy Transfers Surplus from Fossil Fuel Producers to Consumers and Generates Rents for Biomass Producers

Figure 17 displays the surplus transfers for fossil fuels and rents earned by biomass producers. The fossil fuel transfers include the markets for oil, natural gas, and coal, but net out the monopsony effect in the oil market. These distributional changes are critical to understanding the political economy of the policy requirement and the results show that the distributional changes are considerable.

Figure 17: Surplus Transfers from Fossil Fuel Producers and Rents Earned by Biomass Producers



The horizontal axis shows the surplus earned by producers of biomass feedstock. This surplus is profit earned on inframarginal supplies of biomass feedstock and is a transfer from energy consumers. The vertical axis displays the surplus transferred from fossil fuel producers to consumers, which occurs as the prices of oil, natural gas, and coal decline under the policy requirement. Fossil fuel consumers benefit from the lower prices while they are a loss to producers.

As the graph shows, the gains and losses are substantial in the markets for fossil fuels and biomass. Biomass producers gain considerably because the policy requirement induces an immense increase in demand for biomass feedstock, primarily to produce liquid fuels but also for electricity. In many scenarios, the large increase in biomass demand results in feedstock prices well above \$100 per ton, which is very profitable for low-cost biomass feedstock producers that can produce feedstock at costs of \$40-\$50 per ton (the range of prices where a majority of low-cost feedstock becomes available in the supply curves used in this analysis). The surplus gain for biomass producers is primarily a transfer of consumer surplus from energy consumers (mostly transportation fuels consumers) that occurs as energy prices rise to bring 25% renewables into the electricity and motor vehicle fuels markets. The majority of scenarios

create rents for biomass producers between \$20 and \$60 billion but the graph shows numerous scenarios in excess of \$100 billion.

For fossil fuel producers, renewables substitution decreases prices only a limited amount; however, even small price declines translate into large transfers because the U.S. is a large consumer of fossil fuels. In the majority of scenarios, the policy induced transfers between \$15 and \$30 billion but fossil fuel surplus transfers did extend to almost \$50 billion. In most scenarios, oil and natural gas producers comprise approximately 80%-90% of the fossil fuel transfer. The surplus transfers in the coal market were smallest because coal is assumed to have a more elastic supply curve resulting in lower price declines as coal demand decreases from substituting renewable energy.

Surplus transfer results illustrate the arguments discussed in Chapter 2 by advocates and critics of renewable energy requirement policies. Biomass and renewable energy producers are vigorously promoting these policies based on the employment and economic benefits from increasing use of renewable energy. The estimates of total incremental resource costs quantify the additional spending on labor and capital for renewable energy, which translates into increases in employment, construction, and manufacturing activity in this sector. Furthermore, the estimates of biomass rents indicate producers stand to earn very large profits in many scenarios. These results show that the advocates are correct in their assessment that the policy requirement will stimulate employment and economic activity in this sector; however, these gains come at the expense of fossil fuel producers and energy consumers.

Fossil fuel producers will lose potentially significant amounts of revenue through lower prices on remaining consumption, production lost through renewable energy substitution, and lower overall sales as higher prices induce lower consumption. All of these effects will reduce employment and profitability in this sector. Energy consumers will face higher prices under all of the scenarios in this analysis and a portion, sometimes sizeable, of the higher expenditures involves surplus transfer to renewable energy and biomass producers.

Given these effects, the vigorous lobbying by both renewable energy and fossil fuel producers is not surprising. Renewable energy producers stand to gain considerably at the expense of fossil fuel producers. Consumers are then a key group in garnering political support or opposition for the policy requirement. Consumers are a more diffuse group and harder to organize; however, if the requirement becomes costly then broad-based consumer opposition is likely. Finally, the significant amounts of surplus transfer indicate that enacting and sustaining

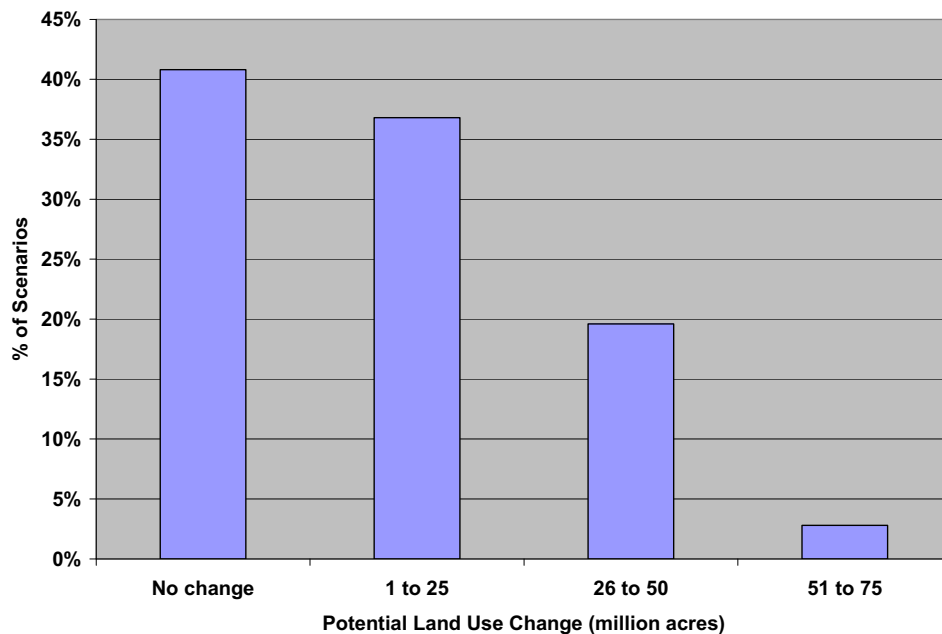
a national-level 25% renewable energy requirement will require significant political capital to overcome the opposition by fossil fuel producers that lose surplus from the policy.

Large Unintended Consequences in Land and Food Markets, if Biomass Scarce

A 25 percent renewable energy requirement for electricity and motor vehicle transportation fuels would spur a massive expansion of biomass supplies beyond current levels of production. In the motor vehicle transportation fuels market alone, biofuels would need to expand production by more than 10 times from current levels¹².

As discussed in Chapter 2, this analysis assumes biomass feedstock comes from two types of supply. Low-cost feedstock includes wastes from other processes and biomass grown on marginal lands that would not be in production otherwise. After exhausting this supply, producers supply feedstock from crop and pasture land converted to growing energy crops. Using the demand for this later feedstock source, I estimate the potential land use change, which is shown in Figure 18.

Figure 18: Range of Potential Land Use Conversion Needed to Meet Biomass Demand



¹² According to EIA AEO 2007, 2006 US production of ethanol was 0.54 quads. A 25% requirement for biofuels would require over 7 quads of biofuels by 2025, using EIA projections of motor vehicle demand for gasoline and diesel.

The graph shows the land use change needed to meet the demand for biomass supplies under the initial strategy. The horizontal axis shows the “bins” of potential land use change I use to group the results. The first bin is all the scenarios with no land use change and the next shows the percentage of scenarios with some land use change but an amount less than 25 million acres. The remaining bins use increments of 25 million acres up to 75 million acres. Just over 40% of the scenarios required no land use conversion and slightly over 35% of the scenarios involved land use change up to 25 million acres. Therefore, nearly one quarter of the scenarios required significant land use conversion over 25 million acres. For reference, the USDA estimated that in 2002 total agricultural land supply was slightly over 440 million acres. Pasture and rangeland accounted for 587 million acres (Lubowski et al., 2006). USDA estimates of land rents suggest that most of this land use conversion would occur on crop and pasture lands. An important note is that readers should not interpret the results as an estimate of the probability distribution for this outcome. The results show the percentage of scenarios with each outcome, given the sampling method.

Under the scope of this analysis, I am limited to estimating the amount of land use conversion and not developing a detailed model of land and agricultural markets. Though, even this basic analysis shows that potentially significant amounts of land use conversion may be needed under this initial strategy for the 25% requirement, and land use changes on this scale would have considerable unintended consequences for land and food markets. Another important note is that the initial strategy considered in this chapter maintains EIA’s older assumption of a limit of about 12 billion gallons of corn-based ethanol. Chapter 4 will show other strategies that remove this constraint on corn ethanol and allow higher production when corn ethanol costs are competitive with other biofuels. Finally, the land use change results are sensitive to the assumed yield. I assumed a constant yield of 7 tons per acre based on recent research at RAND on producing biomass to mix with coal in coal-to-liquids plants (Bartis et al., forthcoming). These estimates are based on current methods to grow biomass and future progress could improve yields. However, lower yields are still possible. Producers may choose to convert low-yield pastureland because there are many regions where it is abundant and inexpensive to rent (National Agricultural Statistics Service and Agricultural Statistics Board, 2007).

In answering research question #1, Figures 12-15 show that the costs of implementing the 25% policy requirement with the initial strategy (measured in several ways) span a wide range, including many scenarios with very high-cost outcomes. Overall, the wide range in costs

reflects the considerable uncertainties in the input variables. While the costs span a wide range, Figure 16 shows the renewable energy requirement could also reduce GHG emissions significantly. The initial strategy decreased GHG emissions between 20% and 25% of total projected transportation sector emissions in most of the scenarios, but the results also showed many scenarios with even higher reductions.

In the analysis on surplus transfers, Figure 17 showed that fossil fuel producers could lose considerable amounts of surplus to consumers, and biomass producers could earn significant rents from the immense increase in biomass demand caused by the policy requirement. Finally, in many scenarios potentially large unintended consequences in land and food markets occur as producers convert crop and pasture land into growing biomass feedstock, because biomass prices rise enough to make biomass production more profitable on these lands. In the next section of this chapter, I quantify which uncertain factors are the most important in determining the outcomes of the policy requirement.

FINDINGS UNDER RESEARCH QUESTION #2

What are the currently uncertain key factors leading to high-cost and low-cost outcomes under a 25% renewable energy requirement?

In the final section of Chapter 2, I described the five steps I followed in applying RDM analytical methods to this policy requirement. In the second step, I stated that I categorize the results into low-cost and high-cost outcomes, and then use scenario discovery analysis to identify the key factors associated with each outcome.

I use two sets of information to define the low-cost and high-cost thresholds. I first use literature estimates for the social cost of carbon and oil dependency. Economists and policy analysts continue to debate the size of these externalities, and recent literature surveys found a wide range of estimates, particularly for the social cost of carbon (Tol, 2005; Parry, Walls, and Harrington, 2007). In this analysis, I use \$50 per tonne C (\$14 per tonne CO₂e) as a high-end estimate for the social cost of carbon. Tol (2005) found this value as the mean value of all the estimates from the peer-reviewed literature in a survey of 28 studies that produced a total of 94 estimates. While this value is the mean, it represents a high-end estimate because the results were highly right-skewed. I selected this value as part of the high-cost threshold because the literature suggests that if the renewable energy requirement's costs exceed this value

substantially then the policy's costs are likely exceed the benefits to society from reducing GHG emissions. The second component of the high-cost outcome is the social cost of oil dependency. The fuels model already calculates the social welfare benefit of reducing oil import expenditures (monopsony effect) and the second component I include in this calculation is the macroeconomic costs of oil dependency. For this value, I use the recent update in Leiby (2007) that estimates this externality at \$4.68 per barrel of oil. When summing these social costs, they translate in per unit costs of 0.8 cents per kwh and \$0.23 per gallon of gasoline equivalent.

For the low-cost outcome threshold, I use the estimate of the social cost of carbon NHTSA recently used in its proposal to increase CAFÉ standards (NHTSA, 2008). They also based their analysis on Tol (2005), and used a value of \$25 per tonne C or \$7 per tonne CO₂ equivalent. For the macroeconomic cost of oil dependency, I use the low-end value in Leiby (2007). He estimated this social cost at \$2.18 per barrel of oil. The sum of these social costs translates into per unit costs of 0.4 cents per kwh and \$0.11 per gallon of gasoline equivalent.

The social costs of carbon and oil dependency are not the only metrics a decision maker may use to judge the value of a renewable energy requirement. As noted in the first chapter, renewable energy offers additional benefits to society beyond carbon and oil consumption reductions. I have also analyzed the literature on consumer willingness-to-pay for renewable energy, which would presumably capture the carbon and oil reduction benefits as well as the additional benefits of renewable energy. However, the methods typically used to estimate these values, primarily contingent valuation surveys, often overestimate consumers' true willingness-to-pay and many analysts view them skeptically. In the Technical Appendix, I estimate thresholds for low-cost and high-cost outcomes using evidence from surveys and hedonic analysis on green electricity pricing programs, and calculate a similar set of values for these thresholds.

Finally, in selecting these criteria, I make an implicit judgment that decision makers use a satisficing criteria in judging the success of the policy. I label all of the scenarios with average costs of the policy requirement below the low-cost threshold as scenarios where society gains significant benefits in lower GHG emissions and oil consumption at low cost. In these scenarios, the 25% requirement may not maximize the net benefits from increasing renewable energy use. Microeconomic theory shows that a policy maximizes net benefits when marginal costs equal marginal benefits. The values for the social costs of carbon and oil consumption represent estimates of the marginal benefits and Figure 15 showed that the incremental costs of the policy requirement exceed the average costs in every scenario. Therefore, the low-cost scenarios are

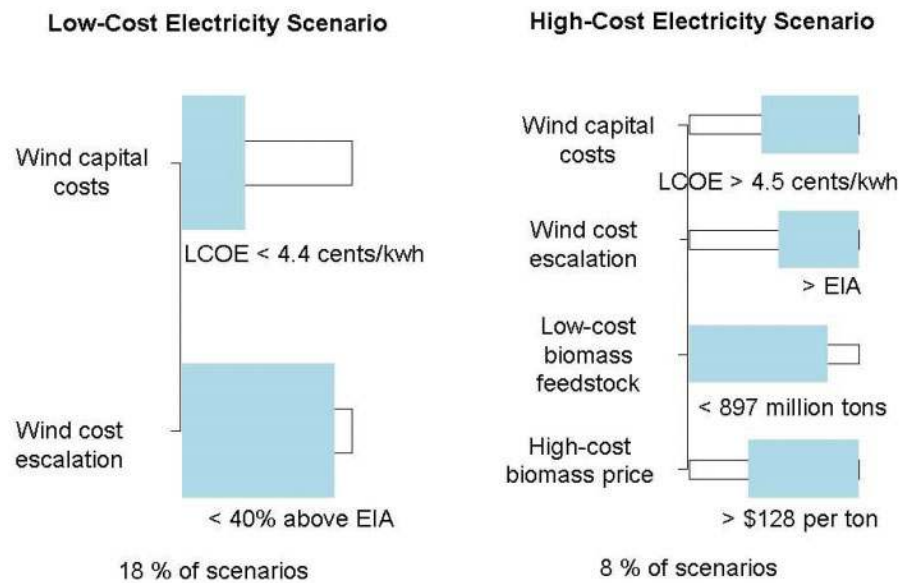
not maximizing net benefits unless the actual marginal benefits of reducing carbon emissions and oil consumption are higher than the values I selected. The literature does show higher estimates for the social costs of carbon, potentially much greater (Tol, 2005). In addition, high valuations on some of the benefits that I have not quantified would change this conclusion. I chose this satisficing criteria because the values of the marginal benefits are also deeply uncertain and the best assessment given the current state of knowledge is to identify a region where the benefits of the policy are prone to exceed the costs considerably. The same judgments apply to the range of high-cost outcomes.

After classifying the results into low-cost and high-cost outcomes, I combine this information with the input variables in a database. As noted in Chapter 2, I then use scenario discovery analysis, which uses a data mining technique to identify the key factors among the input variables that best explain the low-cost and high-cost outcomes. In the next section, I discuss the results in each market. This discussion includes a figure showing which factors the algorithm associated with each outcome and the range of values for each key factor. I then interpret this information into cost targets for renewable energy technologies correlated with the low-cost and high-cost outcomes. Finally, I use qualitative descriptions to summarize the information from the scenario discovery analysis.

Electricity Outcome Depends on Progress in Utilizing Marginal Wind Sites and Inexpensive Biomass Power

Figure 19 shows the set of variables identified by the scenario discovery analysis in the electricity market.

Figure 19: Key Factors Leading to Low-Cost and High-Cost Outcomes in the Electricity Market



The figure shows which variables the data mining algorithm associated with the low-cost and high-cost outcomes, and the percentage of total scenarios included within each outcome (18% of scenarios were low-cost outcomes and 8% were high-cost outcomes). The bold portion of the range for each variable also shows the values correlated with this outcome, and its proportion to the total assumed range. For instance, in the low-cost outcome the algorithm identified wind capital costs and escalation factors as the key factors leading to a low-cost outcome (the final section of the Technical Appendix contains a description of all the input variables used in the analysis and their ranges). Low-cost outcomes had wind power capital costs less than 25% below the EIA’s baseline assumption, which corresponded with approximately the lowest third of the assumed range of values. This portion of the range translates into levelized costs of electricity below 4.4 cents per kwh (the EIA’s baseline assumption is 5.8 cents per kwh). The second factor was that wind power cost escalation factors

did not exceed the EIA's baseline assumptions about how wind power costs increase with additions in capacity by more than 40%. These values translate into wind power costs below 10 cents per kwh after building nearly 90 GW of cumulative capacity. Current installed wind power capacity in the U.S. is approximately 17 GW and global combined capacity is over 90 GW (AWEA, 2008; GWEC, 2008). Reaching this level of capacity will require developing marginal wind power sites without significantly higher costs than EIA anticipates plus additional cost reductions in wind turbines. The cost of wind power far beyond current capacity levels is deeply uncertain. A recent DOE study on the costs of reaching 20% wind penetration suggests that costs within this range are feasible (EERE, 2008); however, low-cost wind power at this level of capacity depends on investments in the transmission grid that can connect wind-rich rural areas with the populated areas with electricity demand. These investments in the transmission grid require negotiating a patchwork of local, state, and federal jurisdictions, which is potentially a problem for new investments in wind power. Another challenge remains to balance power output with the intermittency of wind power at such high levels of penetration on regional transmission grids.

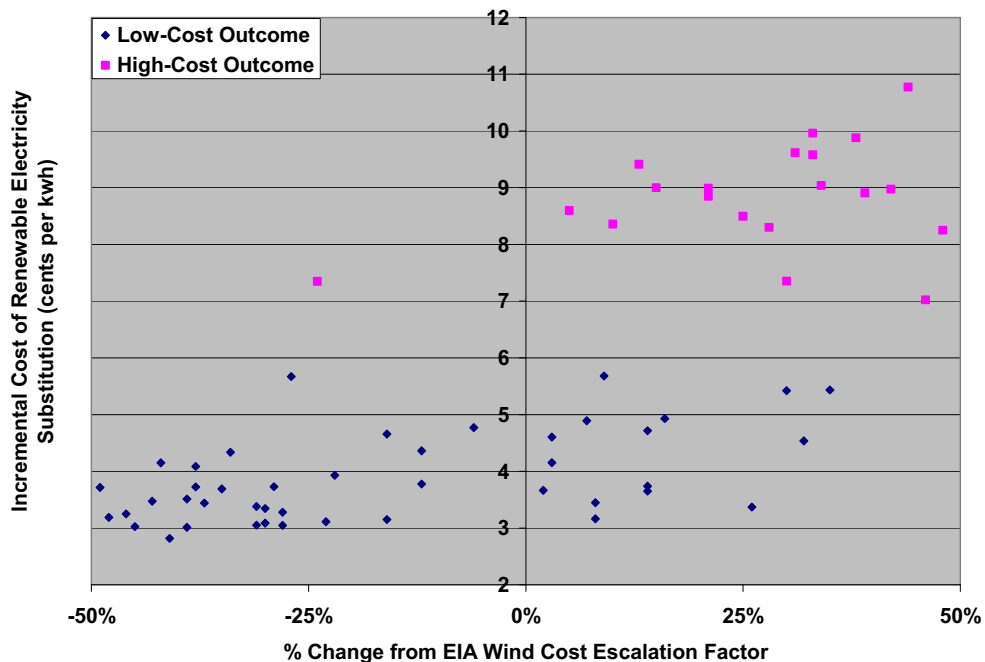
In the high-cost outcomes, the analysis found wind costs and biomass power costs as the key factors. If wind cost escalation exceeded the EIA's assumptions and biomass power was expensive, then even with some decline in wind capital costs the policy could result in a high-cost outcome. A key point with the scenario discovery results is that all these conditions need to occur simultaneously. The high-cost portions of the wind supply curve reflect sites with low-quality wind resources and sites with relatively high-quality resources but are located far from existing transmission lines. Wind power can exceed the EIA's assumptions about this portion of the supply curve in several ways: higher than expected costs to connect remote sites to the transmission grid, low capacity factors at sites with low wind speeds, and high costs to develop sites in remote areas. Potential contingencies that would raise costs of developing remote sites include permitting problems and high costs to bring construction equipment to remote areas. The analysis does not model these factors individually but captures them in the range of cost escalation factors used in the higher capacity portion of the wind supply curve.

The analysis on high-cost outcomes in the electricity market also found that biomass power was a key factor. Low-cost biomass supply below approximately 900 million tons was the third variable identified by the algorithm. The EIA's AEO 2007 has a maximum supply of low-cost biomass near 700-750 million tons in its high-yield scenario. Therefore, reaching supplies near 900 million tons will require improvements in feedstock cultivation and collection beyond

EIA’s current estimates. Other research has shown that supplies near 1 billion tons are feasible with high yields of waste material and energy crops (Perlack et al., 2005). The final factor was that the costs of high-cost biomass feedstock from crop and rangelands converted to biomass cultivation exceeded \$128 per ton. Current USDA estimates of land rents suggest that producing biomass on these lands at costs below \$125 per ton is possible (National Agricultural Statistics Service and Agricultural Statistics Board, 2007). However, the USDA’s estimates are for current land rents. If crop and pastureland values appreciate considerably or biomass feedstock production costs on these lands surpass expected costs, then exceeding the \$125 per ton benchmark is possible (the Technical Appendix contains a more detailed discussion of the land rent estimates).

The scenario discovery analysis identified the key factors associated with each outcome; however, interpreting these results in terms of renewable electricity production costs is difficult. For this reason, I also show the range of incremental costs of renewable electricity substitution estimated by the model for the low-cost and high-cost outcomes plotted against one of the key variables identified by the algorithm. This information is useful in identifying targets for achieving 25% renewable electricity at low cost and when the policy requirement may become costly. Figure 20 displays these results.

Figure 20: Low-Cost and High-Cost Outcome Incremental Costs of Renewable Electricity Substitution



The figure shows the percentage change from EIA's wind cost escalation factors on the horizontal axis and the incremental cost of renewable electricity substitution on the vertical axis. The incremental costs of renewable electricity substitution are the difference between the LCOE of a renewable electricity source and the costs of electricity produced from fossil fuels displaced by the renewable electricity. The reference fossil fuel technology varies by renewable electricity source and fossil fuel price. Chapter 2 and the Technical Appendix provide greater detail on this substitution calculation. EIA's wind cost escalation factors characterize the rising costs of wind power as installed capacity expands. In EIA's nominal assumptions, the cost curves have 5 steps corresponding with 0%, 20%, 50%, 100%, and 200% cost escalation over the initial cost, which also varies with the wind capital cost variable. In the analysis, I vary these cost escalation factors by 50% above and below EIA's values. For instance, cost escalation in the second step under a 50% decline would be 10% instead of 20%. The points depicted with diamonds correspond with the low-cost scenarios and the squares show high-cost outcomes.

The graph shows a clear separation in the incremental costs of renewable electricity substitution between the two outcomes. In the low-cost outcomes, renewable electricity substitutes for fossil fuels at incremental costs below 6 cents per kwh and the incremental costs of substitution exceed 7 cents per kwh in the high-cost outcomes. The results suggest a definite target for reaching 25% renewable electricity at low-cost. Renewable electricity sources need to supply approximately 500-700 billion kwh (range varies with price elasticity of demand) of new renewable electricity at incremental costs below 6 cents per kwh.

The graph also shows that the wind cost escalation factors are a good explanatory variable for the high-cost outcomes. In nearly all the high-cost outcomes, the cost escalation factors exceed EIA's baseline assumptions. In the low-cost outcomes, the wind cost escalation remained below EIA's assumptions, often by more than 25%, in most of the outcomes; however, the figure shows a group of scenarios with higher cost escalation. In these scenarios, wind power capital costs decline sufficiently to offset higher cost escalation.

Overall, the results show that the outcome in the electricity market is very sensitive to the costs of developing marginal wind sites. The low-cost scenarios depend on inexpensive wind power at high levels of new capacity and progress in wind turbine technology. The high-cost outcome shows that if wind costs exceed today's estimates of 2025 costs and inexpensive biomass is unavailable then high costs in the electricity market are possible. Figure 20 showed potential target for the incremental costs of renewable energy substitution. These costs in the low-cost outcomes remained below 6 cents per kwh with some scenarios as low as 3 cents per

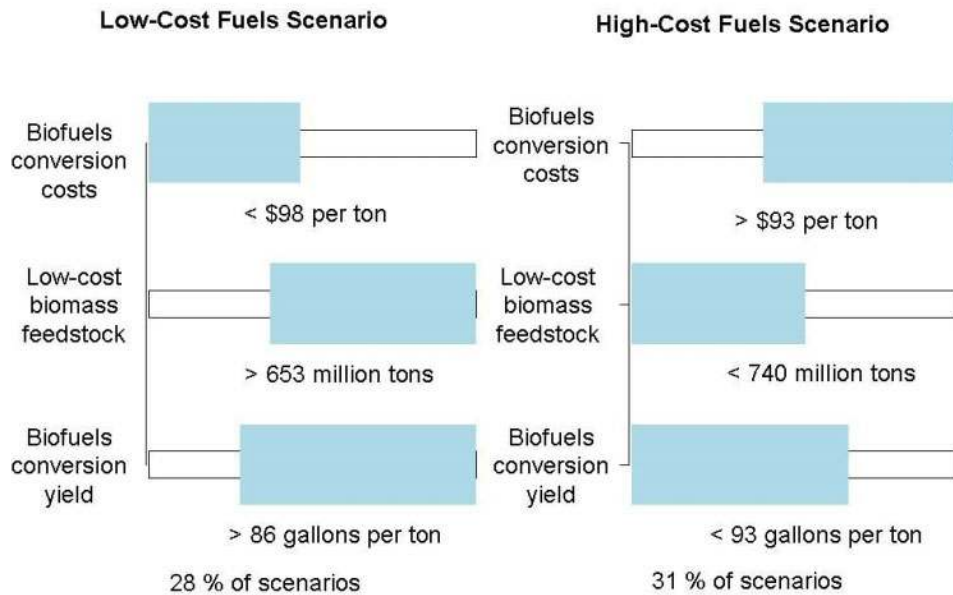
kwh. The figure showed the incremental costs of renewables substitution exceeded 7 cents per kwh in all of the high-cost outcomes and ranged up to almost 11 cents per kwh.

I now show the results of this analysis in the fuels market and follow the same order of presentation and explanation.

Low-Cost Fuels Outcome Requires Significant Progress in Biofuels Technologies and Feedstock Supply

Figure 21 displays the key variables identified by the scenario discovery analysis in the fuels market.

Figure 21: Key Factors Leading to Low-Cost and High-Cost Outcomes in the Electricity Market

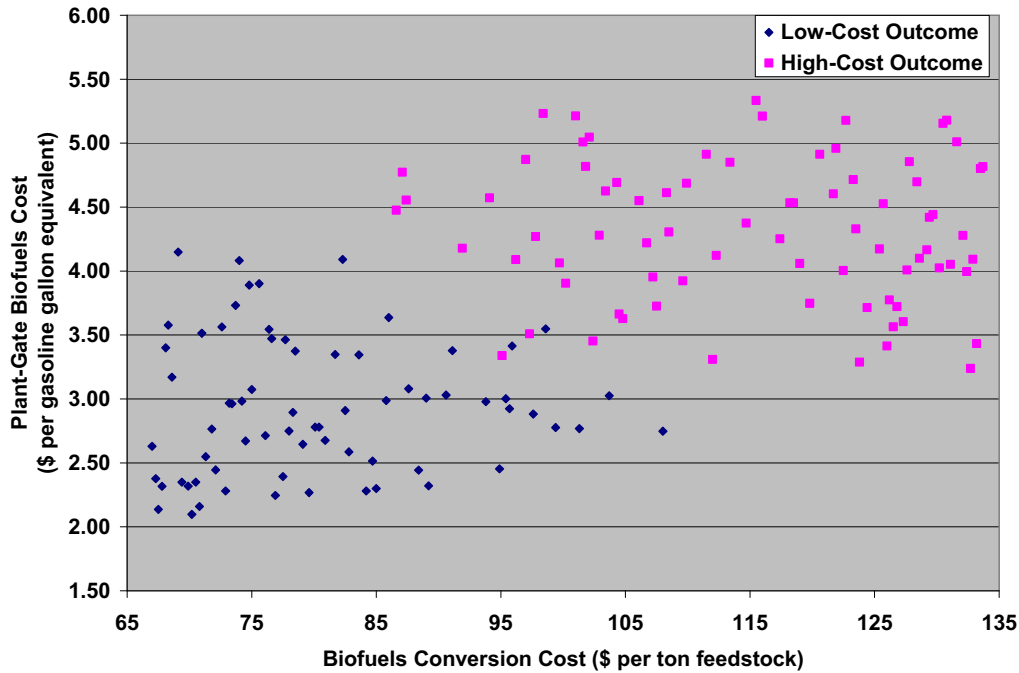


The figure illustrates that the scenario discovery analysis identified the same three variables for each outcome. It also shows 28% of the total scenarios were low-cost outcomes and 31% were high-cost outcomes. Progress in cellulosic ethanol and biomass-to-liquids technologies is the primary factor determining the outcome in the fuels market. Because the initial strategy constrains corn ethanol and biodiesel can only supply a limited amount of biofuels, cellulosic ethanol and biomass-to-liquids become the primary fuels produced to meet the 25% requirement. Both of these technologies are in a pre-commercial state today, and their

future costs at the 25% level are some of the greatest uncertainties in the analysis. The first factor shown in Figure 21 is the cost of converting biomass into liquid fuels using these technologies. The upper end of the range for this variable is \$134 per ton, which was derived using a recent estimate of 1st-of-a-kind plant costs for these technologies (Solomon et al., 2007), adding a 25% cost contingency, and including some cost reduction that occurs through learning (Ortiz, 2007). Even defining this high-end of the range is difficult because cost estimates for 1st-of-a-kind plants tend to underestimate costs when the technologies remain in a pre-commercial state and a higher cost contingency may be warranted. For the lower end of the range for biofuels conversion costs, I've used an estimate from a recent DOE-funded study on the costs of cellulosic ethanol for nth-of-kind plants after the technology reaches a commercial state (Aden et al., 2002). This estimate at the low end of the range is \$67 per ton of biomass feedstock. Figure 20 shows that low-cost outcomes were correlated with biofuels conversion costs below \$98 per ton, low-cost biomass supplies greater than 653 million tons, and biomass conversion yields above 86 gallons per ton of biomass feedstock. In the high-cost scenarios, biofuels conversion costs remained above \$93 per ton, low-cost biomass supplies less than 740 million tons, and conversion yields below 93 gallons per ton. These results show low-cost outcomes were associated with the lowest half of the assumed range and high-cost outcomes with the upper half. Reaching costs in the lower half of the range will require early commercialization of these technologies and rapid technological progress that reduces costs. The estimate at the upper limit of the range of conversion costs assumed some cost reductions from learning; therefore, reaching costs in the upper half of the range will require lower costs for 1st-of-a-kind plants with cost reductions as capacity expands.

Similar to the electricity market, I display the plant-gate costs for the marginal biofuel produced to meet the 25% requirement, sort the results by the low-cost and high-cost scenarios, and show one of the key factors identified by the analysis on the horizontal axis. I show this in Figure 22 to help further interpret the results.

Figure 22: Low-Cost and High-Cost Outcome Plant-Gate Biofuels Cost for Marginal Unit Meeting Requirement



The figure shows the biofuels conversion costs on the horizontal axis and the plant-gate cost of the marginal biofuel produced to meet the 25% requirement on the vertical axis. The points depicted with diamonds correspond with the low-cost scenarios and the squares show high-cost outcomes. The figure illustrates that the plant-gate costs of the marginal biofuel in most low-cost outcomes are below approximately \$3.25 per gallon of gasoline equivalent, and range from \$2.10-\$4.15 per gallon of gasoline equivalent. High-cost outcomes correspond with plant-gate costs above approximately \$3.75 per gallon of gasoline equivalent, and vary from \$3.24-\$5.33 per gallon of gasoline equivalent. The graph also shows the low-cost outcomes correspond with biofuels conversion costs below approximately \$100 per ton and high-cost outcomes occur above this point.

The graph also shows the range of plant-gate biofuels costs overlap in the two sets of outcomes. This occurs because these results show the plant-gate cost of the marginal biofuel; whereas the overall welfare loss determines whether a scenario is a low-cost or high-cost outcome. Higher marginal plant-gate costs can still result in low-cost outcomes when lower-cost biofuels comprise the majority of the supply curve and costs rise quickly when production nears the 25% level. The graph shows that most of the low-cost outcomes with high plant-gate costs also had relatively low conversion costs below \$85 per ton. Conversely, high-cost

outcomes can occur with lower marginal plant-gate costs when a large portion of the supply curve consists of relatively higher-cost biofuels and costs escalate less rapidly near the 25% level. This is also shown on the graph where most of the high-cost outcomes with plant-gate costs below \$4.00 per gallon had conversion costs above \$110 per ton.

In short, the plant-gate cost of the marginal biofuel is only an indicator, and the shape of the entire supply curve ultimately determines the outcome. Nonetheless, these results suggest a target for achieving 25% renewable fuels at low costs. Biofuels plant-gate costs need to remain below approximately \$3.25 per gallon gasoline equivalent after adding nearly 50 billion gallons gasoline equivalent of new production. If plant-gate costs exceed this threshold considerably, then the policy requirement is prone to high-cost outcomes.

Large Low-Cost Feedstock Supply Required to Avoid Land Use Changes

I also used the scenario discovery analysis on the land use change results shown in Figure 18, and identified the key factors common to the scenarios requiring land use change to meet demand for biomass feedstock. The scenario discovery analysis found that these outcomes were associated with a low-cost feedstock supply below 760million tons. The scenarios with lower supplies generally required land use conversion to meet the demand for biomass feedstock, and scenarios with larger supplies typically avoided this outcome. This level of feedstock supply is in the upper portion of the range of assumed values, far larger than current biomass use, and nearly equivalent to the maximum supply in the high-yield case of the biomass feedstock supply curves used in the AEO 2007 (Smith, 2008).

In summary, the scenario discovery analysis shows that achieving a low-cost outcome under the initial strategy for implementing the 25% renewable energy requirement requires significant progress in utilizing marginal wind sites, developing new biofuel technologies, and expanding biomass feedstock supplies. With more limited progress in these technologies, the policy requirement is susceptible to high-cost outcomes. Furthermore, without the advances in biomass feedstock supply, significant land use changes may be needed to supply demand for biomass feedstock. I now compare the costs of the policy requirement between markets and to other policies aimed at reducing GHG emissions.

FINDINGS UNDER RESEARCH QUESTION #3

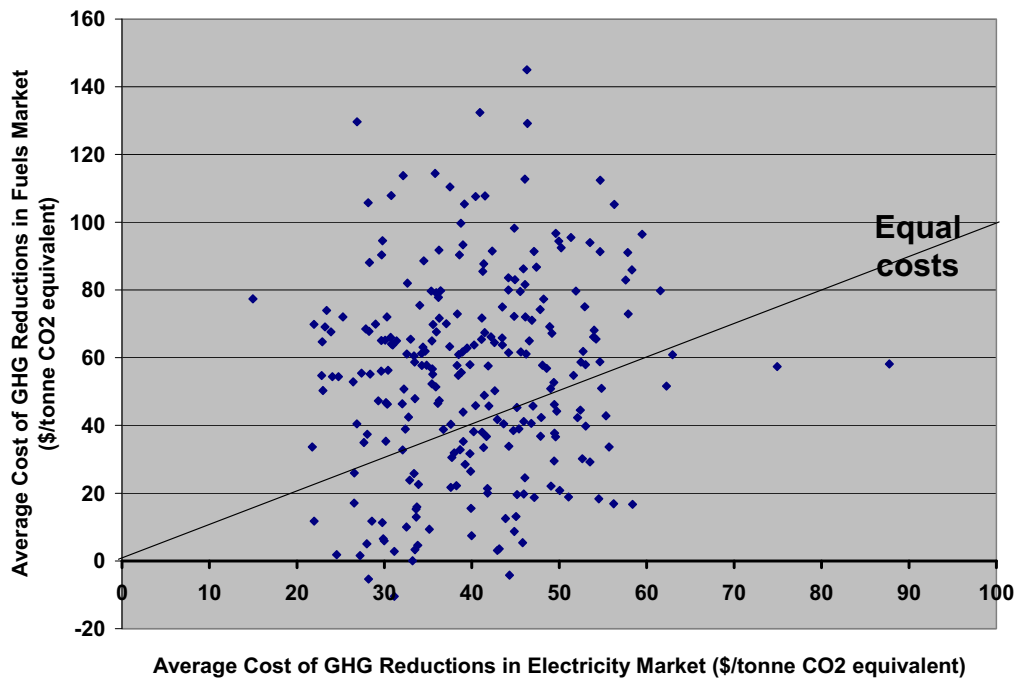
How does the cost-effectiveness of the renewable energy requirement compare with other policy options that reduce greenhouse gas emissions?

In Chapter 2, I noted that the models used for this analysis estimate the average and incremental costs of GHG reduction. I now use these metrics to judge the cost-effectiveness of the 25% renewable requirement and its cost-competitiveness with other policies with similar goals.

25% Requirement Costly to Reduce Greenhouse Gas Emissions, Especially for Biofuels

Figure 23 shows the average costs of GHG reduction for all 250 scenarios. The average cost of GHG reductions is the total welfare loss divided by the total GHG reductions and is in units of \$ per tonne of CO₂ equivalent.

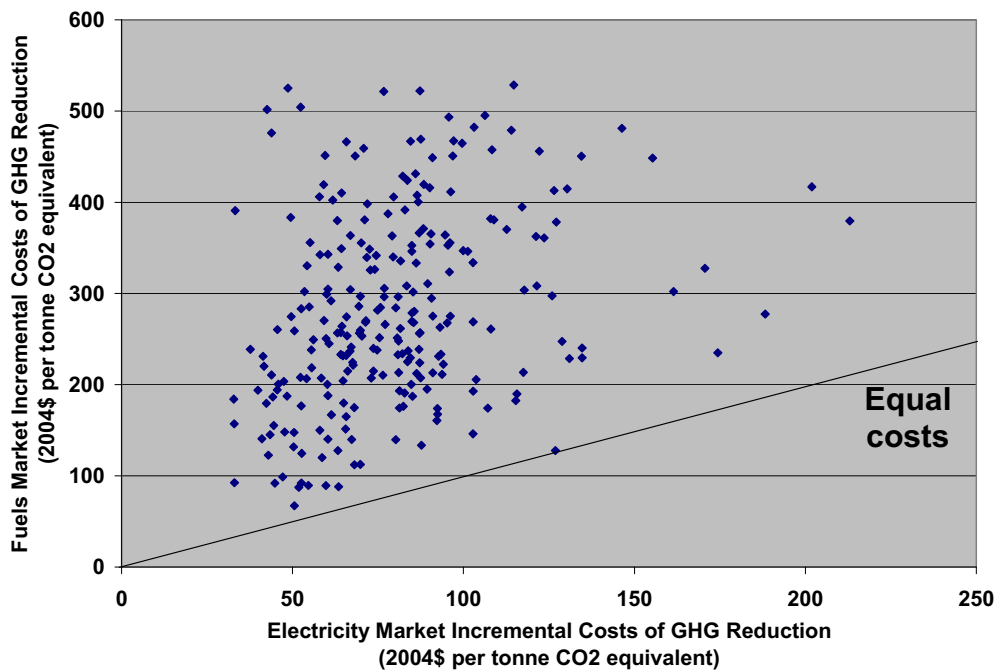
Figure 23: Average Cost of Greenhouse Gas Reductions



The horizontal axis displays this cost measure for the electricity market and the vertical axis show the result in the fuels market. The line in the graph displays the points with equal average costs of GHG reduction. Points above the line indicate scenarios with higher average costs of GHG reduction in the fuels market and 66% of the scenarios lie in this area. The costs in the electricity market range from \$15 - \$88 per tonne CO₂ equivalent, but include several results on both the low and high end that deviate from the majority of the scenarios. Nearly all of the scenarios in this market cost between \$20 and \$60 per tonne CO₂ equivalent. The average costs of GHG reduction span a much wider range in the fuels market. The results ranged from -\$11-\$125 per tonne CO₂ equivalent in this market.

The generally higher costs in the fuels market indicate an equal percentage requirement in both markets is not the most cost-effective policy for achieving GHG reductions. A lower requirement in the fuels market and higher level in the electricity market could achieve the same level of GHG reduction at lower cost (or higher reductions at the same cost). The average costs of GHG reduction measure the policy's overall cost relative to the emissions reductions but may conceal much greater incremental costs of GHG reduction. Figure 24 displays the estimates of incremental costs of GHG reductions.

Figure 24: Incremental Costs of Greenhouse Gas Reductions



The horizontal axis in the graph shows the incremental cost in the electricity market and the vertical axis shows the same metric calculated for the fuels market. The graph shows that, like the other cost measures, the incremental costs of GHG reduction vary considerably across the scenarios and the incremental cost of GHG reduction in the motor vehicle fuels market exceeds the fuels market in every scenario. The incremental costs of GHG reduction range from \$33-\$213 per tonne CO₂ equivalent in the electricity market, but similar to the average costs measure shown before several outlying scenarios influence this range. The large majority of scenarios in the electricity market cost between \$40 and \$125 per tonne CO₂ equivalent. The incremental costs of GHG reduction cover a much wider range and spread more evenly in the fuels market. The costs vary from \$67-\$529 per tonne CO₂ and exceed the incremental costs in the electricity market in every scenario. In fact, the incremental costs of GHG reduction in the fuels market are considerably higher (more than 2-3 times greater) than the electricity market in nearly every scenario.

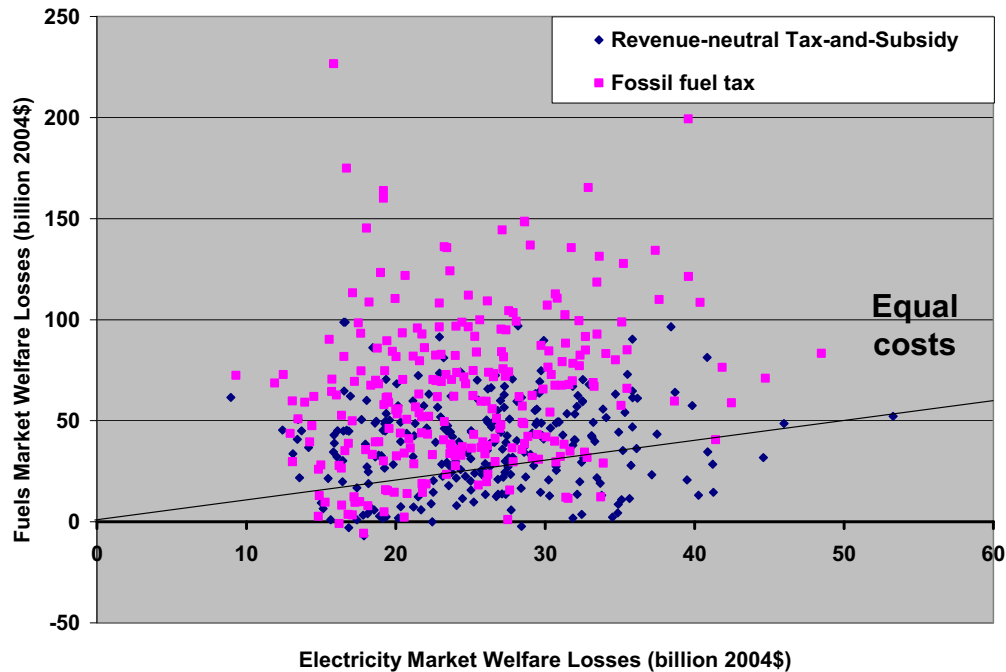
In addition to the relative cost differences between markets, the absolute costs in both markets exceed the estimated costs of GHG reductions with other policies. In a recent survey of proposals to limit U.S. GHG emissions, Aldy (2007) found the estimated CO₂ permit prices varied between \$20-\$30 per tonne CO₂ equivalent (2005\$) to achieve comparable decreases in emissions by 2025. This survey covered several analyses by EIA and MIT, which use different models and assumptions. These results are also subject to considerable uncertainty and assume no inefficiencies in implementing economy-wide cap-and-trade programs or carbon taxes. Actual policies could require trade-offs to pass the legislation resulting in higher costs than these idealized simulations.

I also noted in Chapter 2 that the policy requirement's benefits are broader than GHG reductions and attributing all of the incremental cost to one benefit neglects the others. While acknowledging this shortcoming, the very high incremental costs in many scenarios require large valuations on the policy's other benefits before it becomes cost-competitive with other policies. Finally, the incremental cost calculation is sensitive to the assumed baseline prices for fossil fuels and prices significantly higher than the EIA's assumptions would reduce these estimates. The EIA's AEO 2006 projected 2025 oil prices at \$48 per barrel, which is less than half today's oil prices that remain near \$100 per barrel. Substantially higher oil prices would lower the incremental costs.

Policy Choice Can Exacerbate Welfare Losses if Renewables Are Expensive

The earlier results shown in this chapter used a revenue-neutral tax-and-subsidy pricing mechanism to implement the 25% policy requirement. Chapter 2 described two other alternatives to this mechanism: a fossil fuel tax and renewables subsidy. I also described how these pricing mechanisms could affect the welfare loss calculations. The next set of results shows the change in welfare losses using the fossil fuel tax.

Figure 25: Welfare Losses Using Fossil Fuel Tax Pricing Mechanism



Welfare losses in the electricity market are shown on the horizontal axis and the vertical axis display welfare losses for the fuels market. The range of losses are similar in the electricity market and range from \$9 billion to \$48 billion (2004\$). The welfare losses increase substantially in the fuels market and now vary from -\$6 billion to \$227billion. The percentage of scenarios with higher welfare losses in the fuels market also increases from 68% under the revenue-neutral tax-and-subsidy mechanism to 87% with the fossil fuel tax. The large increase in the welfare losses occurs from deadweight losses in the fuels market. In some scenarios, the tax on fossil fuels exceeds \$4 per gallon and with this substantial increase in the price of fuel consumers significantly reduce consumption. With the large drops in consumption, consumers incur significant deadweight losses.

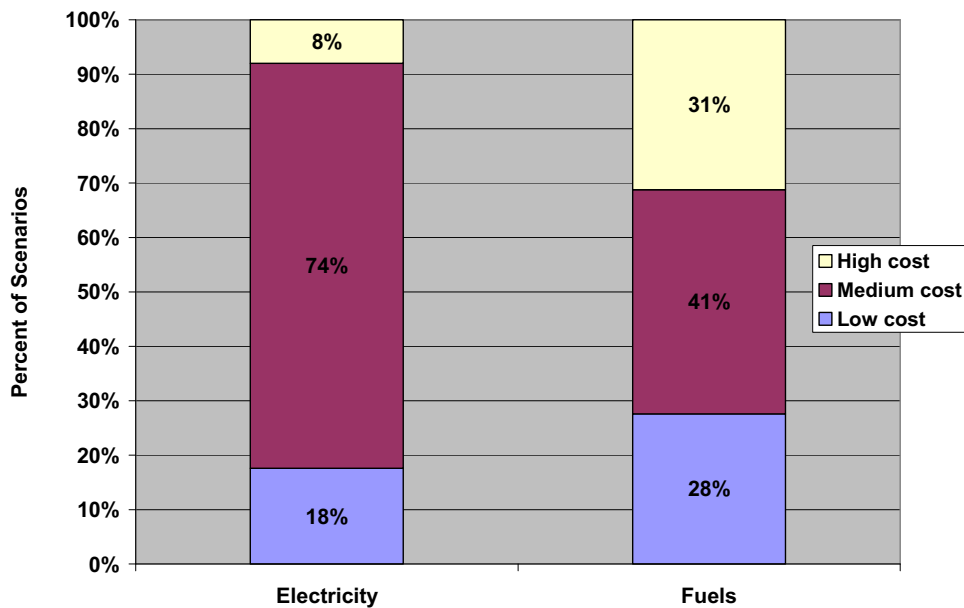
Consumers incur large deadweight losses when the cost differences between renewables and fossil fuels are large but it does have the benefit of promoting more efficient use of the

energy supply. At the margin, the marginal cost of energy equals the willingness-to-pay of consumers. Under the other pricing mechanisms, the marginal costs of renewables exceed consumer's willingness-to-pay for energy implied in the demand curve. This mechanism also limits the total incremental resource costs of the 25% policy requirement as consumers decrease their demand. Overall, while the fossil fuel tax promotes more efficient use of the energy supply, the potentially large price increases can result in extremely large welfare losses. I have not shown results using the subsidy pricing mechanism. Toman et al. (2008) found that the subsidy pricing case further exacerbated the policy's costs when renewable energy is expensive because market prices do not reflect rising costs of renewable energy and encourage consumers to lower demand.

Initial Strategy Vulnerable if Technological Progress Limited

The analysis in this chapter shows that the initial strategy incurs a wide range of potential costs with potentially very high costs in some scenarios. Reaching 25% renewable energy in both markets reduces GHG emissions and oil consumption significantly. The scenario discovery analysis found that achieving 25% renewable energy at low cost in both markets requires significant progress in utilizing wind power at marginal sites, developing new biofuels technologies, and expanding biomass feedstock supplies to the capacity needed for a 25% requirement. The analysis on the high-cost scenarios shows that the policy's costs exceed most estimates of the social costs of carbon and oil dependency when progress in wind power and biofuels technologies is more limited. In fact, even with some progress in biofuels technologies, high-cost outcomes are possible. Figure 26 summarizes how the initial strategy performs on the low-cost and high-cost outcomes of interest.

Figure 26: Percentage of Low-Cost and High-Cost Outcomes Under Initial Strategy



The first column shows the percentage of scenarios in the low-, medium-, and high-cost outcomes in the electricity market, and the second column displays the percentages for the fuels market. The lowest portion of each column represents the percentage of low-cost outcomes. In the electricity market, 18% of the scenarios resulted in low-cost outcomes while 28% of the scenarios in the fuels market met the low-cost threshold. The middle portion of each column displays the percentage of medium-cost outcomes, which were 74% and 41% for the electricity and fuels markets, respectively. The top portion of each column shows the percentage of high-cost scenarios. The electricity market had 8% high-cost outcomes while 31% of the scenarios exceeded this threshold in the fuels market.

The graph shows a larger percentage of low-cost outcomes in the fuels market but this market also had a much greater percentage of high-cost outcomes. In the electricity market, the majority of scenarios resulted in low- or medium-cost outcomes. The opposite occurred in the fuels market where medium- or high-cost outcomes comprised over 70% of the results. This summary of the results shows greater risks of costly outcomes in the fuels market under the initial strategy.

Overall, the results and analysis show that the initial strategy is vulnerable to costly outcomes because only a limited number of technologies can expand significantly to reach the 25% level. The outcome then depends on the costs of vastly increasing the capacity these few

key technologies. In the fuels market, an additional vulnerability is that cellulosic ethanol and biomass-to-liquids technologies needed to reach the 25% level are not in a commercial state today, and the costs of achieving the 25% level are highly uncertain at present. In this analysis, I have not quantified probabilities of these scenarios; however, the set of conditions leading to the high-cost outcomes is not unrealistic and warrants analysis of new strategies that can hedge against this outcome.

Based on these results, I devised a new set of strategies that expands the set of technologies used in the policy requirement with a focus on using technologies that are currently in a commercial state. For these reasons, I introduce strategies that allow additional corn ethanol production and energy efficiency to qualify as resources to meet the policy requirement. In additional strategies, I explicitly limit the costs of the policy using a “safety valve” that allows utilities and refiners to pay a constant fee when renewable energy costs reach a predetermined threshold.

CHAPTER 4: FINDING MORE ROBUST STRATEGIES

In this chapter, I analyze five additional strategies that address the vulnerabilities of the initial strategy noted in the previous chapter. For each of these strategies, I present measures of the strategy's costs, benefits, potential trade-offs with other objectives, and relative percentages of low-cost and high-cost outcomes. As I present these results, I describe three broad scenarios of future renewable energy costs that emerge as the key uncertainty affecting the outcome. I conclude the chapter by summarizing how each strategy performs across these broad scenarios, and which strategy is most robust. The analysis on these strategies answers the two final research questions.

What options in designing the requirement can improve cost-effectiveness?

How can policymakers mitigate risks of high-cost outcomes under the requirement?

The five additional strategies for implementing the renewable energy requirement vary along three dimensions: increasing corn ethanol production, including use of energy efficiency, and using a safety valve to contain costs. The initial strategy limited corn ethanol production, which was based on EIA's assumptions in the AEO 2006. EIA recently revised this assumption and allowed unconstrained corn ethanol in their analysis of a 25 x 25 requirement. In its analysis of this policy, the EIA estimated total corn ethanol production would rise to 25 billion gallons and this result suggests the 12 billion gallon constraint may exclude cost-effective opportunities to use corn ethanol to meet the 25% requirement. In the first strategy considered in this chapter, I allow unconstrained corn ethanol production but vary the corn ethanol supply curve to account for future improvements in this technology and variable corn prices. When corn ethanol is competitive, additional corn ethanol production can reduce welfare losses from the policy, but this option comes with a trade-off in more limited greenhouse gas emission reductions from this biofuel (higher carbon intensity relative to cellulosic ethanol and biomass-to-liquids), possibly considerable increases in the price of corn (with associated deadweight losses in corn consumption and surplus transfers), and increasing natural gas demand (corn ethanol production is natural gas intensive).

The next policy option allows energy efficiency in the electricity and motor fuels sectors to count towards meeting the renewable energy requirement. Several states already allow energy efficiency in their renewable portfolio standards, and this strategy would expand this option to the fuels market also. Some studies suggest energy efficiency can provide low-cost opportunities to reduce GHG emissions and oil consumption in the near term (Creys et al. 2007). Therefore, energy efficiency could displace high-cost renewable energy sources in many of the costly outcomes. This option could help reduce the overall costs of the policy and may mitigate some of the extreme outcomes. However, the costs and savings potential of energy efficiency are also uncertain and I allow both these factors to vary in the analysis.

The third option adds a “safety valve” that allows refiners and utilities to buy renewable energy credits from the government at a set price when the credit price reaches a specified threshold. EIA used this option in its analyses of RPS proposals (EIA, 2003; EIA, 2007e). This option reduces the risk of extreme-cost outcomes as the safety valve explicitly limits the costs of the policy. I estimate a safety valve price that attempts to limit the policy’s average cost from exceeding high-cost outcome threshold. As the results will show, average costs of the policy still vary; but the safety valve nearly eliminates high-cost outcomes.

Table 3 shows how I apply the strategy components in each of the six total strategies:

Table 3: Summary of Strategy Components

Strategy	Strategy Components		
	Unconstrained corn ethanol	Efficiency Substitutes for Renewables	Safety Valve
Initial			
Ethanol unconstrained	X		
Efficiency		X	
Joint	X	X	
Safety valve only			X
All combined	X	X	X

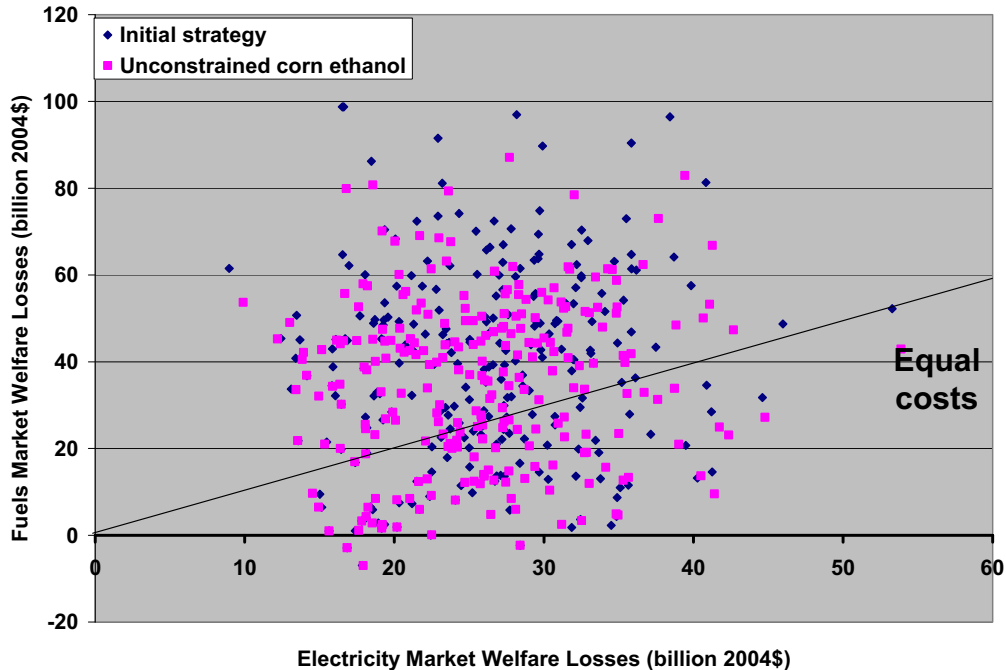
The initial strategy, shown in Chapter 3, uses a renewable energy requirement with constrained corn ethanol production, no option for energy efficiency, or safety valve. The second strategy

allows unconstrained corn ethanol production and treats these costs as another uncertainty. The third strategy keeps the constraint on corn ethanol but allows energy efficiency to count towards meeting the 25% requirement. I introduce the corn ethanol and efficiency policy options separately to directly compare them with the initial strategy. The fourth strategy includes both unconstrained corn ethanol and energy efficiency to examine any interaction effects. The fifth strategy implements a safety valve without additional corn ethanol or energy efficiency and the final strategy combines all of the strategy components. I apply the same experimental design over the uncertain parameters to each of these strategies. The remainder of the chapter presents the results on each strategy focusing on the relative change in welfare losses, any trade-offs in using these policy options, and percentage of low-cost and high-cost outcomes.

Increasing Corn Ethanol can Reduce Fuels Market Welfare Losses Marginally

In the analysis shown in the remainder of this chapter, I evaluated the models using the same 250 combinations of input values that I used for the initial strategy shown in Chapter 3. I present scatter plots comparing these strategies to the initial strategy to illustrate their impact on welfare losses and GHG emissions as well as any trade-offs that the new strategy may have relative to the initial strategy. I also show how each of the strategies affect the percentage of low-cost and high-cost outcomes. Figures 27-32 display graphs summarizing the results for the second strategy allowing unconstrained corn ethanol production.

Figure 27: Welfare Losses in Each Market with Unconstrained Ethanol Strategy

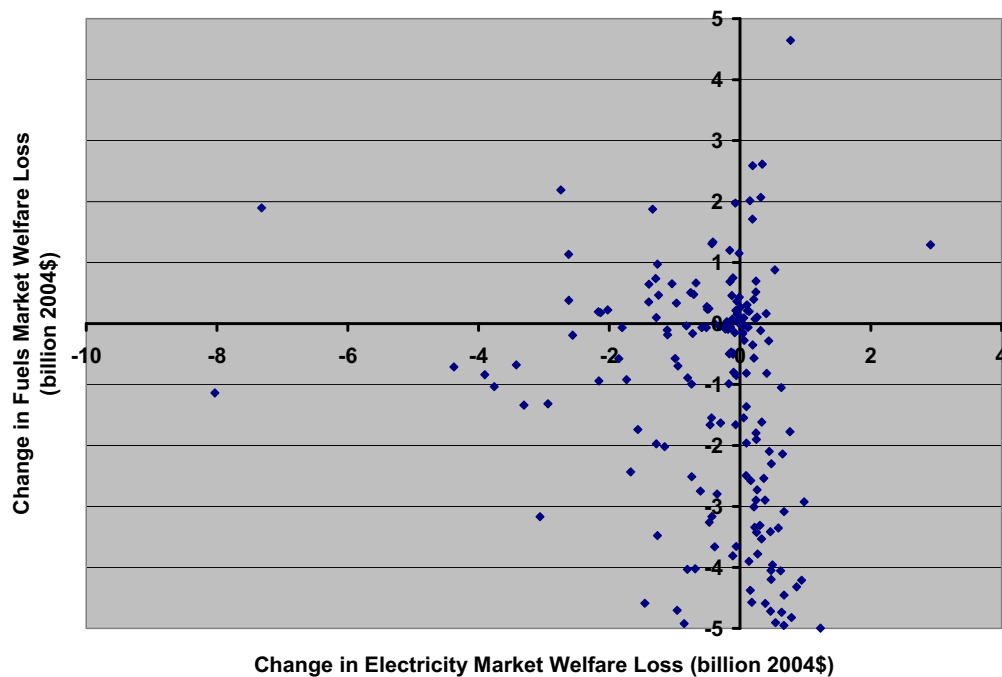


The figure shows the range of welfare losses in each market for the unconstrained ethanol strategy and the initial strategy. The points illustrated with the diamond represent the outcomes for the initial strategy. The squares represent results for the unconstrained ethanol strategy. The graph shows that most of the points overlap in the lower-cost portion of the graph but they start to deviate for scenarios with higher welfare costs under the initial strategy. This occurs because corn ethanol is more cost-effective at higher costs and displaces higher-cost biofuels from the initial strategy. This substitution reduces welfare costs in the fuels market, which is seen by a downward shift in many of the points. The reduction in welfare costs for biofuels is offset by higher deadweight losses in the corn market though. Higher corn prices reduce corn consumption and this deadweight loss is potentially sizeable when corn price increases are large. Welfare losses in the fuels market still remain higher than the electricity market in most scenarios. With the unconstrained ethanol strategy, the percentage of scenarios with higher welfare losses in the fuels market drops from 68% to 66%.

The effects on the electricity market are more complicated and involve offsetting effects. Higher corn ethanol production can increase the supply of cost-competitive biomass feedstock in the electricity market, which reduces welfare costs if the biomass power displaces higher-cost renewable electricity. A second effect from increasing corn ethanol production is higher natural gas demand relative to the initial strategy because producing corn ethanol is natural gas intensive. The net change in natural gas demand is still a decline in most scenarios; the decline is just lower than under the initial strategy. The higher relative natural gas demand raises welfare costs in the electricity market because this was an important effect of substituting renewable electricity in this market.

Figure 28 shows the change in welfare losses for each scenario between the initial and unconstrained corn ethanol strategies.

Figure 28: Change in Welfare Losses with Unconstrained Ethanol Strategy



The graph shows changes in welfare losses between the unconstrained ethanol scenario and initial strategy (difference between initial strategy and unconstrained ethanol strategy welfare loss). Negative results indicate decreases in welfare losses in the unconstrained ethanol strategy while positive results show increases. The horizontal axis displays the change in the electricity market while the vertical axis shows the change in the fuels market. The figure shows that allowing additional corn ethanol production can reduce welfare losses in the fuels market

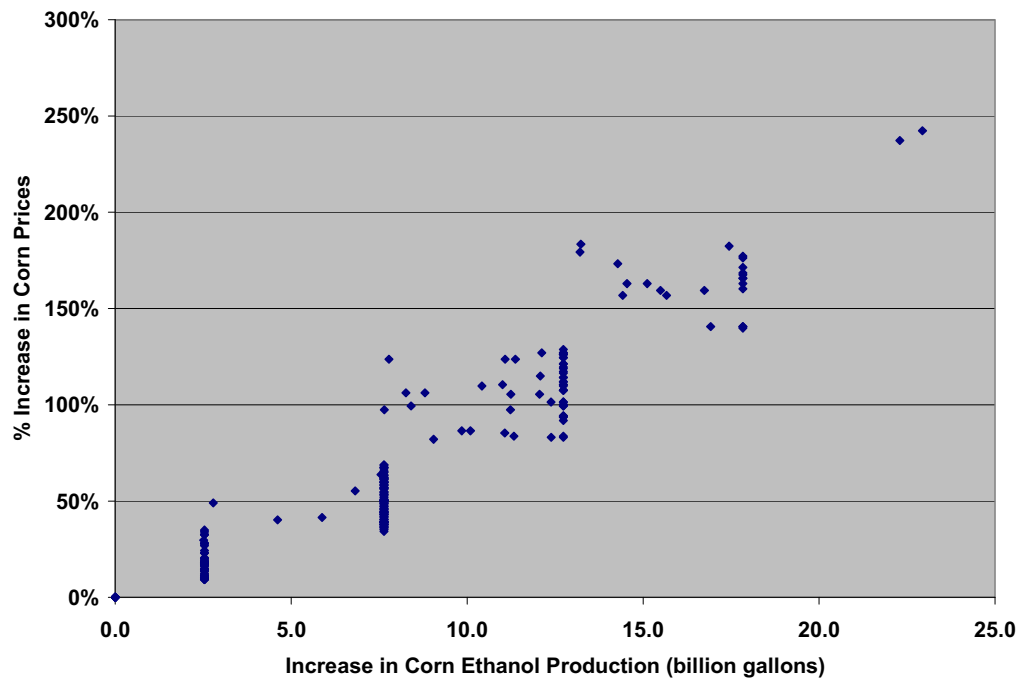
marginally in some scenarios. A large number of scenarios had no effect on welfare losses, which are shown with the cluster of points near the origin. Most of the decreases in welfare losses are less than \$5 billion but a few scenarios had larger effects.

The graph shows greater corn ethanol production can reduce welfare losses in the fuels market, but expanding corn ethanol production involves trade-offs with higher corn prices and potentially higher welfare losses in the electricity market. As noted earlier, higher corn prices incur deadweight losses for corn consumers and in several scenarios these losses exceed the savings in resource costs, as shown in the results with negative costs in the fuels market.

The graph shows the offsetting effects in the electricity market. Generally, increases in welfare losses in the electricity are correlated with declines in welfare losses in the fuels market. The graph does show many scenarios with lower welfare losses in the electricity market, which indicate the situations where biomass power became more cost-competitive and displaced higher-cost renewable electricity.

As noted above, an important result of higher corn ethanol production is the potential corn price increases caused by higher corn ethanol production. Figure 29 shows the increase in corn ethanol production and the related increases in corn prices.

Figure 29: Corn Ethanol Production and Increases in Corn Prices

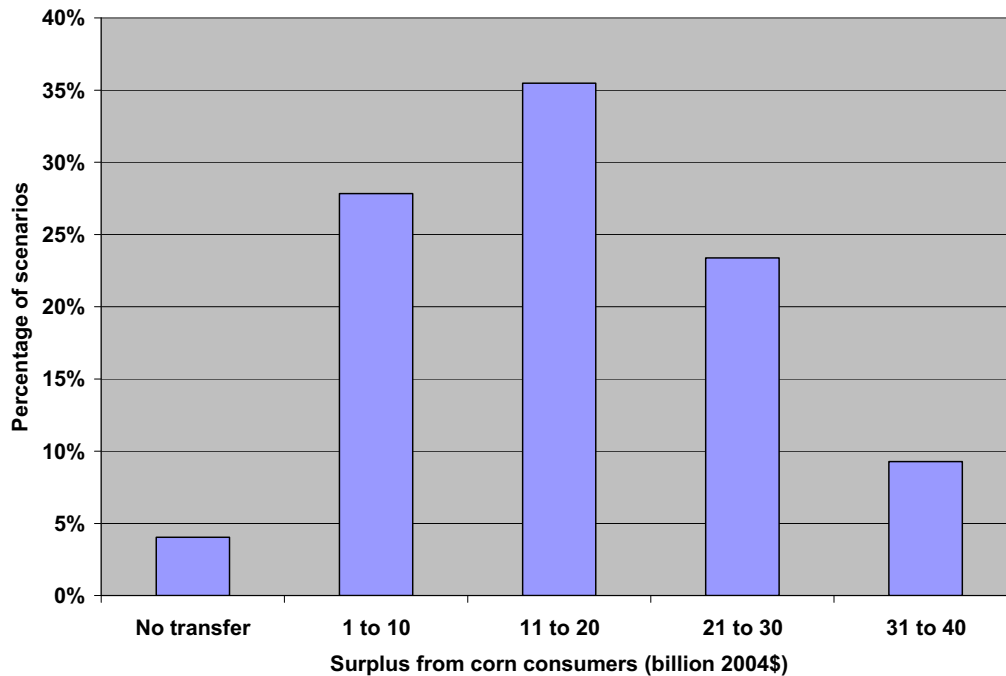


The horizontal axis in this graph shows the increase in corn ethanol production in each scenario (in addition to a baseline level of 12 billion gallons). The model assumes a range of initial corn prices in 2025 from \$2.50 per bushel to \$4.00 per bushel. EIA uses a long-run corn price projection of \$3 per bushel in 2025 based on USDA estimates (EIA, 2008a). The vertical axis shows the percentage increase in corn prices for each increase in corn ethanol production.

The graph shows that new corn ethanol production increases to a maximum of 23 billion gallons of corn ethanol production in addition to the 12 billion assumed in the baseline. The maximum of the results is a very large increase and not representative of the range. The majority of scenarios added between 8-13 billion gallons of new corn ethanol. The vertical clusters of results in the graph show cases where corn ethanol was an inframarginal resource (and numerous scenarios have the same amount of production). The points cluster in these areas because I use a step function to represent the corn ethanol supply curve, which results in numerous scenarios using the same amount of corn ethanol when it is an inframarginal resource. In the scenarios between these clusters, corn ethanol production was the marginal resource and the equilibrium occurred along a segment of the supply curve. The range of price increases is very large. The graph shows that corn prices in most scenarios increase between 50%-200% (EIA's 25x25 analysis found about a 100% increase), but in two scenarios corn prices increased by nearly 250%.

The higher prices for corn also result in surplus transfers from corn consumers to corn producers. Figure 30 shows the range of transfers in the results.

Figure 30: Range of Corn Consumer Surplus Transfers with Unconstrained Ethanol Strategy



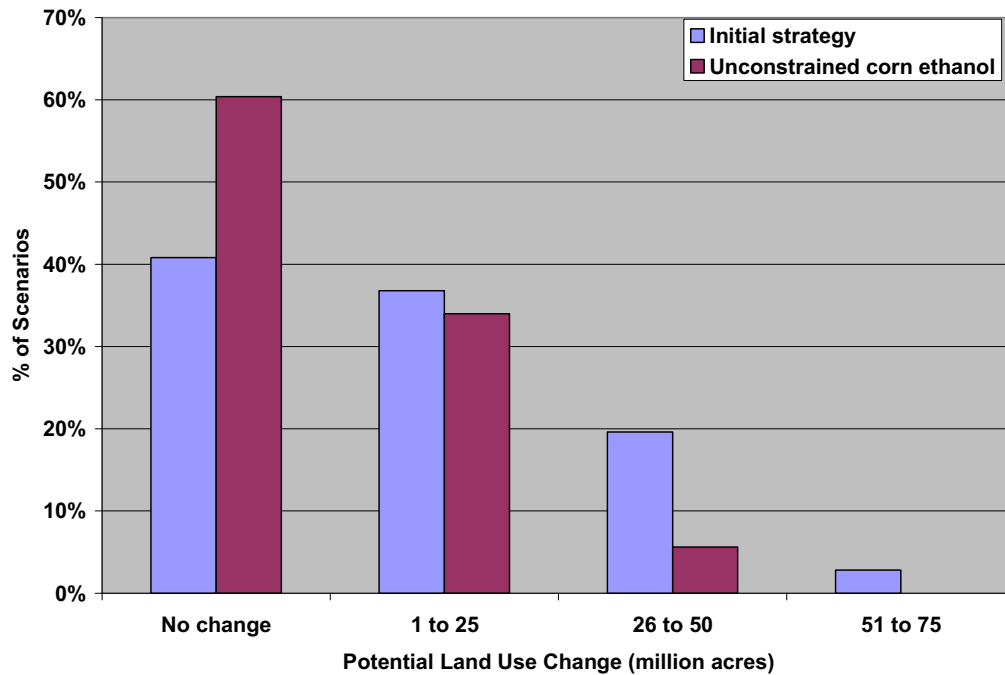
The graph has five bins along the horizontal axis representing different levels of surplus transfers. The vertical axis shows the percentage of scenarios within each bin. Slightly less than 5% of the scenarios had no surplus transfer, which implies approximately 95% of the scenarios involved some increase in corn ethanol production from the assumed baseline level. Almost two-thirds of the scenarios involved some consumer surplus transfer to corn producers below \$20 billion dollars. Finally, in over 30% of the scenarios corn consumer surplus transfers exceeded \$20 billion.

Of note, these higher corn prices manifest in multiple ways because corn is consumed directly and it is also an input to a wide array of food products and raising livestock. Because of this widespread consumption of corn, any price increases induced by an increasing renewable energy requirement are likely to provoke significant opposition by industries that consume corn. The recent vocal opposition of the Grocery Manufacturers Association to the Renewable Fuels Standard, discussed in Chapter 2, is further evidence that a substantial increase in the renewable energy requirement in the motor vehicle fuels market is likely to face widespread resistance if the price changes are large. The results later in this chapter will show how

including energy efficiency in the implementation strategy can mitigate some of the corn price increase and possible dissatisfaction among corn consumers.

Chapter 3 showed that one of the unintended consequences of the policy requirement was potentially significant conversion of crop and pasture land into growing biomass. Corn ethanol production can reduce some of the land use conversion for biomass, and Figure 31 shows the range of land use changes in both strategies.

Figure 31: Effects of Unconstrained Ethanol Strategy on Potential Land Use Change

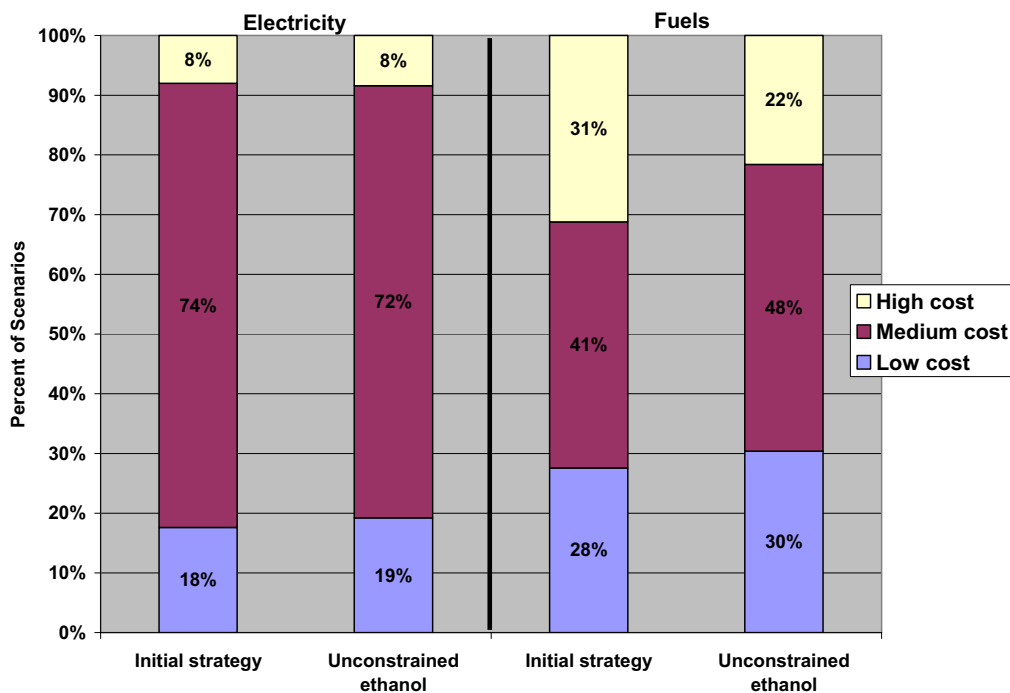


This figure displays the same information shown on Figure 18 in Chapter 3, but now adds the land use change estimates for the unconstrained ethanol strategy. The first column within each bin shows the result from the initial strategy and the second column presents the estimate for the unconstrained ethanol strategy. The figure shows that land use change declines with the unconstrained ethanol strategy. The percentage of scenarios with no land use change increases to 60% while the percentages decline in all the bins with some amount of land use change. This downward shift in the amount of land use change shows corn ethanol is cost-effective in many scenarios and displaces some of the costly biofuels produced with high-cost biomass feedstock.

Of note, these results only reflect the change in land use for biomass feedstock production and do not capture land use changes from increasing corn production. It was beyond the scope of this analysis to estimate potential land use changes for corn production, but EIA’s analysis on the 25 x 25 policy suggests that higher corn ethanol production requires limited land use change. In its analysis, the EIA found producing 25 billion gallons of corn ethanol increased land planted with corn by only 2 million acres. This is a limited change in acreage for such a large increase in corn ethanol production; however, EIA does project that the U.S. switches from a net exporter of corn to a net importer of corn, which suggests that the land use changes from higher corn production occur in a foreign country.

The next graph shows the final comparison for this strategy, which evaluates how the unconstrained corn ethanol strategy affects the percentage of low-cost and high-cost outcomes.

Figure 32: Effects of Unconstrained Ethanol Strategy on Percentage of Low-Cost and High-Cost Outcomes



In Figure 32, the first two columns compare the percentage of low- and high-cost outcomes in the electricity market for the initial and unconstrained ethanol strategies. The third and fourth columns compare the results for the fuels market. The graph shows increasing corn ethanol production marginally decreases welfare losses in the fuels market with limited overall effects on

the electricity market. In the fuels market, the percentage of high-cost outcomes decreases by 9% while the percentages of low-cost and medium-cost outcomes increase by 2% and 7%, respectively. In the electricity market, the percentage of low-cost outcomes increases slightly by 1%. The results show that this strategy can mitigate some of the high-cost outcomes in the fuels market but does not reduce the risk significantly. In addition, the marginal change in high-cost outcomes comes with a trade-off of potentially large surplus transfers in the corn market. The next section shows that including efficiency has potentially greater effects.

Efficiency Can Reduce Welfare Losses but Trades-off with other Objectives

Before evaluating the results for the efficiency strategy, I describe some of the options for implementing this strategy and the methods I've used to develop the energy efficiency cost curves. As noted earlier, many states currently allow energy efficiency to meet their renewable portfolio standards. Most of these policies allow a specified set of technologies to count towards meeting the utility's renewable electricity requirement, but administrative agencies have not passed specific rules for the role of energy efficiency resources in their RPS policies (DSIRE, 2008b). In this analysis, I assume each technology has a standard level of demand reduction that the utility earns when a customer uses the technology. In a recent analysis for the National Commission on Energy Policy, Rosenquist et al. (2004) estimated the annual energy savings from a set of residential and commercial building and appliance improvements. Through similar analysis, the policy requirement could set standard electricity savings for qualifying technologies. Then, utilities can choose to implement energy efficiency measures or increase renewable energy use. For instance, a utility may offer a financial incentive to a local homebuilder to install high-efficiency insulation in a development of new homes instead of building or purchasing credits for more costly renewable energy. The utility would prefer to invest in this efficiency measure if it costs less than developing new renewable energy.

In the fuels market, the efficiency changes could occur at the auto consumer or producer level. Refiners could earn credits toward the requirement by offering incentives to consumers to purchase high-efficiency vehicles. For instance, they could offer rebates for hybrid and advanced diesel vehicles to encourage more consumers to purchase these vehicles. Another option is for refiners to enter into agreements with auto producers to exceed the fleetwide fuel economy standards mandated by the CAFÉ program. The NHTSA currently estimates fuel consumption savings for the CAFÉ program and the same methods could calculate annual fuel savings for this program.

A key concern with both of these programs is that utilities and refiners may earn credits for efficiency improvements that would have occurred without the requirement. For example, refiners may earn credit for a rebate program on hybrid vehicles but some of the consumers using the rebates planned to purchase the hybrid vehicle even without an incentive. In this example, the program becomes a transfer payment to the hybrid vehicle consumer with no real reduction in energy consumption. The literature shows that utility demand side management programs experienced some of these problems and that putting utilities and refiners in charge of the programs potentially increases the likelihood of occurrence. A second concern is the accuracy of the energy savings used to offset renewable energy requirements. Ideally, these programs would use ex-post assessments to verify the energy savings and possibly revise standards.

I developed cost curves for energy efficiency following a similar process that I used for renewable energy technologies. I used recent literature estimates for the costs of saved energy (CSE) for electricity- and fuel-saving technologies combined with analysis on the aggregate potential for saving energy. The CSE calculation is similar to estimate for LCOE in electric-power technologies. Both involve an initial capital expenditure that yields a stream of energy savings or electricity production over the lifetime of the product or power plant. The calculation annualizes the initial capital expenses and divides by annual energy savings, and the result is the cost per unit of energy. Thus, the CSE is comparable to LCOE for electricity technologies and per unit costs of biofuels. For estimates of the aggregate savings potential, I relied on analyses that estimate aggregate savings based on the turnover rates for automobiles and electricity-saving technologies. Since new automobile purchases, building construction, and appliance purchases are a small proportion of the total stocks of vehicles, buildings, and appliances, the aggregate potential is limited by turnover. Estimating these stocks was beyond the scope of this analysis and I've relied on these aggregate assessments. Based on the results of these studies, I've constrained total potential for energy savings in both the electricity and vehicle markets. These are uncertain parameters in the analysis and vary between 10%-15% of 2025 electricity demand and 10%-12.5% of 2025 fuels consumption. The Technical Appendix contains a detailed description of these estimates.

The potential bureaucratic difficulties to implement this strategy, noted above, are serious issues that I will take up again in the final section of this chapter. At this point, I examine the effects of this strategy to determine if the potential benefits are worth the

challenges of allowing energy efficiency in the policy requirement. Figures 33-40 show results for the costs, benefits, and potential trade-offs with the efficiency strategy.

Figure 33: Welfare Losses in Each Market with Efficiency Strategy

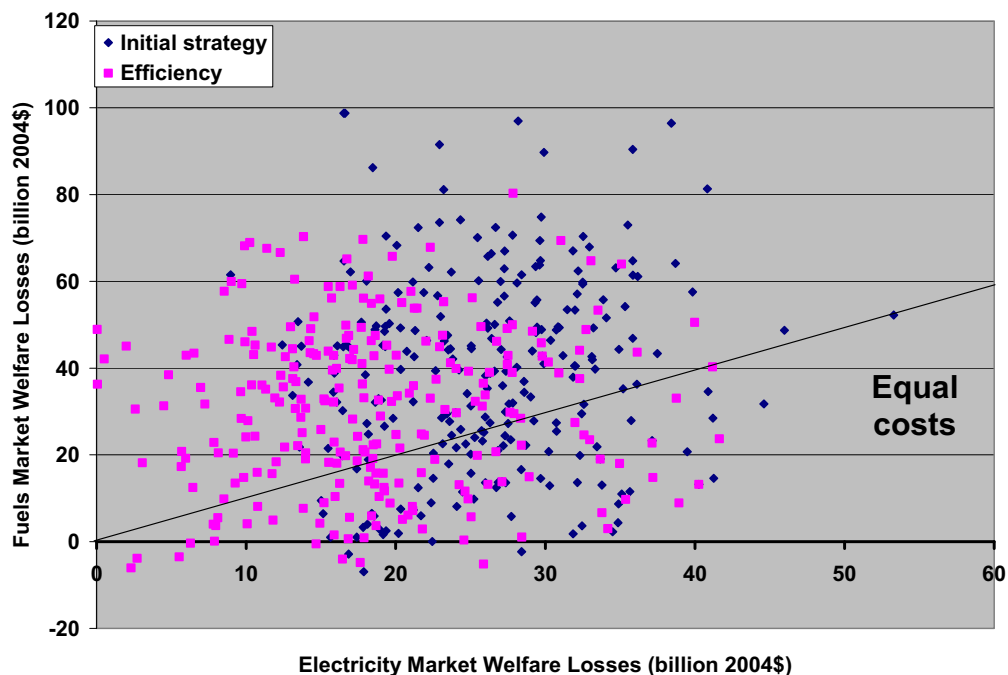


Figure 33 shows the range of welfare losses in each market and compares the results for the efficiency and initial strategies. Corn ethanol remains constrained in this strategy so the only difference in the strategies is an option to substitute energy efficiency measures for renewable energy. The graph shows an overall inward shift in the spread of results, which indicates that energy efficiency can reduce welfare losses over the broad range of uncertainties. The decrease in welfare losses is proportionately larger in the electricity market as the percentage of scenarios with higher welfare losses in the fuels market increases from 68% to 72%. This overall inward shift also differs from the unconstrained ethanol strategy where adding corn ethanol production primarily reduced welfare losses in the high-cost outcomes. With the efficiency strategy, welfare losses decline across a wider range of scenarios. The efficiency strategy does not avoid high-cost outcomes in every scenario though. I also assume a wide range of energy efficiency costs because of large uncertainties in the future costs of this variable. Therefore, efficiency is also uneconomic in some scenarios when renewables are costly. Figure 34 illustrates the change in welfare losses for each scenario in both markets.

Figure 34: Change in Welfare Losses with Efficiency Strategy



The horizontal axis displays the difference in welfare losses between the initial strategy and the efficiency strategy in the electricity market. The vertical axis displays the same information for the fuels market. Again, negative results indicate welfare losses declined in the efficiency strategy. The graph shows some savings in nearly every scenario. The figure displays many scenarios with relatively small welfare changes (less than \$5 billion) in the fuels market where a large number of scenarios cluster near the horizontal axis. However, in a considerable number of scenarios including efficiency reduces welfare costs by more than a \$10 billion, which is a large relative change in the electricity market where the costs of the initial strategy were lower. In the fuels market, efficiency decreases welfare losses by more than \$20 billion when low-cost efficiency opportunities can displace very high-cost biofuels.

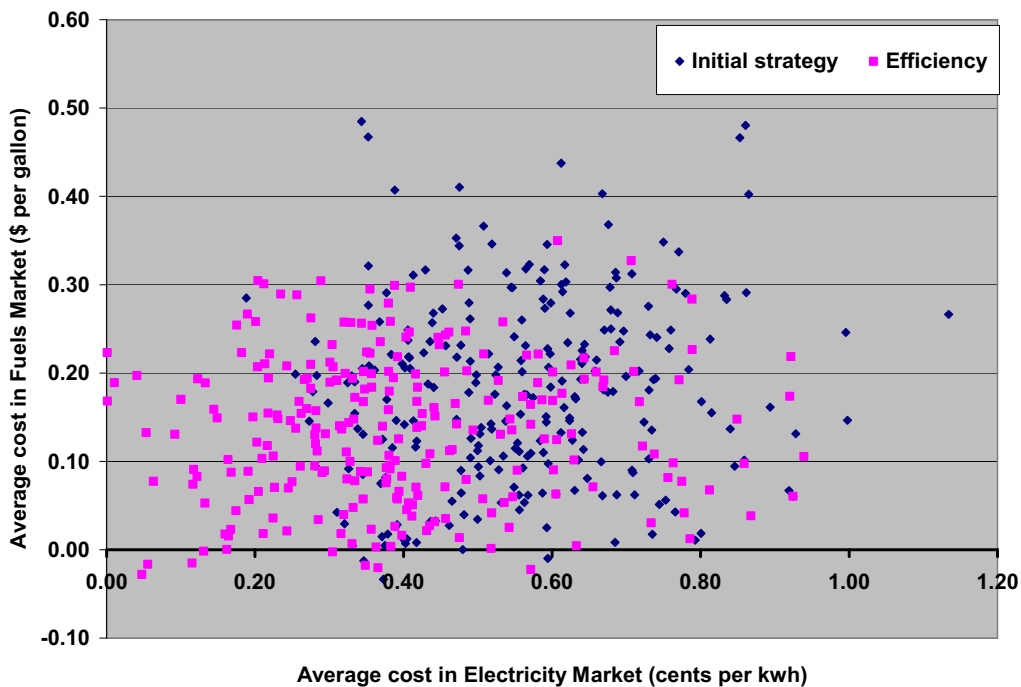
The figure does show a limited number of scenarios in each market with increases in welfare losses. These occur because adding efficiency in the requirement has offsetting effects. In the fuels market, adding efficiency reduces fuels prices, which increases fuels consumption. Higher fuel consumption decreases deadweight losses but an increase in the resource costs of the policy offsets the decrease. The resource costs increase because with higher fuel consumption refiners now need to produce more renewable energy to meet the requirement. Because the supply curve has increasing marginal costs, producing more renewable energy raises total incremental resource costs. In the electricity market, welfare losses increase slightly

in a few scenarios because adding energy efficiency changes how renewable energy substitutes for nonrenewable energy. In the scenarios where welfare losses increase, more biomass power substitutes for coal and the requirement displaces relatively more coal than the corresponding scenario without efficiency. Since the coal market has a more elastic response, fossil fuel costs decline less under these scenarios that displace more coal. This smaller decrease in costs offsets any savings from lower-cost efficiency resources. Of note, in nearly all the scenarios using efficiency the savings from lower-cost resources more than offset the change in fossil fuel costs, and this results indicate that the results are sensitive to the assumptions on how renewable energy and energy efficiency displace nonrenewable capacity and fossil fuels.

Overall, the results show that efficiency reduces welfare losses across the broad range of scenarios as efficiency decreases costs in a large majority of scenarios. The graph also shows potentially very large savings when efficiency can displace a significant amount of costly renewable energy.

Figure 35 compares the average cost of the policy requirement under the efficiency strategy.

Figure 35: Effects of Efficiency Strategy on Average Costs of Policy in Each Market



Similar to the welfare loss graph, allowing energy efficiency to substitute for renewables decreases average costs of policy in both markets for a large number of scenarios. The results indicate that the relative shift in costs is greater in the electricity market as most of the scenarios now meet the criteria for the low-cost outcome. The figure does show that this strategy does not entirely avoid all of the high-cost outcomes, as there are scenarios where energy efficiency is also a costly resource. Overall, the graph shows that the efficiency strategy can reduce the costs of the policy across a broad range of the uncertainties. However, substituting energy efficiency for renewable energy comes with a trade-off with GHG reductions. GHG reductions can decrease with lower welfare losses because the efficiency policy reduces the policy's conservation effect relative to the initial strategy. Figure 36 illustrates the extent of this trade-off.

Figure 36: Change in GHG Reductions and Welfare Losses with Efficiency Strategy



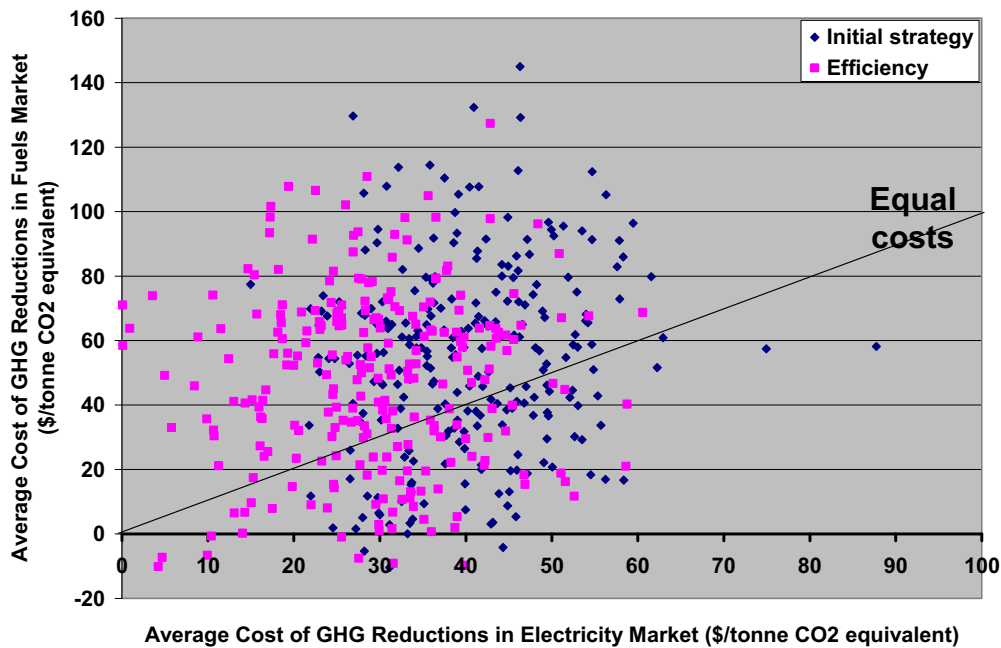
Figure 36 shows reductions in welfare losses on the horizontal axis and the vertical axis displays changes in GHG emissions reductions between the efficiency strategy and initial strategy (negative results indicate lower reductions and positive values are higher reductions). The graph shows increasing energy efficiency in the fuels market reduces welfare costs of the policy but also lowers the reductions in GHG emissions. The graph shows a clear trade-off in

this market as higher reductions in welfare losses are correlated with lower reductions in GHG emissions. This occurs because substituting lower-cost efficiency for high-cost renewable fuels reduces the conservation effects of the policy requirement, and the GHG emissions from lower fuel consumption were a significant part of the total reductions in the initial strategy in many scenarios.

Substituting energy efficiency for renewable energy has two effects in the electricity market, and the net change in emissions depends on the balance of the offsetting effects. The first effect is that lower electricity prices (due to savings from efficiency) decrease the conservation effects of the policy. A second effect is that energy efficiency reduces demand for biomass feedstock and in some scenarios more biomass plants substitute for coal plants. This effect increases GHG reductions and the positive results in the figure show this effect is potentially significant.

Figure 37 shows the average costs of GHG reductions under the efficiency strategy.

Figure 37: Effects of Efficiency Strategy on Average Costs of GHG Reduction

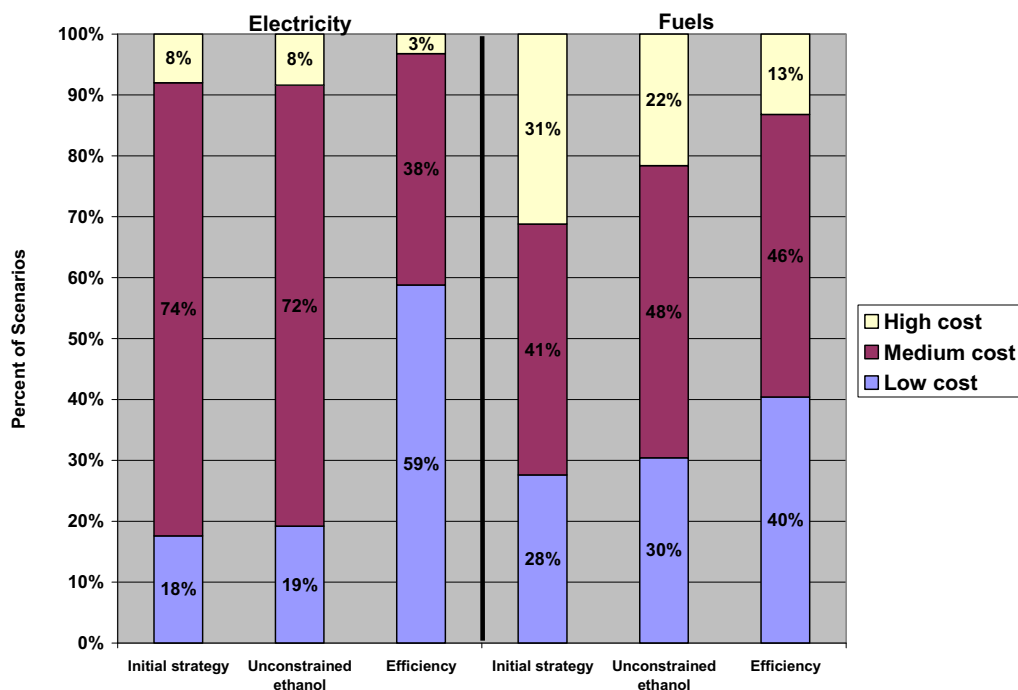


The graph shows that adding energy efficiency decreases the average costs of GHG reductions considerably in many scenarios, particularly in the electricity market. In the fuels market, average costs of GHG reduction also decrease in many scenarios but the change is smaller than

the electricity results. With this shift, the percentage of scenarios with higher costs in the fuels market increases from 66% to 72%, and further exacerbates the cost differences between the two markets per unit of GHG reduction.

With the lower costs for most scenarios under the efficiency strategy, the percentage of scenarios in the low-cost and high-cost outcomes shifts considerably. Figure 38 shows how the efficiency strategy affects these outcomes.

Figure 38: Effects of Efficiency Strategy on Percentage of Low-Cost and High-Cost Outcomes



The first three columns compare the percentage of low- and high-cost outcomes in the electricity market across strategies. The next three columns compare the results for the fuels market. The graph shows that the percentage of low-cost outcomes increases in both markets, and the increase is especially large in the electricity market. In this market, the percentage of low-cost outcomes triples to almost 60%, and the percentage of low-cost scenarios in the fuels market increases to 40%. Correspondingly, the relative percentage of high-cost outcomes declines in both markets. With the efficiency strategy, average welfare losses in the electricity market exceed the high-cost threshold in 3% of the scenarios and the percentage in the fuels market drops to 13%.

Including energy efficiency in the requirement can considerably reduce the policy requirement's costs; however, this cost reduction requires a trade-off with investment in renewable energy technologies. Figure 39 illustrates and quantifies the magnitude of this trade-off.

Figure 39: Renewable Energy Use and Welfare Loss Reductions with Efficiency Strategy

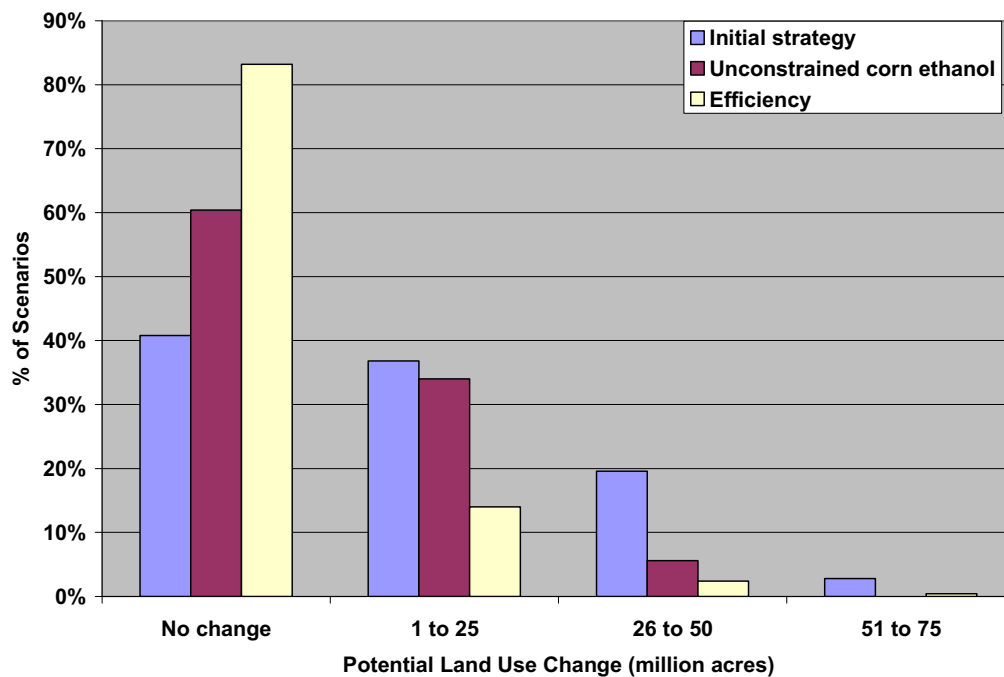


The horizontal axis in Figure 39 shows the reduction in welfare losses and the vertical axis shows renewable energy use in each scenario. The graph shows the correlation between high cost reductions and lower renewable energy penetration. The largest cost reductions require a decrease in renewable energy use to near 15% penetration. However, the results indicate that efficiency can significantly reduce costs with just a few percent increase, particularly in the electricity market. The graph shows that substituting approximately 5% of the renewable energy with energy efficiency can realize a large portion of the potential savings and still would double renewable energy penetration from its current level. The results in the fuels market indicate greater levels of efficiency need to displace renewables to achieve comparable cost reductions. While this trade-off may decrease investment in new biofuels, even reaching 15% renewables in this market is a substantial increase from the current level.

The graph also shows an interaction effect between the two markets. Several scenarios in both markets achieve lower welfare losses while renewable energy use remains at 25%. Welfare losses decline without adding efficiency because efficiency in the other market decreases total demand for biomass and the price of biomass declines. The result suggests that a widespread efficiency program may not be needed to realize many of the potential benefits. A targeted efficiency program triggered by high renewable energy costs in the fuels market could capture many of the benefits of the program while limiting the trade-offs and difficulties of managing an efficiency program.

A final comparison assesses how efficiency affects potential land use change that could occur with high biomass demand. Figure 40 compares the strategies across the range of land use changes.

Figure 40: Effects of Efficiency Strategy on Potential Land Use Change



The figure shows that adding efficiency decreases biomass feedstock demand and reduces land use change. The efficiency strategy more than doubles the percentage of scenarios with no land use change in comparison to the initial strategy. Accordingly, the relative percentage of scenarios in the other bins declines and now over 90% of the scenarios involve land use change less than 25 million acres. However, the efficiency strategy does not completely eliminate the

potential for high land use change outcomes. There are still a limited number of scenarios with land use changes over 50 million acres.

The results presented in this section show that including efficiency can decrease costs across a broad range of the scenarios. The efficiency strategy decreases the risk of costly outcomes but this decrease comes at the expense of potentially lower reductions in GHG emissions and development of renewable energy. The next section will now assess any interaction effects with the unconstrained corn ethanol and efficiency strategies.

Joint Corn Ethanol and Efficiency Strategy Reduces Trade-offs

The joint corn ethanol and efficiency strategy allows unconstrained corn ethanol production and energy efficiency to qualify towards the 25% requirement. The joint strategy provides a more diverse set of resources to meet the requirement while potentially mitigating some of the unintended consequences and trade-offs seen in the individual unconstrained ethanol and efficiency strategies. Figure 41 shows the welfare losses in each market.

Figure 41: Welfare Losses in Each Market under Joint Strategy

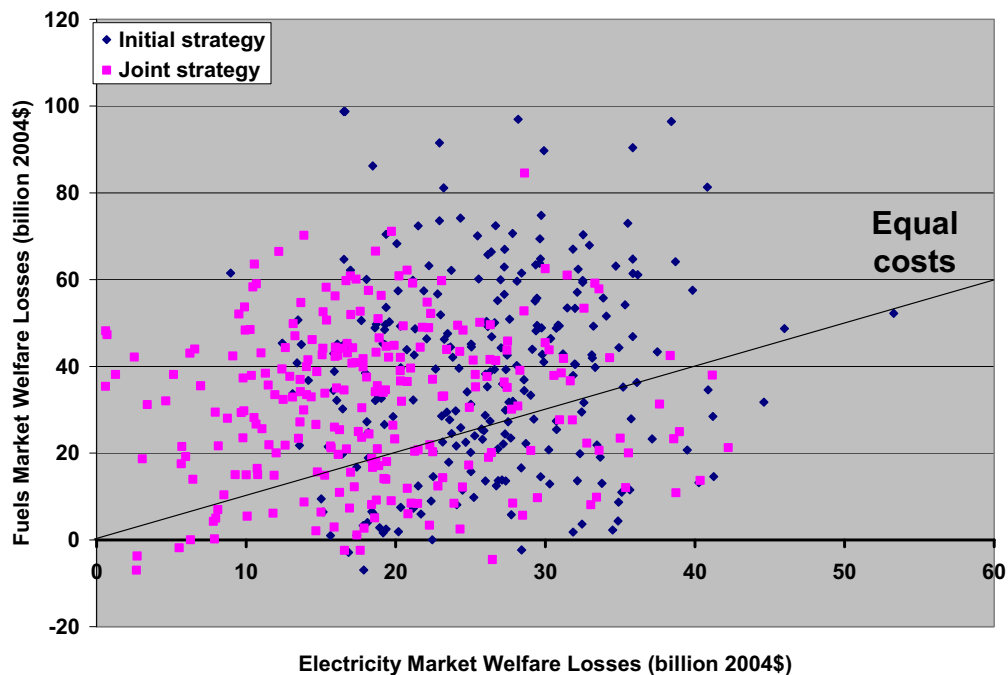
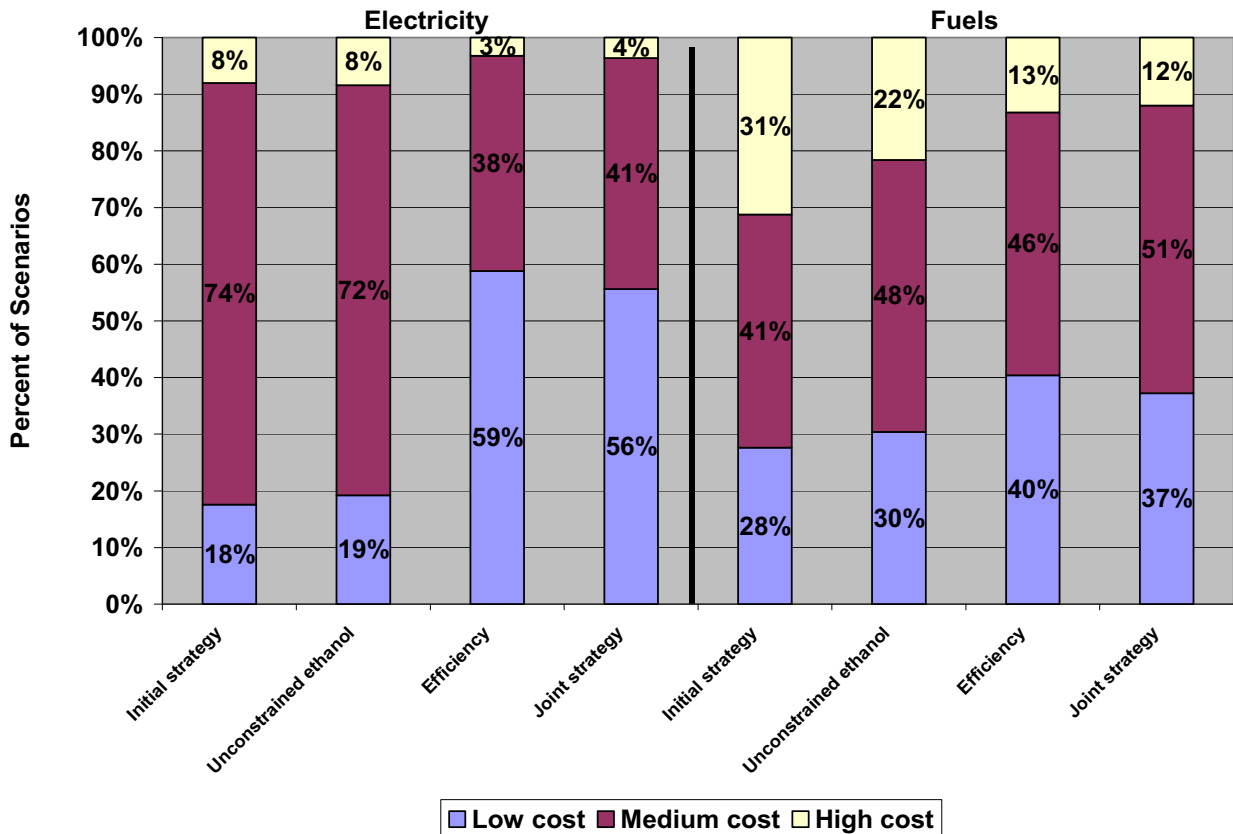


Figure 41 looks similar to the scatter plot for the efficiency strategy. The overall welfare losses in the fuels market decline slightly relative to the efficiency strategy in many scenarios. The welfare losses decline as corn ethanol offers some additional cost-effective opportunities in the fuels market after exhausting the competitive potential for energy efficiency. However, as shown earlier, increasing corn ethanol production can raise costs in the electricity market as the higher demand for natural gas offsets savings from lower biomass demand. The effects of the joint strategy are best seen in the figure comparing the percentage of low-cost and high-cost outcomes.

Figure 42: Effects of Joint Strategy on Percentage of Low-Cost and High-Cost Outcomes



The joint strategy modestly decreases high-cost outcomes in the fuels market, by 1%, but increases this percentage slightly in the electricity market. For the low-cost outcome, the percentage of outcomes decreases slightly in both the electricity and fuels markets. The additional corn ethanol production increases natural gas demand and negatively affects the

electricity market. The marginal decrease in low-cost outcomes in the fuels market occurs as corn ethanol production increases deadweight losses from corn price increases and affects some scenarios at the threshold of the low-cost and medium-cost outcomes. Overall, the figure shows that the joint strategy marginally lowers the percentage of high-cost cases in the fuels market but negatively affects the electricity market. The joint strategy also reduces some of the transfer effects that are likely to spur opposition to a 25% requirement. Figure 43 shows the effects of the joint policy on surplus transfers.

Figure 43: Surplus Transfers Under Initial and Joint Strategies

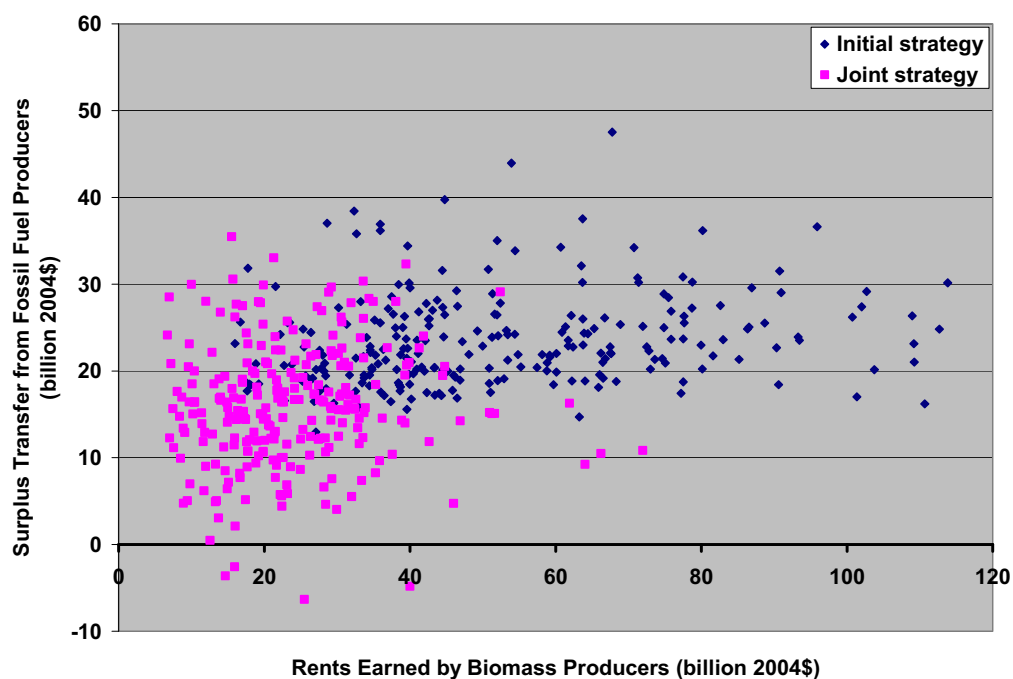
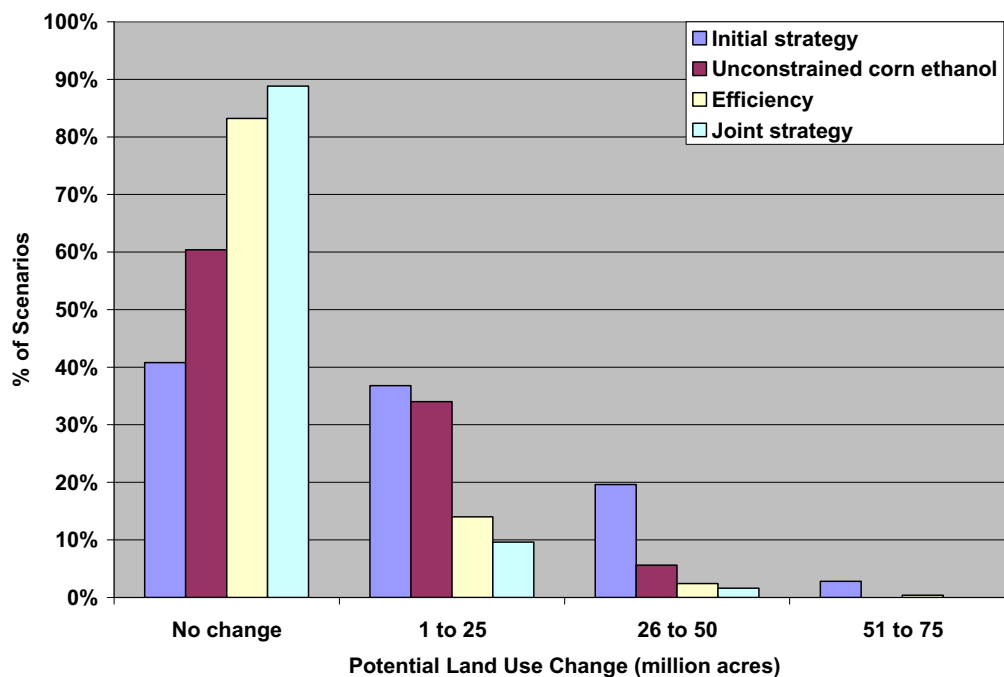


Figure 43 compares the surplus transfer results for the initial strategy, shown in Figure 17, with the results under the joint strategy. The graph shows that increasing energy efficiency and corn ethanol production can mitigate some of the scenarios with large surplus transfers from fossil fuel producers and gains for biomass producers. The graph shows a considerable inward shift in the results reflecting lower price increases in the biomass market and smaller price declines in the fossil fuel markets. The graph shows a few scenarios with negative surplus transfers for fossil fuel producers. This occurs because net natural gas demand actually increases and is a result of an interaction between including energy efficiency and higher corn ethanol production. Including energy efficiency in the policy requirement lowers the amount of

natural gas displaced by renewable electricity, relative to the initial strategy, and adding corn ethanol can actually result in net increases in a few scenarios. Finally, while the joint strategy lowers surplus transfers in most scenarios, the surplus transfers from fossil fuel producers still range between \$10 and \$30 billion in most scenarios and these producers are still likely to vigorously oppose a policy leading to losses of this magnitude.

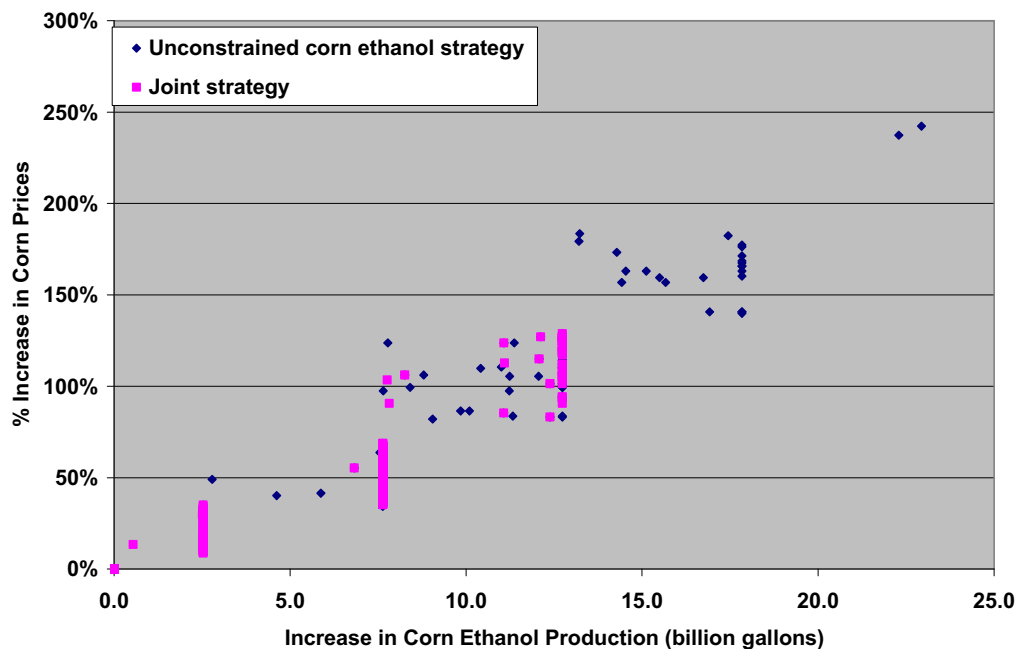
An important unintended consequence shown earlier is the potential land use change induced by biomass demand. Figure 44 shows the percentage of land use change across the strategies.

Figure 44: Effects of Joint Strategy on Potential Land Use Change



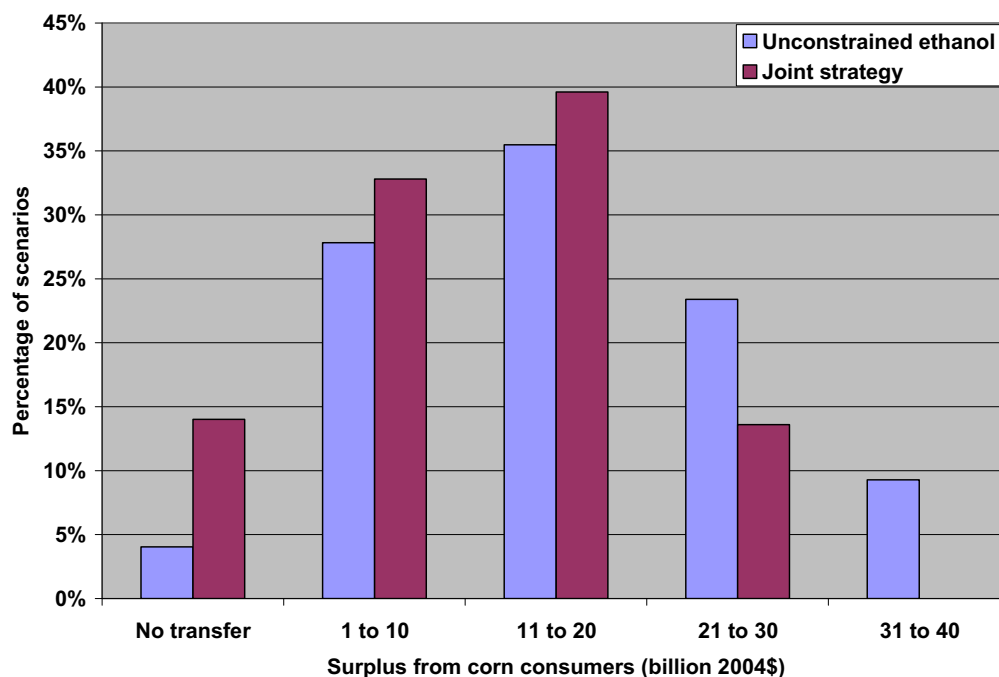
The joint strategy further decreases demand for biomass feedstock and any resulting land use changes needed to meet demand. In the joint strategy, the no land use change outcome increases to almost 90% of the scenarios. When adding the scenarios with relatively limited land use change less than 25 million acres, nearly all the scenarios require land use change less than 25 million acres. The joint strategy also eliminates the scenarios with the highest land use changes over 50 million acres. In addition to mitigating the extreme outcomes on land use change, the joint strategy limits some of the largest impacts on the corn market. Figure 45 compares the effects of the joint and individual unconstrained corn ethanol strategies on corn prices.

Figure 45: Corn Ethanol Production and Corn Price Change under Joint Strategy



The figure shows that the joint requirement reduces the number of scenarios with the highest increases in corn ethanol production and corn prices. The number of scenarios with less than 10 billion gallons of new ethanol production are relatively close but the joint strategy eliminates the scenarios with production over 13 billion gallons and their associated price increases. The lower levels of corn ethanol production and smaller corn price increases also affect the surplus transfer between corn consumers and producers. Figure 46 compares the range of results for this metric between the unconstrained corn ethanol and joint strategies.

Figure 46: Effects of Joint Strategy on Surplus Transfer in Corn Market



The graph shows that the joint strategy reduces the surplus transfers in most scenarios and eliminates the extreme outcomes with transfers over \$30 billion. The graph shows that the percentage of scenarios with no transfers (and no increased corn ethanol production) increases as well as the scenarios with transfers less than \$20 billion. The increase in scenarios with lower surplus transfers comes from reducing scenarios with transfers over \$20 billion.

Overall, the joint strategy realizes many of the cost savings of the efficiency strategy but limits some of the trade-offs and unintended consequences of both of the efficiency and unconstrained ethanol strategies. By combining efficiency with higher levels of corn ethanol, the joint strategy avoids the scenarios with the most extreme increases in corn prices and surplus transfers. The joint strategy also limits some of the scenarios where efficiency displaces a significant amount of renewable energy production. Figure 45 shows that corn ethanol production increases but to lower levels near 10 billion gallons. While the joint strategy has significantly lower welfare losses than the initial strategy in most scenarios, high cost outcomes are still possible. The next strategy uses a safety valve to explicitly limit the policy's costs and Figures 47-52 show the effects of this strategy.

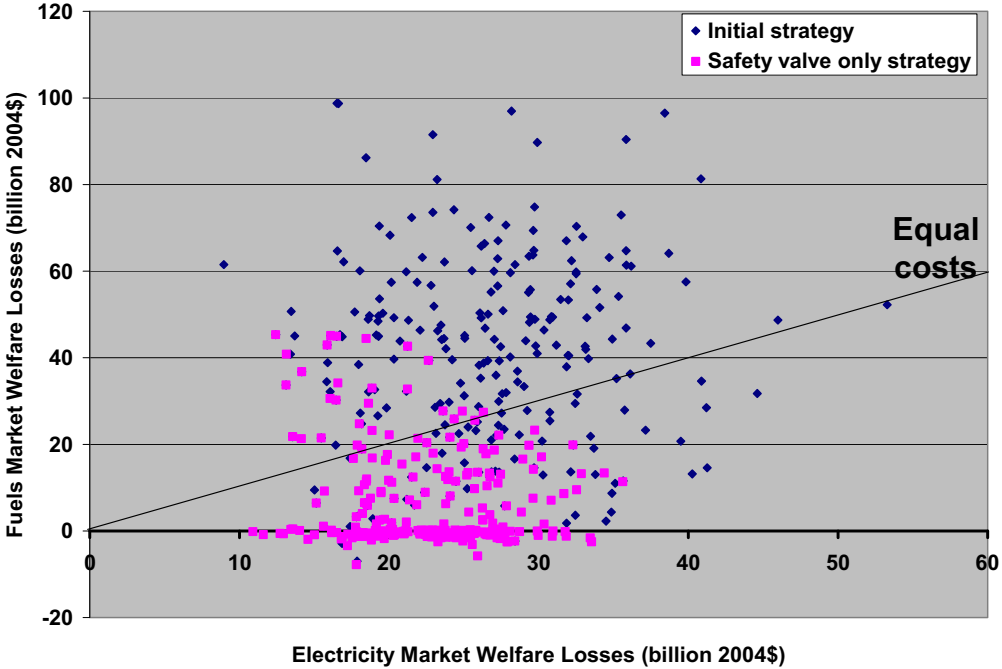
Safety Valve-Only Strategy Contains Welfare Losses but Refiners May Incur Costly Fees

In this strategy, the goal of the safety valve is to limit the policy's average costs below the high-cost outcome threshold. To accomplish this, I model a program where the government sells renewable energy credits in a trading market at a fixed price. Renewable energy expands and credit prices rise until the credit price reaches the safety valve price. Then, refiners and utilities can purchase permits from the government at the safety valve price to cover the remaining portion of the 25% requirement. I implement this policy option in the model by placing a constraint on the incremental costs of energy, which is equivalent to the credit price in a trading market. Both in the model and in a trading market, limiting the price in the trading market is an indirect mechanism to control the net welfare losses of the policy because the actual net effects vary depending on the deadweight losses. For this reason, the safety valve can contain welfare losses from an extreme range but in some scenarios they can rise slightly over the threshold level.

To estimate the limit I need on incremental costs to achieve the goal for average costs, I regress the results for policy's average costs under the initial strategy on the incremental costs of renewables substitution and plant-gate biofuels costs for that strategy. Through this, I establish threshold values in the electricity market of 6.5 cents per kwh and \$3.00 per gallon gasoline equivalent for the plant-gate cost of biofuels (the EIA estimates average state and federal taxes, distribution costs, and retail margins add another \$0.61 per gallon for retail costs). This plant-gate cost results in a retail price of \$3.61 per gasoline gallon equivalent. Recent experience with gasoline prices over \$4.00 per gallon indicates that this may be a reasonable level for the threshold. As gasoline prices have exceeded this level, consumers have changed their preferences for large vehicles with low fuel economy to vehicles with greater fuel economy. Recent polls also suggest that public support for environmental restrictions on offshore oil exploration and development is declining. This evidence suggests that consumer willingness-to-pay for renewable energy may be limited when costs near this threshold.

The next set of graphs illustrates the results for the safety valve-only strategy. This strategy does not include the options for higher corn ethanol production and energy efficiency shown in the two previous strategies, but the final all-combined strategy does include these resources. Figure 47 shows the welfare losses in both markets.

Figure 47: Welfare Losses in Each Market with Safety Valve-Only Strategy



The graph shows that the safety valve-only strategy limits welfare losses considerably in comparison to the initial strategy. In fact, many of the welfare losses in the fuels market lie along the horizontal axis, which indicates the safety valve limited any new biofuels production because their plant gate costs exceeded the safety valve level. In the remaining scenarios, welfare losses decline significantly in the fuels market. The maximum welfare loss was \$45 billion, which is less than half the maximum under the initial strategy. The percentage of scenarios with higher welfare losses in the fuels market also drops substantially from 68% to 11%. The graph shows less drastic reductions in the electricity market. The highest welfare loss in this market was \$36 billion. Another measure of the effect of the safety valve is the percentage of scenarios constrained by this limit. In the electricity market, 12% of the scenarios reached this limit; whereas, the safety valve constrained renewable energy development in 75% of the scenarios in the fuels market. Overall, the graph shows that the safety valve-only strategy contains welfare losses effectively but drastically limits renewable energy production in many scenarios, particularly in the fuels market. Figure 48 shows the results for the average costs of the policy requirement under the safety valve-only strategy.

Figure 48: Effects of Safety Valve-Only Strategy on Average Costs of Policy in Each Market

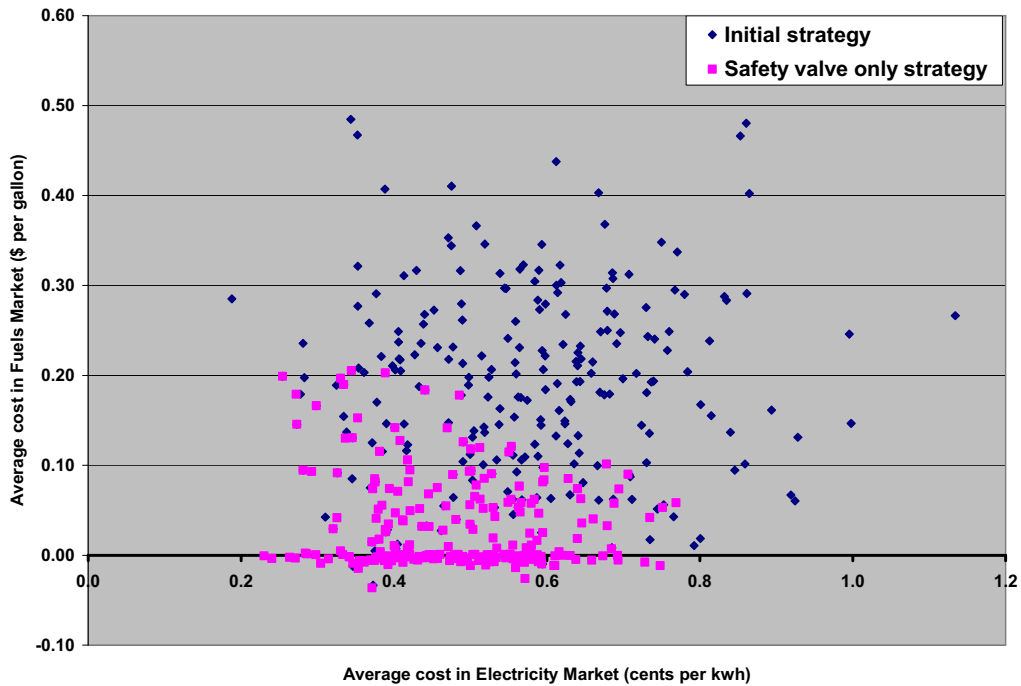
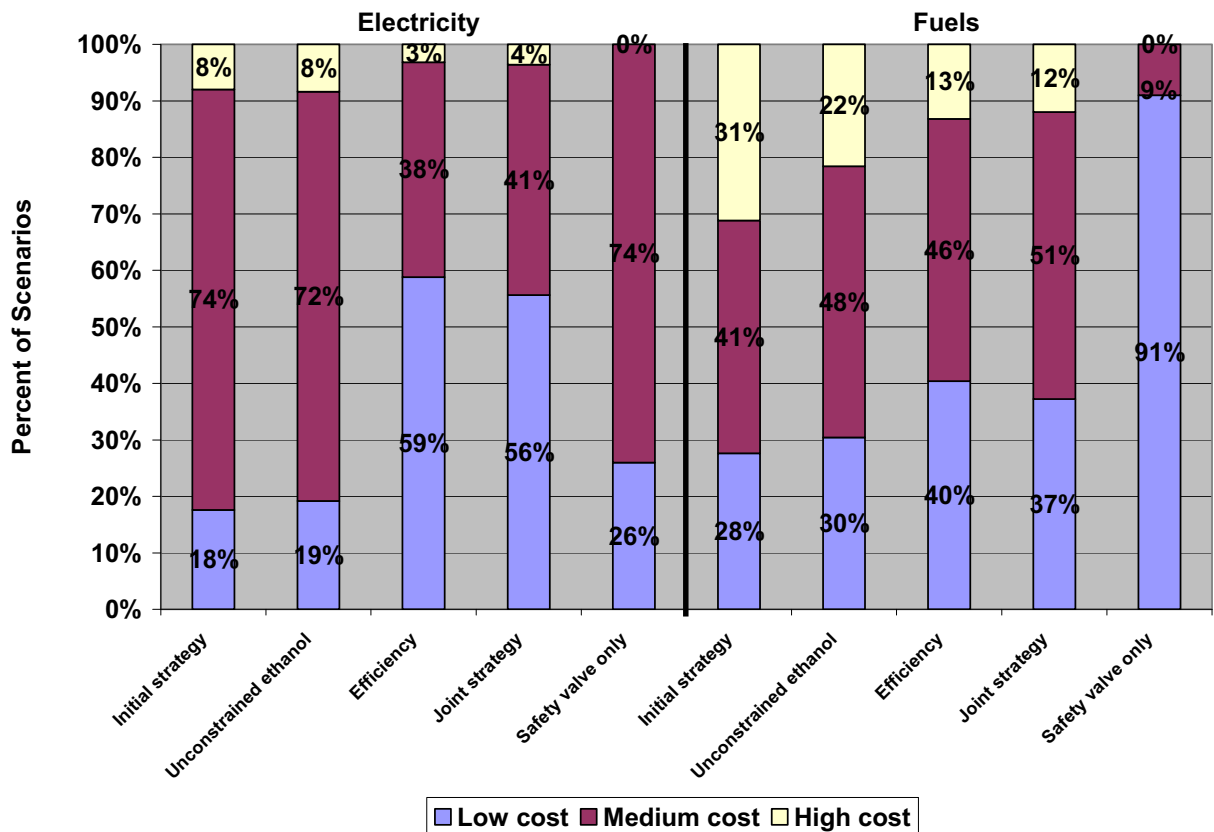


Figure 48 shows that the safety valve contains the average costs of the renewable energy requirement within the high-cost thresholds in both markets. No scenarios exceed the high-cost threshold of 0.8 cents per kwh in the electricity market and \$0.23 per gallon in the fuels market. The graph also shows the safety valve significantly decreases average costs of the requirement in the fuels market and a majority of the scenarios now cost below the low-cost threshold of \$0.11 per gallon. The large increase in low-cost outcomes occurs primarily because the safety limits any new biofuels production in many scenarios. Figure 49 shows the exact percentage of scenarios within each threshold and compares these results to the other strategies.

Figure 49: Effects of Safety Valve-Only Strategy on Percentage of Low-Cost and High-Cost Outcomes



The figure shows the percentage of scenarios in each outcome. The first five columns compare strategies in the electricity market and the next five show the results for the fuels market. The safety valve-only strategy eliminates the high-cost outcomes in both markets, which is shown by the 0% label at the top of both columns corresponding to this strategy. This strategy also significantly increases the percentage of low-cost outcomes in the fuels market. With the safety valve-only strategy, 91% of the scenarios resulted in average welfare losses below the low-cost threshold; however, this result comes with a large trade-off because many of the scenarios added no new renewable energy production. In the electricity market, the safety valve-only strategy increases the number of low-cost outcomes by 8% in comparison to the initial strategy, but this percentage of low-cost outcomes is lower than under the efficiency and joint strategies. This is expected because the safety valve primarily affects the high-cost scenarios, which were only 8% of the scenarios under the initial strategy. Overall, the results show the safety valve can contain costs but these limits come with potentially large trade-offs in GHG reductions, lowering oil consumption, and renewable energy development. Further results

also show refiners and utilities pay high safety valve fees. The remaining graphs show these effects.

Figure 50: Renewable Energy Use and Welfare Loss Reduction with Safety Valve-Only Strategy

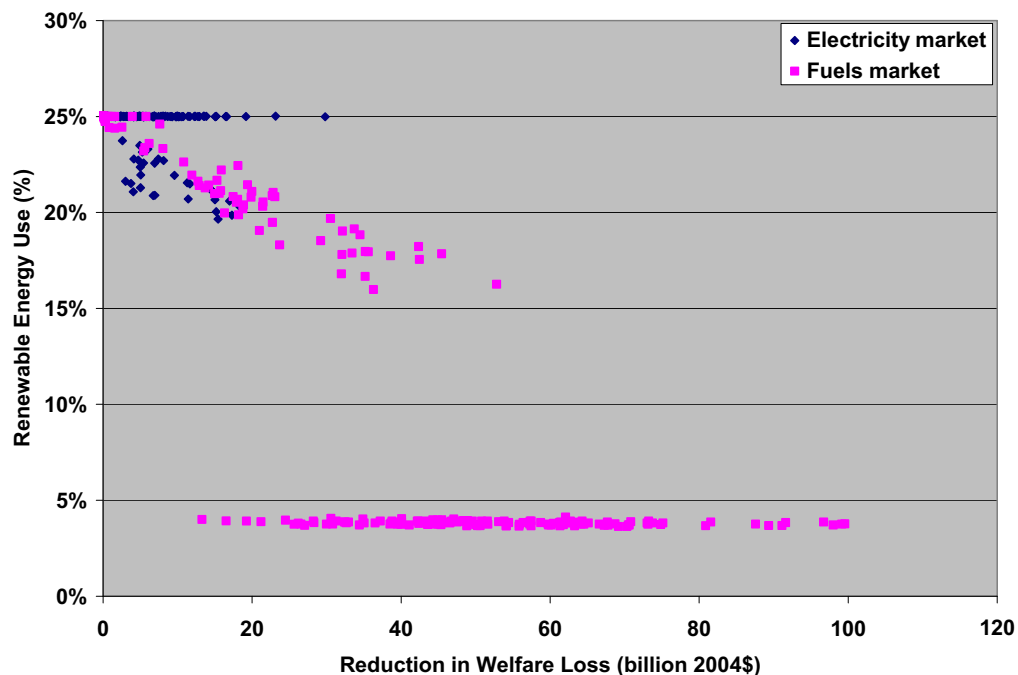


Figure 50 most prominently shows the safety valve’s severe constraint on renewable energy production in the fuels market. In all of the scenarios with renewable energy use below 25%, the safety valve is a binding constraint, and the graph shows three distinct sets of scenarios. In all the scenarios in the lower portion of the graph, the safety valve limits any new renewable fuels production, and the reduction in welfare losses is considerable. The graph also shows scenarios where the safety valve limits renewable production between 15% and 25% and is a less severe constraint. The graph also shows that the safety valve-only strategy affects the electricity market in limited number of scenarios.

This pattern of results illustrates three broad scenarios that affect the policy requirement, which I describe as scenarios with low, medium, and high renewable energy costs. In the low-cost scenarios, shown in the points with 25% renewable energy use, the safety valve has little or no effect on the result. In the medium-cost scenarios, the safety valve limits renewable energy use up to about 10%. The graph shows this strategy considerably reduces costs with a modest trade-off in renewable energy development. Finally, in the high-cost

scenarios, all new renewable energy costs more than the safety valve and this strategy limits all new production. I further discuss these three broad scenarios in the analysis on the all-combined strategy and in summarizing the robustness of the strategies to uncertainty in future energy markets.

Figure 51 shows the potential trade-offs with limiting GHG emissions under the safety valve-only strategy.

Figure 51: Greenhouse Gas Reductions under Safety Valve-Only Strategy

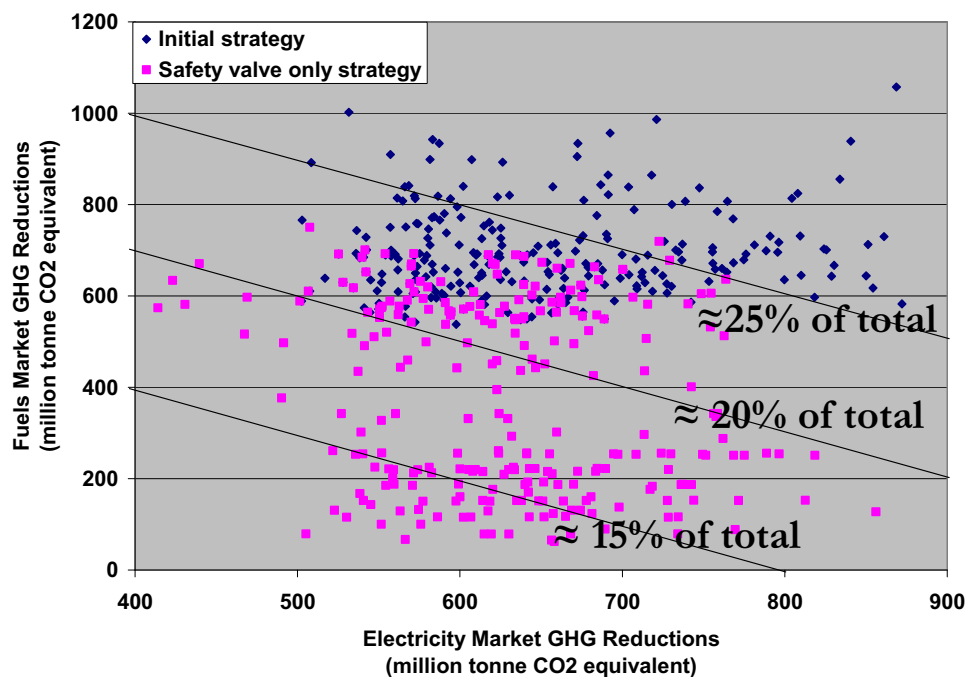


Figure 51 shows the GHG reductions in the electricity and fuels markets under the safety valve-only strategy. The graph shows a set of scenarios where the GHG reductions under both strategies overlap. These are scenarios where the safety valve was not binding and had little effect on the outcome. A large number of scenarios in the fuels market have significantly lower GHG reductions. These results indicate where the safety valve limited all renewable energy production in this market. Even with no additional renewables in the fuels market, the safety valve-only strategy lowers GHG emissions in this market because the fuels prices rise to cover the cost of safety valve permit fees and these higher prices induce a conservation effect. A final group of scenarios result in considerably lower GHG reduction in the electricity market. These are also scenarios where the safety valve substantially reduced renewable electricity production. As noted by the percentage of scenarios affected by the safety valve, this is a relatively limited

number of cases in this market. The graph does show that even in cases where the safety valve effectively limits any renewable fuels production that policy requirement lowers GHG emissions approximately 15% because of the large reductions remaining in the electricity market. The final graph for this strategy shows the safety valve payments paid by refiners and utilities.

Figure 52: Safety Valve Payments

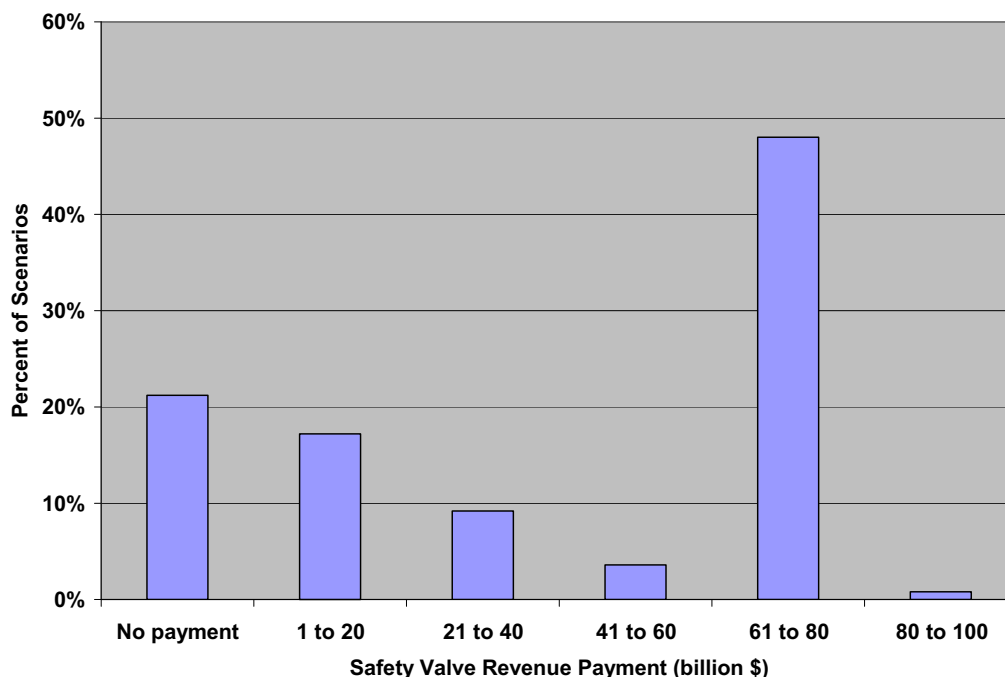


Figure 52 groups the safety valve payments into 6 different bins shown on the horizontal axis. The vertical axis shows the percentage of scenarios with safety valve payments within each bin. The first bin is all the scenarios with no payment because the safety valve constraint is not binding. The remaining bins increase in \$20 billion increments and show the percentage of scenarios within the bin. In just over 20% of the scenarios, the renewable energy costs remained below the safety valve price and refiners and utilities paid no fees. In the next three bins with safety valve revenues increasing successively up to \$60 billion, the graph shows a declining percentage of scenarios within each bin, and these scenarios reflect the range of results shown in Figure 51 where the safety valve constrained renewable production between 15% and 25%. Collectively, these account for about 30% of scenarios. The next bin captures nearly all the scenarios with no biofuels production and safety valve payments range from over \$60 billion to \$80 billion. This bin contains 48% of the scenarios. Finally, the last bin with payments up to \$100 billion contains 2% of the scenarios with extremely high payments under this strategy. In

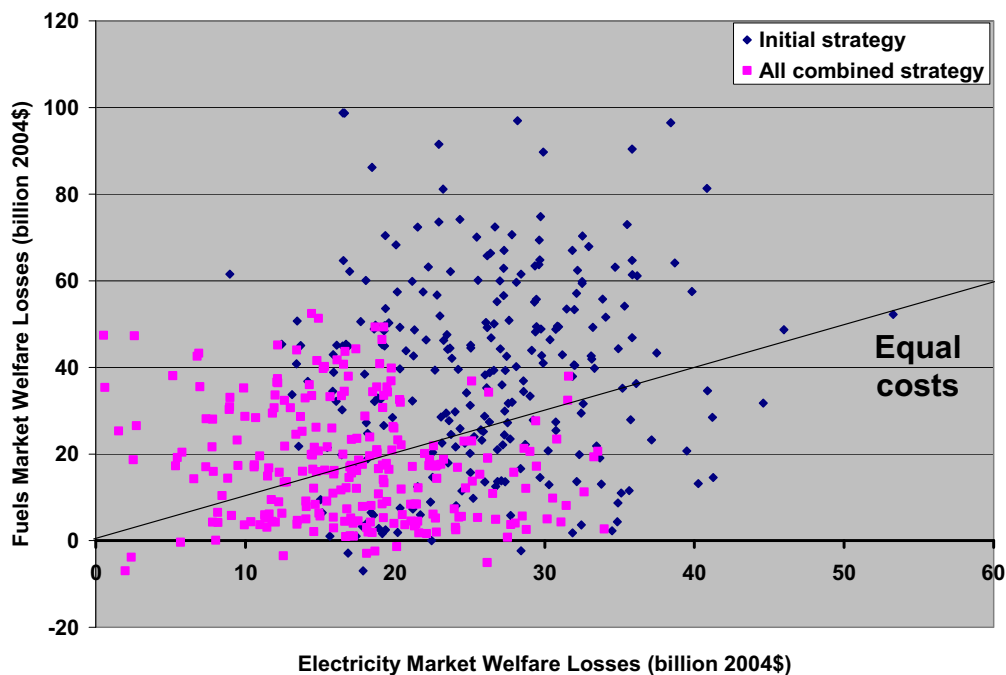
sum, this final result shows the key trade-off with this strategy; the safety valve contains the policy’s welfare losses but forces refiners and utilities to pay possibly considerable permit fees. In the scenarios with no additional biofuels production, the policy requirement becomes a pure tax on refiners and this result has important political implications. Refiners and utilities are likely to lobby vigorously in these scenarios to adjust or remove the policy requirement.

I now assess the final all-combined strategy that includes all the components of previous strategies. Figures 53-60 show the results for this strategy.

All-Combined Strategy Limits Welfare Losses and Mitigates Unintended Consequences

The results show the all-combined strategy can limit welfare losses similar to the safety valve-only strategy, and reduces many of the extreme unintended consequences seen in the individual strategies. Figure 53 displays the welfare losses under this strategy.

Figure 53: Welfare Losses in Each Market with All-Combined Strategy



The figure illustrates that the all-combined strategy successfully limits costs in both markets while allowing some renewable energy production in nearly all scenarios. The maximum welfare loss in the electricity market declines to \$34 billion, which is a 35% decline from the highest loss in the initial strategy. Furthermore, the large majority of cases now incur

welfare losses less than \$20 billion. The all-combined strategy limits costs more significantly in the fuels market. The maximum welfare loss is now \$52 billion, which is nearly a 50% decrease from the highest welfare loss under the initial strategy. The majority of welfare losses are far below the maximum under the initial strategy as the all-combined strategy limits welfare losses to less than \$30 billion in the majority of scenarios. The percentage of scenarios with higher welfare losses in the fuels market also drops from 68% to 46%. These are significant decreases in welfare losses in most scenarios and limit the average costs of the policy requirement below the high-cost threshold in nearly all scenarios. Figure 54 shows the range of results for the average costs of the policy requirement.

Figure 54: Effects of All-Combined Strategy on Average Costs of Policy Requirement

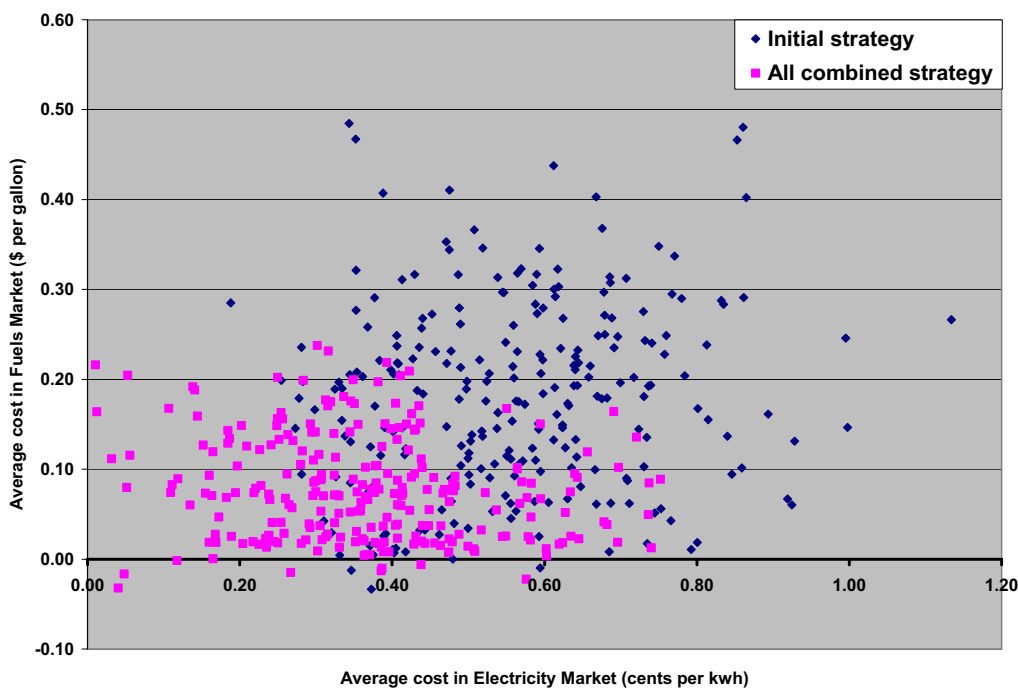
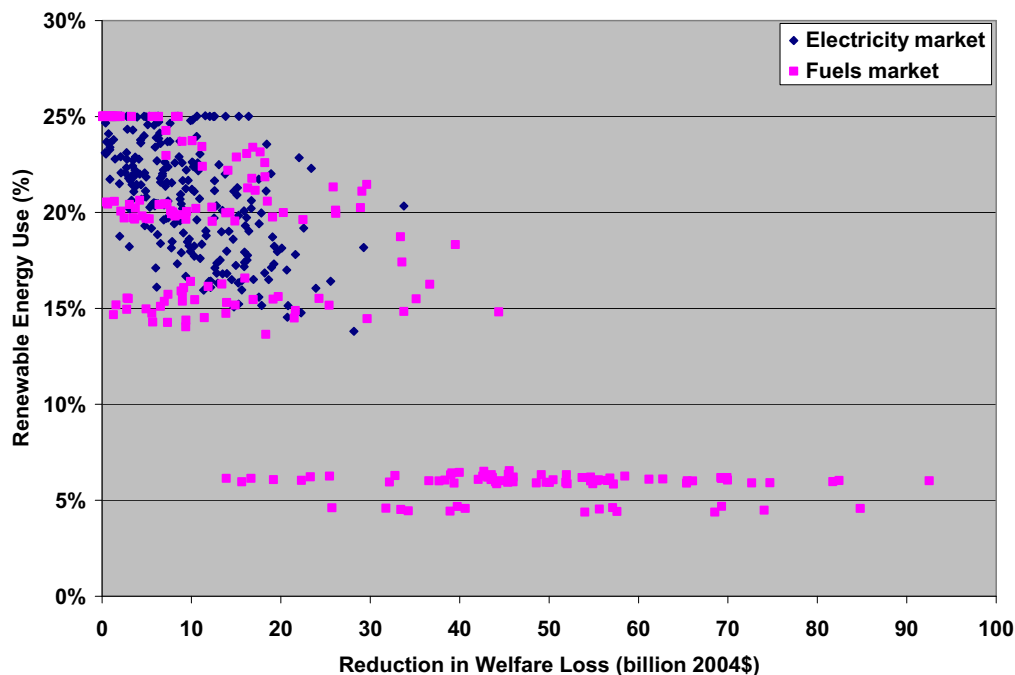


Figure 54 demonstrates that the all-combined strategy successfully avoids the high-cost outcomes in nearly every scenario. This strategy contains average costs of policy below 0.8 cents per kwh in the electricity market and 23 cents per gallon in the fuels market (the high-cost thresholds) in all but two of the scenarios. However, the all-combined strategy still entails some trade-offs with other policy objectives, but the trade-offs are not as large as in the individual strategies. The remaining figures illustrate these effects. Figures 55 and 56 compare the

reduction in welfare losses in each market with the level of renewable energy and GHG emissions reductions.

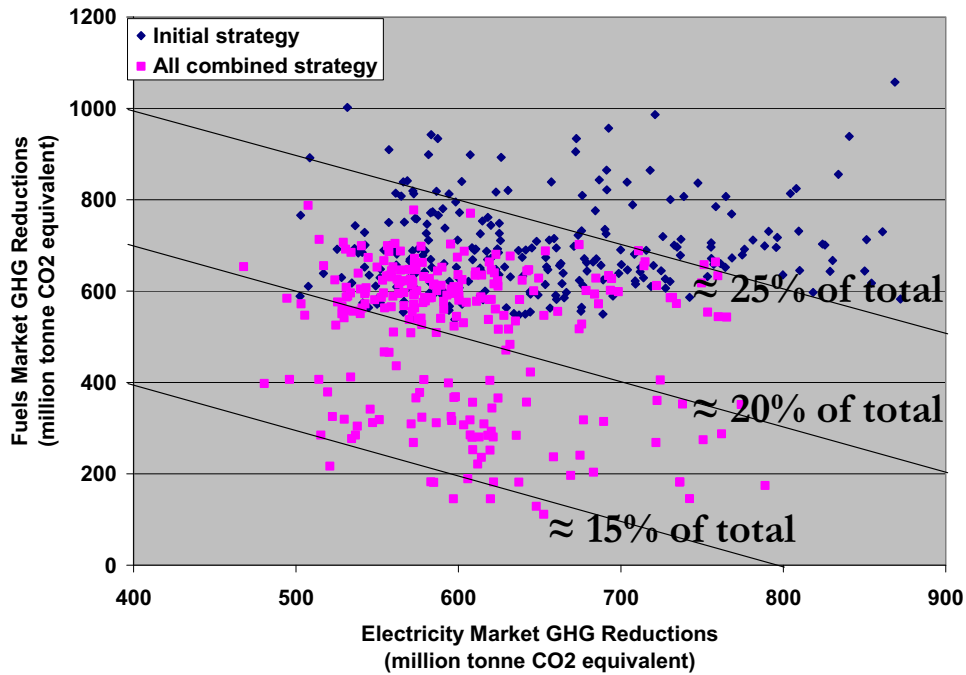
Figure 55: Comparison of Renewable Energy Use with Welfare Loss Reductions under All-Combined Strategy



The graph illustrates the combined strategy considerably reduces welfare losses in both markets relative to the initial strategy but does not limit renewable fuels production as severely as the safety valve-only strategy. Of note, renewable energy use can now decrease below 25% for two reasons. Substituting energy efficiency decreases renewable energy use and the safety valve can also lower production. Under the all-combined strategy, the safety valve constrained electricity production in only 6% of the scenarios and 42% of the scenarios in the fuels market. This is a considerable reduction in the number of scenarios constrained in the fuels market and the safety valve is not as severe a constraint because higher corn ethanol production and energy efficiency lower the costs of meeting the 25% requirement. The figure still shows many scenarios with severe limits on renewable energy production in the fuels market with the spread of points near 5%. In 31% of the scenarios, the safety valve limited renewable fuels production to this level, but even in these scenarios corn ethanol producers increase output by about 3

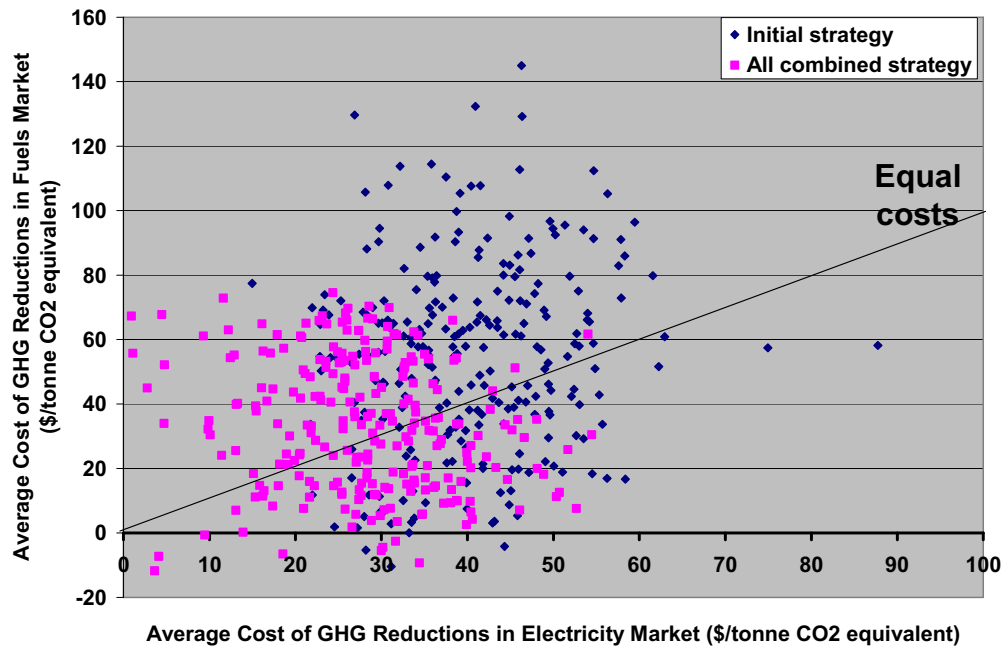
billion gallons. A second trade-off with the all-combined strategy is lower GHG emissions reductions, and Figure 56 shows this trade-off.

Figure 56: Greenhouse Gas Reductions under All-Combined Strategy



The graph shows two sets of outcomes. The first set of outcomes is the large number of scenarios with GHG reductions between 20% and 25%. These are scenarios with low to moderate renewable energy costs. In these scenarios, the all-combined strategy can lower welfare losses relative to the initial strategy but still result in large GHG reductions. The second set of outcomes is the results between 15% - 20% GHG reductions. In most of these scenarios, the safety valve constrains renewable energy production near 5%, and these were scenarios with high renewable energy costs. Despite the lower GHG reductions, most scenarios still reduce emissions by at least 15% from total projected emissions by the electricity and transportation sectors. I now compare the average costs of GHG reductions between the initial and combined strategies in Figure 57.

Figure 57: Effects of All-Combined Strategy on Average Costs of GHG Reduction



The figure shows that the all-combined strategy also substantially reduces the average costs of GHG reductions, particularly in the fuels market. Now, in nearly all the scenarios in the electricity market average costs of GHG reduction remain below \$50 per tonne and a large portion of the scenarios cost below \$30 per tonne. In the fuels market, the combined strategy reduces average costs of GHG reduction in all the scenarios below \$80 per tonne, which is a nearly 50% decrease from the highest costs in the initial strategy. The average costs of GHG reductions in the fuels market still exceed the electricity market in 54% of the scenarios. Therefore, even with substantial cost reductions in the fuels market, the policy requirement still costs more per unit of GHG reduction relative to the electricity market in the majority of scenarios. Similar to the average costs, the incremental costs of GHG reductions also decrease in most scenarios with the all-combined strategy.

Figure 58: Effects of All-Combined Strategy on Incremental Costs of GHG Reduction

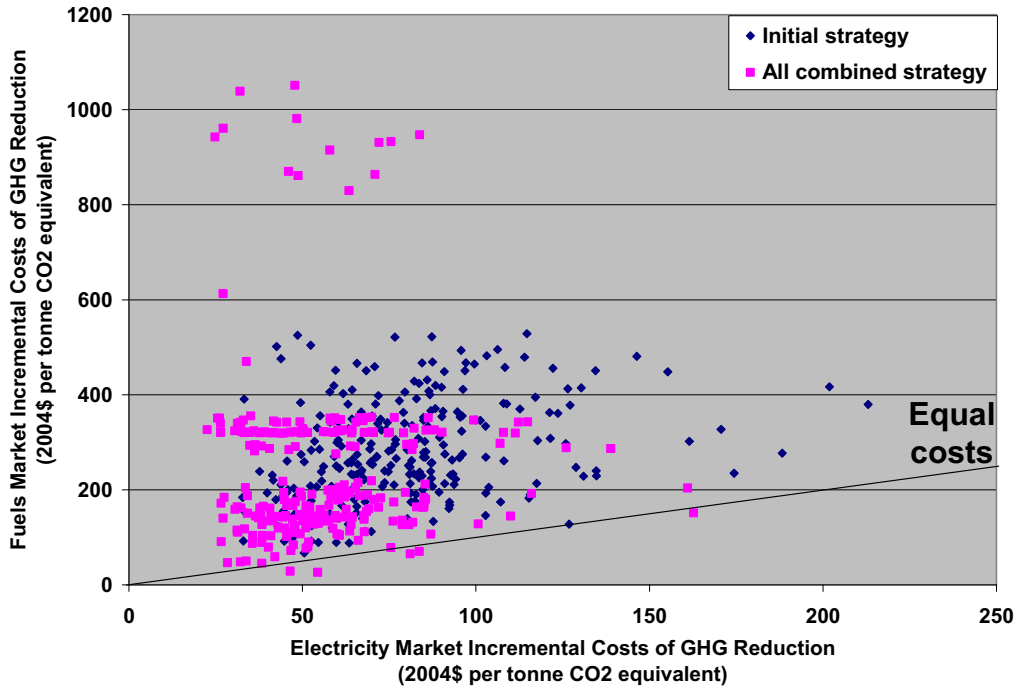
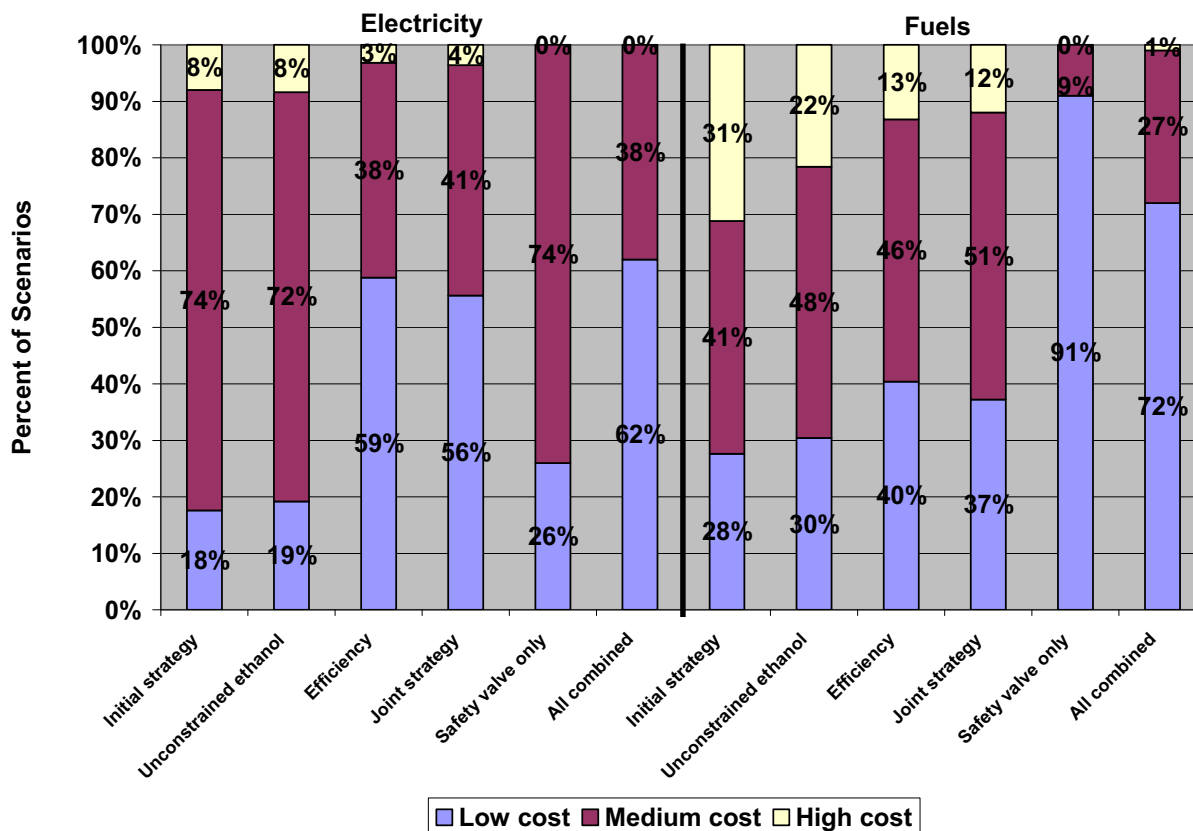


Figure 58 compares the incremental cost of GHG reductions from the marginal renewable energy source between the initial and all-combined strategies. The graph shows three sets of points in the all-combined strategy. One cluster of points with incremental costs of GHG reduction in the fuels market below \$200 per tonne. These were scenarios that were not severely constrained by the safety valve (renewable energy use greater than 15%). A second cluster of points near approximately \$300 per tonne were the scenarios sharply restricted by the safety valve, and the third set of points with very high incremental costs are scenarios where corn ethanol was the marginal resource in the fuels market.

The graph shows that incremental costs of GHG reduction in the fuels market still remain greater in the fuels market as 98% of the scenarios lie above the line of equal costs (this percentage was 100% for the initial strategy). Finally, the incremental costs of GHG reduction still remain very high in the fuels market relative to other policies that limit GHG reductions. I've noted in earlier sections that this conclusion neglects the other benefits and is sensitive to the assumed costs of oil. Therefore, the result indicates that much higher oil prices and/or high valuations of the oil reduction benefits are required for this policy requirement in the fuels market to compete with other policies with the same objectives.

Figure 59 now compares all of the strategies on the percentages of low-cost and high-cost outcomes.

Figure 59: Percentage of Low-Cost and High-Cost Outcomes with All Strategies

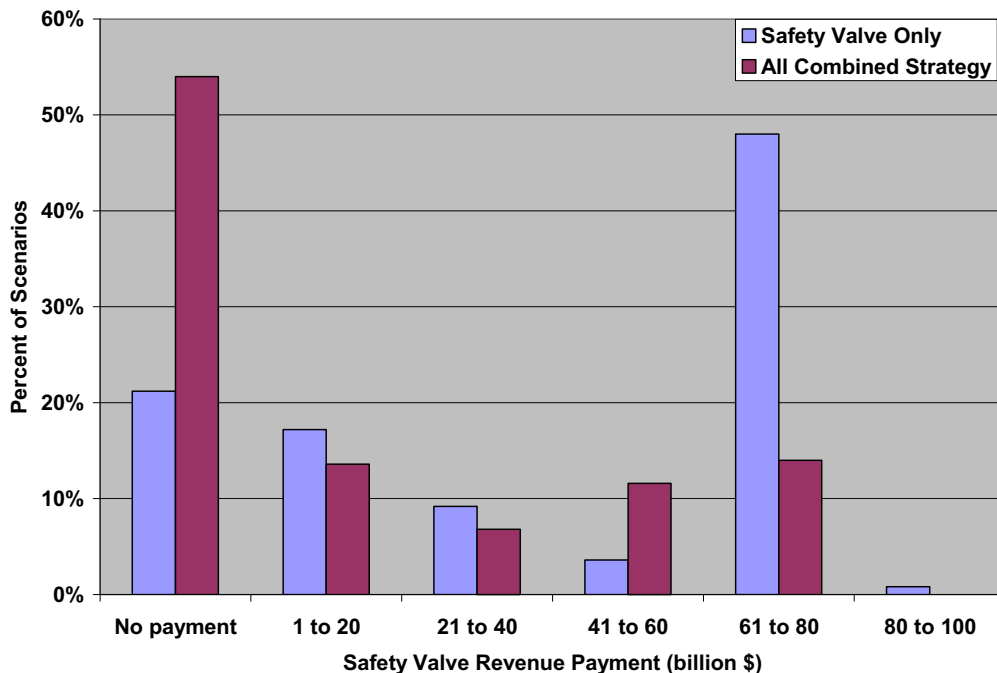


The first six columns compare strategies in the electricity market and the remaining columns display results for the fuels market. The figure shows the efficiency strategy had the largest effect on changing the percentage of low-cost and high-cost outcomes in the electricity market while the strategies including a safety valve were needed to contain costs in the fuels market. The all-combined strategy eliminates high-cost outcomes in nearly every scenario in both markets, except for 1% of the scenarios in the fuels market with average welfare losses slightly above the threshold. I noted earlier how the safety valve contains total incremental resource costs but that deadweight losses can push net welfare losses slightly above the threshold. The all-combined strategy achieves low-cost outcomes in 60%-70% of the scenarios in both markets.

The all-combined strategy limits costs within the desired ranges, but still requires trade-offs in reaching this outcome. Figures 55 and 56 showed the trade-offs in renewable energy development and greenhouse gas reductions. However, this strategy limited the magnitude of

the trade-offs relative to the individual strategies. Figure 60 shows the safety valve payments under the two strategies using this option.

Figure 60: Comparison of Payments under Strategies with Safety Valve



The graph compares the safety valve payments under the safety valve-only and all-combined strategies. The all-combined strategy considerably reduces payments made with a safety valve option; however, refiners and utilities still pay significant fees in over 10% of the scenarios. The all-combined strategy also considerably raised the percentage of scenarios with no payments by more than double to over 50%. While refiners and utilities still make large payments in scenarios where only limited renewable energy and efficiency is available below the safety valve price, the all-combined strategy considerably reduces the risks of this outcome relative to the safety valve-only strategy. I now further characterize three broad scenarios of future renewable energy costs that affect the outcome of the policy requirement and summarize how each strategy performs under these scenarios.

Three Broad Scenarios of Future Renewable Energy Costs Determine Policy Requirement's Outcome

The analysis in Chapters 3 and 4 shows the outcome of a 25% renewable energy requirement depends on progress in renewable energy technologies and their resulting costs in 2025 at the 25% level. In the later part of this chapter, I've described three broad scenarios for renewable energy technologies that characterize the range of outcomes under the policy requirement. Figure 61 illustrates these scenarios:

Figure 61: Conceptual Diagram of Three Renewable Energy Cost Scenarios Affecting Outcome of Policy Requirement

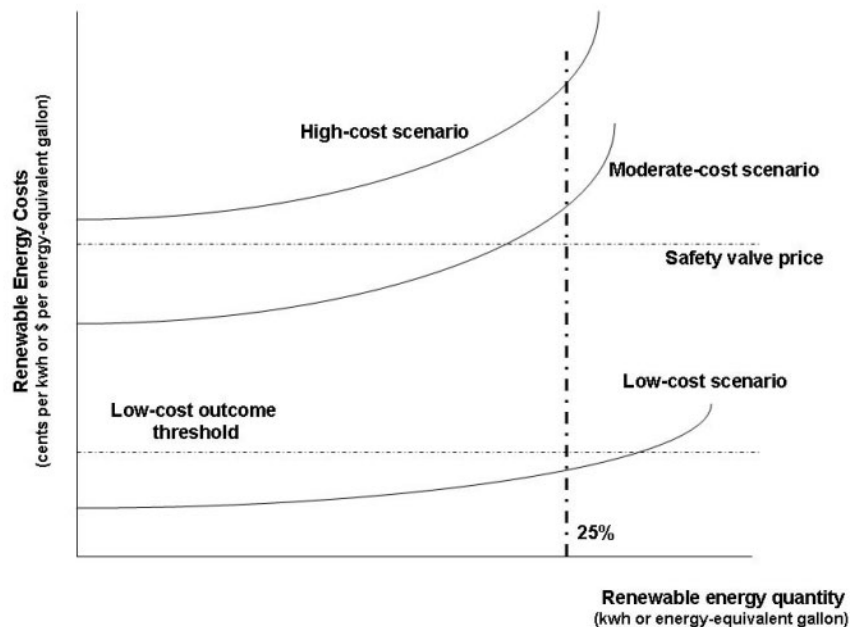


Figure 61 is a conceptual diagram of the key underlying scenarios affecting the outcome of the policy requirement under each strategy analyzed. The horizontal axis represents the quantity of renewable energy produced, and the vertical axis displays the cost of renewable energy. I've drawn in three dashed lines to illustrate key aspects of the policy requirement. The vertical dashed line indicates the quantity of renewable energy that meets the 25% requirement. The two horizontal dashed lines show the safety valve price and low-cost outcome threshold.

The three curves in the diagram are hypothetical renewable energy supply curves that illustrate the three broad renewable energy cost scenarios that affect the outcome of the

requirement. In the low-cost scenario, renewable energy costs at the 25% level lie below the low-cost outcome threshold. Earlier results from the scenario discovery analysis in Chapter 3 showed these scenarios occur when wind power capacity can expand significantly with limited cost escalation, which primarily depends on progress in developing sites with marginal wind quality and containing the costs of linking remote sites to the transmission grid. The incremental costs of renewables substitution in all low-cost scenarios remained below 6 cents per kwh and in most scenarios these costs varied from 3.5 to 5 cents per kwh. In the fuels market, new biofuels technologies achieved significant technological progress and can convert biomass feedstock to liquid fuels at low cost. These outcomes generally occurred in scenarios with the costs of converting biomass feedstock into liquid fuels in the lower half of the assumed range (below \$98 per ton). Furthermore, large quantities of biomass feedstock are available at low cost. Under these conditions, both markets can increase renewable energy supplies to 25% at low cost.

The second curve in the diagram represents scenarios with more limited progress in these key technologies. Some renewable energy is available at costs below the safety valve price, but renewable energy costs begin to escalate quickly near the 25% target. In the example in the graph, renewable energy costs at the 25% level exceed the safety valve threshold and result in a high-cost outcome under the initial strategy. I will discuss how the other strategies can affect this outcome shortly.

The final curve in the diagram shows a high-cost scenario where the entire curve lies above the safety valve price and renewable energy costs at the 25% level rise far above the safety valve price. This broad scenario primarily applies to the fuels market and reflects situations where the actual costs of commercializing new biofuels technologies considerably surpass today's estimates, which are made while these technologies are still in a pre-commercial state and prone to underestimation. The illustrative scenario explains the range of very high-cost outcomes under the initial strategy that requires 25% renewable fuels in this market.

The outcome of a 25% renewable energy requirement depends on which scenario actually occurs in the future and the challenge decision makers face today in considering this policy is that the likelihood of each of these scenarios is deeply uncertain. I've shown in Chapter 3 that the initial strategy performs well under the low-cost scenario. Under these conditions, the policy requirement significantly reduces GHG emissions, lowers oil consumption, and vastly increases the renewable energy industry at low costs. However, this particular strategy performs

poorly under the two other scenarios. It still achieves large benefits but also incurs high costs, possibly very high in the fuels market.

In the analysis in this chapter, I've shown how the alternative strategies can potentially reduce the costs of the requirement while highlighting any trade-offs with the other policy objectives. The goal now is to identify which strategy is robust to the key underlying uncertainty about future renewable energy costs. As noted in Chapter 2, a robust strategy performs reasonably well across the range of uncertainties. I will argue that the all-combined strategy is the most robust to uncertainty in renewable energy costs but I first summarize how each of the alternative strategies performs across these three scenarios.

The five remaining strategies affect Figure 61 in two ways. The strategies including additional corn ethanol and energy efficiency increase the resources that can qualify towards the 25% requirement. These resources can decrease the costs of the policy requirement if some additional corn ethanol or energy efficiency is available at costs below the point where the renewable energy supply curve intersects the 25% under the initial strategy. If lower-cost resources are available, then these strategies lower and/or stretch the supply curve outwards. If no lower-cost resources are available, then these strategies have no effect relative to the initial strategy. The second way the alternative strategies affect the outcome is by capping the increasing cost of renewable energy at the safety valve level. With the strategies that include the safety valve, refiners and utilities will add renewable energy up to the point of the safety valve and then choose to pay the fee instead of producing more costly renewable energy.

The results earlier in this chapter showed that the unconstrained ethanol strategy reduced welfare losses primarily for the moderate- and high-cost scenarios depicted in Figure 61. In Figure 27, welfare losses declined most in the scenarios with the highest welfare losses under the initial strategy. Corn ethanol costs are also relatively high because corn is a relatively costly input to the process. Furthermore, corn prices can escalate rapidly with additional corn ethanol production. Overall, this scenario had limited effect on the low-cost scenarios and marginally reduced the policy's welfare losses in the moderate- and high-cost scenarios. The unconstrained corn ethanol strategy also came with trade-offs in somewhat lower, but still quite high, GHG reduction. The largest trade-off occurred in the sometimes significant rises in corn prices caused by increasing corn ethanol production.

The efficiency strategy reduced welfare losses, sometimes considerably, in all three renewable energy cost scenarios. The results showed that this strategy was particularly effective at reducing welfare losses in the moderate-cost scenarios, and indicate that substituting about

5%-10% of efficiency for renewable energy was enough to stretch the supply curve to prevent it from reaching the portion with rapidly escalating costs at the 25% level. Figure 38 best showed this effect where the percentage of low-cost outcomes in the electricity market increased from 19% to 59%. This strategy did require trade-offs with the amount of renewable energy produced and GHG reductions. However, renewable energy use remained above 20% for most results under this strategy and rarely dropped below 15%. Under all of the efficiency strategy results, the renewable energy market would still expand substantially from the assumed baseline level. Finally, the efficiency strategy could not always prevent high-cost outcomes under the scenario with highest renewable energy costs. Energy efficiency costs are also uncertain and an additional 5%-10% of energy efficiency may have little effect when energy efficiency is also costly. Based on the results shown in this chapter, the efficiency strategy can effectively lower welfare costs in the moderate-cost strategy but requires a trade-off with renewable energy development, lowering GHG emissions, and reducing oil consumption. However, Figures 36 and 39 suggest these trade-offs are modest. The primary weakness is the strategy can still result in costly outcomes under the high-cost scenario for renewable energy costs.

The joint strategy combines the unconstrained ethanol and efficiency strategies, and the results indicate that it retains most of the cost-savings benefits of the efficiency strategy in the moderate-cost scenario while moderating some of the trade-offs with renewable energy production. In the joint strategy, corn ethanol displaces some of the energy efficiency and results in more renewable energy production. The addition of energy efficiency also mitigates some of the sharp increases in corn prices by reducing the amount of corn ethanol produced relative to the unconstrained ethanol strategy. The primary weakness of the individual strategies still remains with the joint strategy. This strategy was also susceptible to costly outcomes under the high-cost scenario for renewable energy costs.

The safety valve-only strategy effectively limited costs of the policy requirement with the moderate- and high-cost scenarios. However, Figure 51 showed that it constrained any new renewable energy development under the high-cost scenario and resulted in substantial safety valve payments in excess of \$60 billion. These large payments occurred in almost half the scenarios in the sample. This strategy had small effect on the results under the low-cost scenario.

All-Combined Strategy Balances Objectives and Most Robust to Uncertainties in Technology Costs

In the preceding discussion, I've summarized how the first five strategies performed under the three key scenarios for renewable energy costs. I've showed that each of these strategies has at least one weakness. The all-combined strategy improves on these strategies by including additional resources that qualify towards the requirement, and the results have shown that adding these resources has considerable potential to reduce welfare costs in the moderate-cost scenario. The all-combined strategy also uses a safety valve to contain the costs of the moderate- and high-cost scenarios when additional corn ethanol and efficiency are not sufficient to limit costs.

By combining the two key elements of the previous strategies, additional qualifying resources and a safety valve, the all-combined strategy is the most robust to the uncertainty in future renewable energy costs at the 25% level. Under the low-cost scenario, the all-combined strategy performs nearly identical to the initial strategy. With this scenario, renewable energy is generally the lowest-cost resource and will satisfy all or nearly all requirement. Some energy efficiency may substitute for renewable energy, but because renewable energy costs rise only slightly in the supply curves represented by this scenario the magnitude of substitution is small. With the moderate-cost scenario, the all-combined strategy can reduce welfare costs by adding lower-cost corn ethanol and energy efficiency to the supply curve. It also contains costs with the safety valve if only a limited amount of these resources are cost-competitive. The combination of all of these elements also moderates the trade-offs with renewable energy use, GHG reductions, and rising corn prices. Finally, with the high-cost scenario, the all-combined strategy limits welfare losses considerably relative to the strategies that do not include a safety valve and also improves on the safety valve-only strategy. The safety valve-only strategy excluded the additional resources that could qualify towards the requirement and resulted in a large number of scenarios with very high payments over \$60 billion (almost half the scenarios). The all-combined strategy reduces potential safety valve payments by adding corn ethanol and efficiency when they are cost-competitive. With the addition of these resources, Figure 60 showed the all-combined strategy significantly lowered the percentage of scenarios with payments over \$60 billion to 14%.

The final advantage of the combined strategy is that it provides certainty for the key groups affected by the policy requirement. Consumers have certainty that costs will not rise above the level set by the safety valve. Refiners and utilities also have certainty about the

policy's costs because of the safety valve. Renewable energy producers and investors have certainty that the market for this energy will expand and the safety valve sets a target price they must beat to sell their energy supplies.

The combined strategy does create greater regulatory burdens to administer the policy in comparison to the initial strategy. The government would have to set rules on the efficiency technologies available under the policy and the savings associated with each technology. Ideally, the agency administering the policy would verify these savings and adjust the rules if necessary. The government would also have to establish a trading market, which many RPS policies already have, and set the safety valve threshold. These are additional administrative costs of the policy that decision makers need to weigh against the risks of high-cost outcomes under a simplified policy like the initial strategy. A second issue is that combined strategy is potentially easier for opponents to undermine through the regulatory process. This is a possibility; however, the initial strategy is also vulnerable to this change. Future policy makers can always revise the policy requirement. Moreover, the initial strategy is possibility more vulnerable if it results in high-cost outcomes that could have been avoided under the combined strategy.

The analysis in Chapters 3 and 4 showed that considerable transfers occur under all of the strategies (although generally lower with the policies including efficiency) and indicate significant political capital is needed to pass and sustain any policy requirement that will affect energy markets to this degree. The all-combined strategy is potentially easier to sustain because it mitigates the more extreme surplus transfers in the fossil fuel and corn markets.

CHAPTER 5: CONCLUSIONS

Policy makers at the federal and state levels of government are currently debating many policy proposals to curb growing greenhouse gas emissions and reduce the nation's high reliance on oil as an energy source. Chapter 1 discussed societal concerns about growing greenhouse gas emissions and oil dependence and noted several externalities that suggest a role for public policy in addressing these issues. Many economists and policy analysts argue that market-based policies that directly address the externalities, such as an oil tax or broad-based cap-and-trade market for greenhouse gas emissions, are the least-cost policies to address these issues. However, in this country policy makers have avoided market-based policies, so far, and renewable energy requirements have emerged as one of the primary policies to reduce GHG emissions, lower oil consumption, and stimulate renewable energy technologies. Congress and 27 states have passed these requirements in various forms in both the electricity and motor vehicle transportation fuels markets. Furthermore, California recently proposed to use higher renewable energy requirements in both markets as a key strategy in meeting the greenhouse gas reduction targets passed in 2006. In Senator Obama's "New Energy for America" plan, he proposes a 25% renewable electricity requirement by 2025 and decreasing the carbon intensity of motor fuels 10% by 2020. These proposals indicate that policy makers' interest in renewable energy requirement remains high.

Despite this considerable interest in renewable energy requirements, only a limited number of studies have analyzed national-level renewable energy requirements, and Table 2 (in Chapter 1) summarized these studies. Three previous studies assessed a 25 x 25 policy (English et al., 2006; EIA, 2007c; Toman et al., 2008) and this dissertation advances the literature by assessing the social welfare implications of the policy requirement as well as the surplus transfers between key interest groups, applying new methods of uncertainty analysis in energy-economic modeling, and analyzing policy options decision makers can use to mitigate against the uncertainties in energy markets.

Based on the extensive analysis of the 25x25 policy shown in Chapters 3 and 4, this dissertation shows:

- 25% requirement without any contingent policies (initial strategy) is vulnerable to costly outcomes;

- 25% requirement reduces greenhouse gas emissions significantly in nearly all scenarios;
- meeting 25% requirement is likely to require substantial political capital;
- alternative strategies can reduce welfare losses but require trade-offs with other policy objectives and potentially increase welfare losses in other sectors;
- a safety valve-only strategy can limit direct consumer costs but producers may pay costly fees; and
- the all-combined strategy balances competing objectives and most robust to uncertainties in future renewable energy costs.

25% Requirement without Contingencies is Vulnerable to Costly Outcomes

Chapter 3 showed that the 25% requirement implemented under the initial strategy resulted in a wide range of outcomes. The range of results included many low-cost scenarios in both markets but nearly one-third of the scenarios in the fuels sector resulted in costly outcomes that large numbers of consumers are likely to oppose. After analysis on the factors associated with the low-cost outcomes, I found that wind power technology needs progress in utilizing marginal wind power sites to achieve 25% renewable energy at low cost. In the fuels market, I found that biofuels conversion technologies and biomass feedstock cultivation need very significant progress to produce 25% renewable energy in the fuels market at low cost.

The scenario discovery analysis also showed that even with progress in renewable fuels technology that the requirement can cause high-cost outcomes; similar results also apply to the electricity market. The policy requirement causes high-cost outcomes in the electricity market when developing marginal wind sites exceeds EIA's current cost estimates and rising feedstock prices raise biomass power costs over competing renewable electricity technologies. The policy can cause this outcome even with some progress in wind turbine technology (reducing capital costs) when high costs of developing lower-quality sites more than offsets cost reductions from technological improvements in wind turbines. Reaching 25% renewable energy would increase the cumulative capacity of wind power far beyond current levels, and even though wind is a relatively established technology, producing the amount anticipated in a 25% requirement still entails significant uncertainties.

The analysis shows that the initial strategy is vulnerable to costly outcomes because only a limited number of technologies can significantly increase their capacity given current technology. Wind power and biomass are the lowest-cost renewable energy technologies with considerable capacity to produce renewable electricity. Because the requirement in the fuels

sector compels a large demand for biomass to produce liquid fuels, the outcome in the electricity market depends largely on the costs of wind power at high capacity.

In the fuels sector, cellulosic ethanol and biomass-to-liquids supply most of the biofuels to meet the requirement. The capacity for corn ethanol and ethanol imports are limited in the initial strategy, which follows EIA's AEO 2006 assumptions. Furthermore, biodiesel produced from soybean oil is also limited because of the relatively low yield of biodiesel from soybean oil. Because of these constraints in this strategy, cellulosic ethanol and biomass-to-liquids comprise the majority of biofuels produced to meet the requirement and the outcome depends on progress in technologies used to convert biomass feedstock into liquid fuels as well as growing and supplying biomass feedstock to the refineries.

25% Requirement Reduces Greenhouse Gas Emissions Significantly Under Broad Range of Uncertainties

Figure 16 showed the initial strategy reduced GHG emissions by at least 20% of the total projected 2025 emissions from the electricity and transportation sectors in nearly every scenario, and emissions decreased by over 25% in many scenarios. The policy requirement only included a subset of the total transportation sector (airplane, marine, and train transport excluded); therefore, these reductions are considerably larger decreases in emissions from the sectors included in the analysis. EIA does not disaggregate its emissions projections within sectors so the total sector emissions were the only estimate available for comparison.

The alternative strategies discussed in Chapter 4 lowered the welfare losses but they also decreased GHG emissions reductions. GHG emissions reductions declined because the alternative strategies lessened the conservation effects of the policy requirement—reductions caused by decreases in energy consumption—as these strategies lower energy prices relative to the initial strategy. While the alternative strategies decreased the overall reductions, the reductions were still significant in most cases. Even with the lowest reductions in the safety valve-only strategy (approximately 600 million tonnes), the GHG emissions decline by nearly 15% from the total projected emissions from electricity and transportation in 2025.

The assumptions in the analysis about baseline energy production and carbon intensities can affect the results on GHG reductions. This analysis uses the AEO 2006 projection as the baseline, which projects the current mix of energy sources remains relatively similar with some increase in coal use in the electricity sector. EIA projects this result because it assumed no climate policy in their reference case (the EIA only analyzes trends based on current policy) and

fossil fuels cost less than most renewable energy sources. If the baseline shifted considerably from the AEO 2006 projection and the energy mix had a lower carbon intensity, perhaps with a greater share of natural gas, nuclear power, and renewables in the baseline, then the 25 x 25 policy would result in lower greenhouse gas reductions. Of note, even as the EIA has revised their assumptions about energy prices in the subsequent editions of the AEO, coal remains a dominant fuel in their projections for the electricity sector and the mix of fuels has not changed significantly but the overall level of consumption declined as energy prices rise.

A second key assumption is the carbon intensity of renewable energy. I've used the best estimates in the literature available at the time I developed the model. For many of the technologies, the carbon reduction potential has considerable uncertainty because of variation in production processes, especially biomass-based sources. Achieving large greenhouse gas reductions from biofuels may require some regulation on which production processes qualify towards the requirement. The EU is currently confronting this issue in rulemaking for a directive requiring 10% biofuels by 2020 and is developing a set of standards for biofuels (Eickhout et al., 2008). U.S. policy makers may want to consider similar standards in implementing a policy requirement to ensure biofuels development reduces GHG emissions without serious unintended consequences to other environmental concerns, such as maintaining water supplies, water quality, and biodiversity.

25% Requirement Likely to Require Substantial Political Capital

The results shown on the surplus transfers between energy consumers, fossil fuel producers, and biomass producers illustrate that energy consumers and fossil fuel producers can transfer potentially considerable amounts of surplus to other groups under the policy requirement. Electricity and motor vehicle fuels consumers lose surplus as energy prices rise and they transfer this surplus to renewable energy and biomass producers. More broadly, energy consumers do gain some surplus in the markets for fossil fuels, because the renewable energy requirement decreases the prices of oil, natural gas, and coal. The decline in these prices decreases fossil fuel producer surplus earned on the remaining energy consumption. The main beneficiaries are oil and natural gas consumers outside of the electric power and transportation fuels markets as the higher costs for renewables offset fossil fuel price declines in electricity and transportation fuels.

The welfare analysis on the costs of the 25% requirement does not include these costs because they are a transfer between economic agents, except for oil imports. However, these

considerable transfers between groups within society indicate the policy will require significant political capital to pass and sustain. Fossil fuel producers could lose considerably with this policy. They are a highly organized political constituency and will lobby vigorously to oppose the policy requirement or diminish its impact if it becomes policy. Energy consumers are a more diffuse constituency but, as recent increases in energy prices show, potentially very effective if broad-based opposition develops within the voting public.

Chapter 4 also showed the surplus transfers from corn consumers to corn producers in the strategies that include increased corn ethanol production. The results show that the requirement could also transfer substantial surplus from corn consumers to producers. These transfers would occur through higher prices for corn, food products, and livestock fed by corn products. Furthermore, the transfers in the corn market would occur in addition to any surplus transfers from higher energy prices. The combined surplus transfers from higher energy and food prices may generate widespread consumer dissatisfaction with the policy requirement if the magnitudes become considerable. Finally, the results for the joint strategy shown in Chapter 4 indicate that allowing unconstrained corn ethanol and efficiency decreases corn ethanol production relative to the unconstrained ethanol strategy, which moderates surplus transfers in the corn market.

Alternative Strategies can Reduce Welfare Losses but Trade-off with other Policy Objectives

The results in Chapter 4 show that the alternative strategies can decrease welfare losses in many scenarios, often substantially. In every case though, the lower welfare losses come with a trade-off in another policy objective and possibly increase welfare losses in the other market. With the unconstrained ethanol strategy, increasing corn ethanol production displaced higher-cost biofuels in many scenarios but often increased welfare losses in the electricity sector. Corn ethanol production is natural gas intensive and this new demand for natural gas decreases the net effect of natural gas demand displaced by renewable electricity. Increasing corn ethanol production also raises corn prices and transfers surplus from corn consumers to corn producers. Finally, displacing higher-cost biofuels with corn ethanol production may lower the GHG emission reductions because corn ethanol is relatively more carbon intensive in comparison to other biofuels considered in this study.

The analysis on the efficiency strategy showed that substituting energy efficiency for renewables can significantly reduce the costs of the policy requirement in most but not all scenarios. Energy efficiency had the largest overall impact on the electricity sector as this

resource cost-effectively displaced renewables across a wide range of the scenarios and considerably increased the percentage of low-cost outcomes. While adding efficiency reduced costs across a broad range of scenarios in the electricity market, efficiency in the fuels market resulted in the largest welfare loss reductions in scenarios where low-cost efficiency improvements could displace very costly biofuels. The results also showed interaction effects between the markets. When efficiency reduces total biomass demand, it decreases feedstock costs in both markets. Therefore, it does not need to directly displace renewables in both markets to yield savings across both sectors. This particular result suggests that a targeted efficiency program can realize many benefits in both markets without displacing considerable amounts of the renewable energy. Finally, the results showed a trade-off with GHG emissions and renewable energy development when substituting efficiency for renewables. Adding efficiency decreased GHG emissions reductions because the conservation effects from higher energy prices declined under the efficiency strategy. Another trade-off is that adding efficiency to directly offset renewables diminishes investment in renewable energy technologies and the development in this sector. However, Figure 39 shows that in the majority of scenarios efficiency does not substitute for considerable amounts renewable energy use. In the electricity market, adding efficiency up to about 5% of requirement realizes a large portion of the savings potential. Efficiency displaced relatively more renewable energy in the fuels market; however, renewable energy still remained above 15%, which is a large increase from the projected baseline of 3% renewable fuels in 2025.

The joint strategy retains most of the cost savings from efficiency strategy and increases renewable energy production in many scenarios when additional corn ethanol production cost-effectively displaces higher-cost biofuels. Figure 45 showed that corn ethanol production increased near 10 billion gallons in numerous scenarios under this strategy (in addition to the baseline of 12 billion gallons). Allowing efficiency with higher corn ethanol production mitigated some of the worst effects of the unconstrained ethanol strategy on higher corn prices and surplus transfers from corn consumers to producers. However, the joint strategy did increase electricity market costs modestly relative to the efficiency strategy (because of higher natural gas demand) in many scenarios.

Overall, the alternative strategies adding corn ethanol and energy efficiency can reduce welfare losses and mitigate some of the trade-offs with other policy objectives seen in the individual strategies. These policies can reduce costs without serious effects on other policy objectives when renewable energy costs are in the middle range of costs. When renewable

energy costs are in this moderate range, increasing efficiency and corn ethanol can displace the highest cost renewables, which can often yield significant savings because the supply curves are increasing, non-linear functions. However, when renewable energy costs are in the upper range of costs, potentially large amounts of efficiency and corn ethanol are cost effective but they begin to pose problems as trade-offs with the other objectives increase. When renewable energy costs reach these higher levels, the safety valve policy can more effectively limit costs.

Safety Valve-Only Strategy can Limit Welfare Losses but Refiners May Pay Considerable Fees

The results for the safety valve-only strategy show it effectively limits the risks of high welfare losses but it constrained any new renewable energy production in scenarios where new biofuels costs exceed the safety valve price. Figure 47 shows that the welfare losses in both markets decline considerably with the safety valve. The maximum welfare loss declines by about 50% in the fuels market and the decrease in the electricity market is just over 30%. Moreover, Figure 48 illustrates that the safety valve limits the policy's costs below the high-cost outcome threshold in every scenario.

While the results show the safety valve can contain welfare losses, it also forces producers to pay significant sums in permit fees in many scenarios. In nearly half the scenarios, the safety valve-only strategy required producers to pay more than \$60 billion a year. Liquid fuel producers pay nearly all of these fees as the safety valve-only strategy primarily affects the fuels market. Producers pass on these costs in higher energy prices as prices rise enough to pay the revenue owed to the government; however, the direct price increase is relatively small because the total payments are spread over the entire amount of energy consumption. For this reason, consumers only indirectly pay these fees. Producers, on the other hand, pay the permit fees directly and are likely to organize opposition to the policy if the payments under the safety valve become exorbitant.

Combined Strategy Balances Competing Objectives and Most Robust to Uncertainties in Future Renewable Energy Costs

One of the fundamental challenges of the renewable energy requirement is that the outcome depends heavily on the future progress of renewable energy technologies, more specifically the costs of renewable energy at the 25% level in 2025, and these costs are highly uncertain today. Innovation in renewable energy technologies will reduce costs; however,

reaching 25% renewable energy in both markets will require using much lower-quality sites for wind power, biomass production, and other site-specific resources like geothermal power. Costs increase at lower-quality sites and the balance of these uncertain effects will determine the future costs of these technologies. A third factor is that some technologies that could play a large role in reaching 25% are currently in a pre-commercial state and the eventual costs of these technologies at a commercial scale are large uncertainties. Cellulosic ethanol and biomass-to-liquids technologies are prime examples.

In the final section of Chapter 4, I describe three broad scenarios in future renewable energy costs that affect the outcome of the policy requirement. In the first scenario, technological progress in renewable energy significantly reduces their costs and renewable energy can provide 25% of energy demand in both markets within the low-cost threshold identified in Chapter 3. Under this future scenario, the initial strategy reaches 25% renewable energy at low-cost, but the other strategies would also achieve this outcome because renewables are always the low-cost resource.

In the second broad scenario, more limited progress in renewable energy technologies leads to higher costs at the 25% level. Under this scenario, the initial strategy produces a large number of medium-cost and high-cost outcomes. The results show that higher corn ethanol production can lower the percentage of high-cost outcomes marginally but the efficiency strategy considerably reduced costs in both markets resulting in a large increase in the percentage of low-cost and high-cost outcomes. However, some high-cost outcomes still remained with the efficiency-only strategy. The safety valve-only strategy limited the percentage of high-cost outcomes but did not have the advantage of the efficiency strategy which lowers costs in any scenarios when energy savings cost less than renewables. The all-combined strategy has the advantage of adding corn ethanol production and efficiency when these technologies are cost-competitive while also constraining the high-cost outcomes. In this middle scenario for renewable energy costs, the safety valve option does not require the substantial payments.

In the third broad scenario, which primarily applies to the fuels market, only a limited amount of new renewable energy is available at costs below the safety valve price. Under the initial strategy, this strategy generated the highest welfare losses. The strategies with unconstrained corn ethanol and efficiency were also not very effective because these resources also entailed high costs or did not have sufficient low-cost resources to displace very costly biofuels. The safety valve-only strategy imposed a severe constraint in the fuels market and resulted in very high payments by refiners. The all-combined strategy marginally improved on

the others by allowing the additional corn ethanol, which increased by about 3 billion gallons in most scenarios, and energy efficiency before the safety valve limited the market. The all-combined strategy still resulted in large payments where over 10% of the scenarios required payments over \$60 billion.

In comparing across these three broad scenarios, the all-combined strategy is the most robust. It does no worse than the other strategies in the first scenario with low renewable energy costs and the final case with very high renewable energy costs. The all-combined strategy performs best in the middle case because it allows additional corn ethanol and efficiency to displace higher-cost biofuels from cellulosic ethanol and biomass-to-liquids while also containing the high-cost outcomes where less costly corn ethanol and efficiency were not available. This strategy does trade-off some renewable energy production with its associated benefits to limit the risks of high costs. However, in the middle scenario for renewable energy costs, this trade-off is not severe and the results showed that efficiency typically substituted for about 5%-10% of renewable energy. Even in these scenarios with 5% -10% efficiency, renewable energy use increases substantially from the baseline levels.

In conclusion, this dissertation showed a wide range of potential outcomes for a 25 x 25 policy requirement because of the deep uncertainty in renewable energy costs at this level of penetration. To achieve 25% renewable energy in the electricity and fuels markets, several current technologies will need to expand capacity far beyond current use and the costs of these technologies at high levels of use remain highly uncertain. In addition, several technologies that are not currently produced at a commercial scale will need to reach a commercial state and significantly expand production. The costs of these technologies in 2025 at high capacity are even greater uncertainties. This dissertation analyzed six strategies for implementing a 25 x 25 renewable energy requirement. These strategies varied in the level of new corn ethanol production and energy efficiency qualifying towards the policy requirement as well as including a safety valve option that contains the costs of the policy. The analysis showed that the strategy including all of these options for implementing the policy was the most robust to future uncertainty in renewable energy costs.

This dissertation applies new methods in uncertainty analysis to a current energy policy proposal. The models used in the analysis had limited ability to explore uncertainty in future fossil fuel costs. Furthermore, the baseline values assume no change from current energy policy. Applying these analytical methods to energy-economic models that can vary these uncertainties

remains an area for very promising future research. Current energy policy proposals in Congress and many states are combining market-based instruments to limit GHG emissions, such as a cap-and-trade system, with additional requirements on renewable energy and energy efficiency. Policy analyses on these hybrid instruments that address future uncertainty in energy markets will be highly valuable to decision makers as they consider these policies.

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TECHNICAL APPENDIX

BASELINE DATA AND NUMERICAL PARAMETER ASSUMPTIONS

This appendix details the numerical assumptions and baseline figures going into the simulation models. It first summarizes the baseline information from the AEO 2006, and then discusses the assumptions used for the electricity and motor fuel markets. Each of these sections contains description of the renewable energy technologies, energy efficiency technologies, and assumptions used in modeling the primary fossil fuel energy markets (oil, coal, and natural gas). The appendix also shows the methods and data used to estimate the outcome measures in the study, ranges and descriptions of key parameters used in the uncertainty analysis, and calculations used to define low-cost and high-cost outcomes.

BASELINE FIGURES FOR USE IN MODEL BENCHMARKING

As noted, the analysis uses the 2006 AEO reference case scenario for 2025 to benchmark the calculations. **Table A.1** summarizes some key, basic features of this scenario relative to actual figures for 2004, while **Figure A.1** shows the assumed price path for crude oil in this EIA scenario. For completeness, it also shows comparable information from the EIA high-oil price scenario.

Table A.1

EIA 2006 Annual Energy Outlook Projections and 2004 Observed Data

Projection	2004	AEO Scenario for 2025	
		Reference Case	High Oil Price
GDP (billions of 2000 chain-weighted dollars)	10,756	20,123	20,100
Electricity production (billions of kwh)	3,612	4,945	4,944
Coal	1,916	2,728	3,084
Natural gas	486	775	411
Nuclear	789	871	871
Hydroelectric	265	299	299
Other renewable	54	187	201
Average household price for electricity (2004 cents/kwh)	8.9	8.4	8.6
Motor fuel use			
Gasoline and diesel (millions barrels per day of oil equivalent)	11.07	15.23	13.84
Unconventional	0.00	0.58	1.00
Average wholesale price of motor fuels (2004 \$/gallon)	1.22	1.53	2.41

Source: EIA (2006a).

Figure A.1

EIA AEO 2006 Crude Oil Price Projections

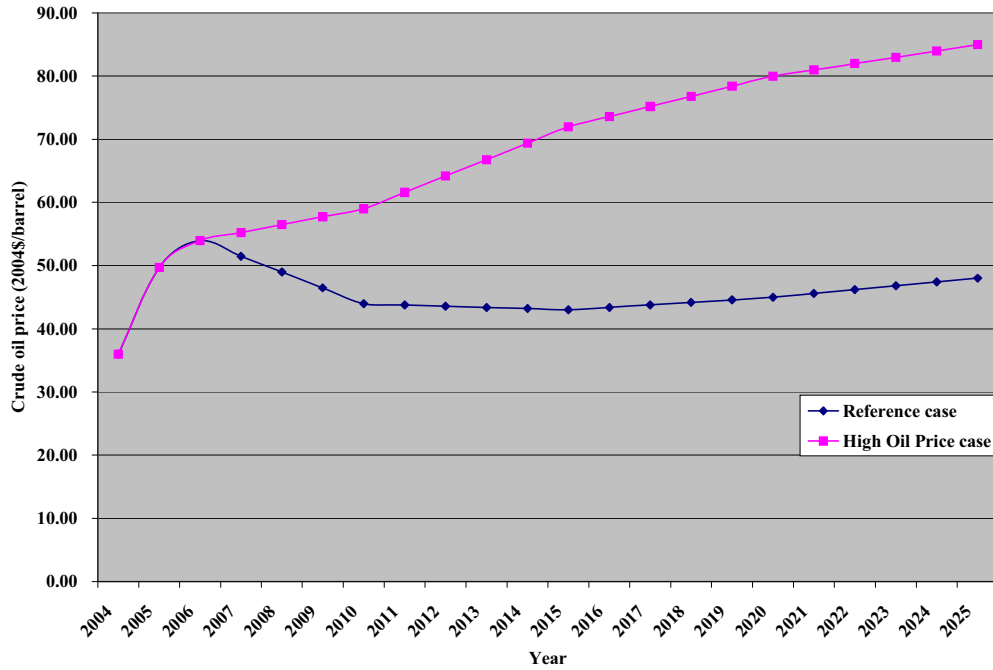


Figure A.1 shows that, in EIA's reference case, crude oil prices decline to about \$45 per barrel followed by an increase in the latter part of the projection period. Crude oil prices steadily increase in the high-oil price case and exceed \$80 per barrel in 2025. EIA has revised these projections upward in the 2007 and 2008 AEOs. However, crude oil prices in the reference case projections follow the same general trend: Prices decline from current levels in the initial period, followed by a steady increase in the latter portion of the projection period.

One other important piece of baseline information for the analysis is the expected amount of new capacity that will be built between 2010 and 2025 and for which planning has not started.

Table A.2

2006 AEO Projections for New Electricity Capacity Added from 2010 to 2025

Type	Coal	Natural Gas Combined Cycle	Combustion Turbine	Nuclear	Wind	Biomass	Other Renewable
Amount (GW)	74.4	41.9	26.6	6.0	3.53	1.45	4.14

Source: EIA (2006a, tables A.9 and A.16).

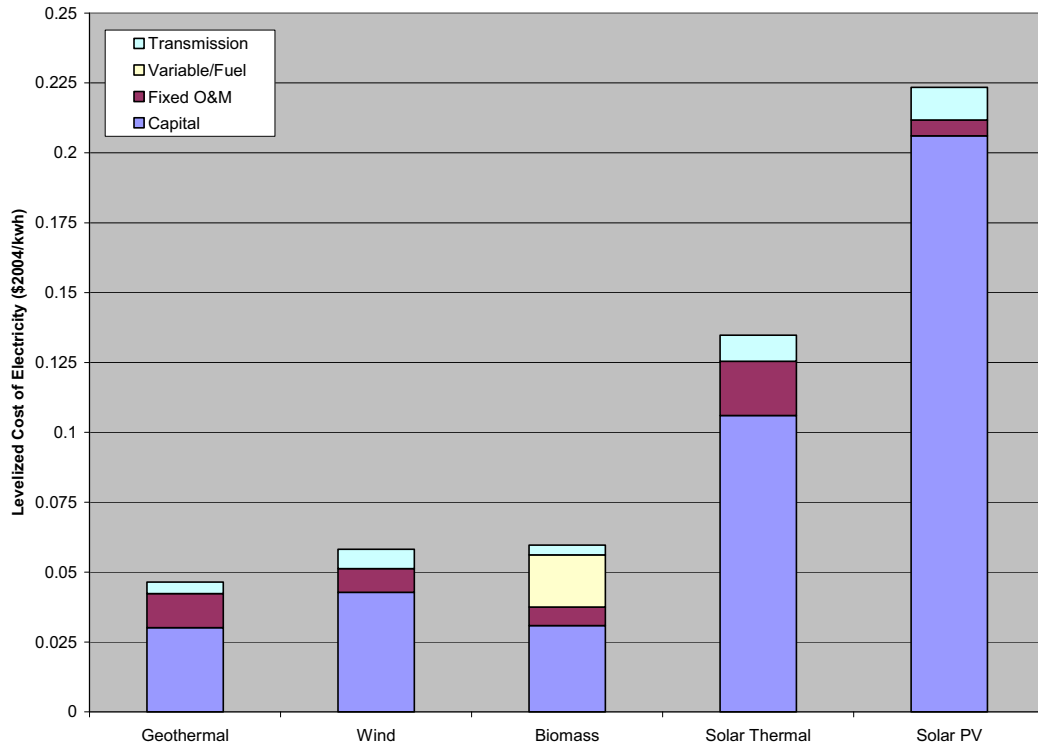
As shown in Table A.2, for the reference case of its 2006 AEO, EIA projected 148.9 GW of new fossil fuel and nuclear power capacity to be built between 2010 and 2025. This includes capacity built to replace current capacity likely to be retired during this period, as well as capacity built to meet increasing demand for power. I use 2010 capacity plus any currently planned capacity as the baseline for assessing how a 25x25 policy could cause future capacity substitution. I assume that this baseline of built and planned capacity in 2010 is unlikely to be affected by a 25x25 policy requirement. Renewable electricity could substitute for new capacity scheduled to come online after 2010 if that prospective policy requirement were imposed soon.

ASSUMPTIONS ABOUT RENEWABLE ELECTRICITY COSTS

In evaluating the options for substituting successive amounts of renewable for nonrenewable capacity in 2025, we rely initially on EIA estimates for the LCOE. These costs are the average costs associated with the various technology alternatives at the level of power generation specified for each in the 2006 AEO reference case.

Figure A.2

AEO 2006 Renewable Electricity Cost Projections for 2020



SOURCES: EIA (2006a) reference case cost assumptions; Beamon (2007a).

I use 2020 costs as opposed to 2025 because most power plants will need to be already constructed or under construction by this point to meet the 2025 target. EIA's cost projections actually have minimal cost change between 2020 and 2025 for geothermal, wind, and biomass. They do show some progress for solar thermal and PV costs.

EIA's estimates of renewable technology costs give us a point of departure, or a benchmark, for developing alternative supply curves for the technologies. EIA uses expert judgment in assessing future technology costs. But it is widely recognized that there are uncertainties about these future costs. Renewable technology performance and competitiveness may progress significantly or more slowly. To take into account this uncertainty, I allow each technology's benchmark levelized cost to vary within a range, as discussed in a following section on uncertainty analysis.

The marginal costs of most renewable technologies can be expected to increase as generating capacity expands, because renewable energy is a site-specific resource and costs rise as higher-quality sites are developed, leaving lower-quality sites for the next increments of capacity. I address this in the construction of marginal costs by treating the benchmark figures discussed earlier as the marginal cost of the first increment of added supply (i.e., the vertical intercept of the marginal cost curve). How rapidly costs will rise from this level will depend on several uncertain factors, among them the potential for unit cost savings as output expands due to economies of scale and learning by doing. I describe next how I accounted for these various factors in developing cost curves for each renewable technology.

Wind

Potential wind farm sites vary in several factors that affect their development costs, such as average wind speeds and distance from transmission lines. EIA uses a coarse, aggregate set of cost escalation factors to reflect how development costs increase at lower-quality sites. The escalation factors classify potential regions into several cost levels, account for differences in wind quality, distance from transmission lines, and site-development costs. Their capacity data are based on geographic information system (GIS) analysis of average wind speeds throughout the United States and applying filters to exclude areas that are too far from existing transmission lines, too mountainous to develop a site, and lands on which wind power development is an incompatible land use, such as military bases and national parks (EIA, 2006a). **Table A.3** shows this information: escalation factor at different steps in the cost curve and the corresponding LCOE based on EIA's baseline cost.

Table A.3

Wind Supply Curve Data

Cost Escalation (%)	LCOE (2004 dollars per mwh)	Capacity (GW)	Potential Generation (GW-hours [GWh])
0	58.2	27.7	91,237
20	69.8	40.5	133,397
50	87.2	80.6	265,477
100	116.3	87.7	288,863
200	174.5	2,223.2	7,322,687

Sources: Petersik (1999), Paul and Burtraw (2002).

The wind supply cost curves use capacity and cost assumptions from both EIA and Resources for the Future (RFF). EIA applies a set of cost multipliers to account for higher development costs of remote sites, poorer wind quality, costs of upgrading transmission lines, and increasing costs for competition over land. These multipliers increase wind costs by 20 percent, 50 percent, 100 percent, and 200 percent over the initial baseline cost. The capacity estimates were developed for EIA and are used in the NEMS model; they are also used in RFF's Haiku model (Petersik, 1999; Paul and Burtraw, 2002). Table A.3 shows an enormous amount of potential wind capacity, but more than 90 percent is from lower-quality sites in the highest cost category. We use an average capacity factor¹ of 0.38 from the AEO 2006 to estimate the potential generation in each category.

For reference, the AEO 2006 projection for electricity consumption from electric utilities in 2025 is 4.9 million GWh (see Table A.1), and wind generation in the reference case is 63,000 GWh (slightly more than 1 percent of the total). Total potential generation in the first four cost levels is slightly more than 15 percent of total electricity demand. Therefore, significant expansion of wind power would require

¹ Capacity factor is the average amount of generation from a plant relative to its maximum potential output. The assumption of a constant capacity factor independent of location implies that wind quality is determined primarily by the average wind speed as opposed to wind duration.

developing the lowest-quality wind sites shown in Table A.3. Since current wind development remains well within the first cost step, the cost of developing the lower-quality sites is one of the highly uncertain parameters in the analysis. The construction costs and wind quality could be worse or better than expected, resulting in a higher or lower LCOE. The classification system used to estimate the site quality uses a coarse set of filters accounting for wind speeds, terrain, and distance to transmission lines. The analysis uses GIS software, and on-the-ground site inspection could find less favorable conditions. Conversely, new turbine technologies could improve wind capacity factors and the ability to develop low-quality sites. In the uncertainty analysis, I vary the cost escalation rates in Table A.3 by 50 percent.

Recent work at NREL to develop the Wind Deployment System Model (WinDS) to simulate high levels of wind power penetration shows much lower cost escalation factors as capacity increases. This analysis uses the base set of cost factors described earlier and varies the escalation factors through a considerable range. This approach captures the same range of potential costs implied by the more recent studies while also allowing for less favorable outcomes with much higher development costs.

Biomass

EIA assumes biomass electricity from IGCC power generating systems. I assume that plant capital and nonfeedstock operating costs do not change as additional generating capacity is built but that feedstock costs do increase as greater amounts are required. The details behind the construction of biomass supply curves are presented shortly in the section describing biofuels supply curves.

Cofiring and dedicated biomass-electricity plants will compete with other biomass energy sources for available feedstocks and bid up the price of biomass. Therefore, the ultimate use of biomass electricity depends on assumptions about feedstock supply costs, conversion efficiency, and demand for biofuels. The biofuel model also includes coproduction of electricity from biofuel plants.

Biomass cofiring also is constrained by the maximum amount of biomass that coal plants can mix into their fuel supplies and by the number of coal plants that could retrofit their plants. I assume that

existing coal plants can use biomass to produce up to 15 percent of their output. This follows the maximum constraint that EIA uses in the NEMS model. I also assume that, at a maximum, half of existing coal plants can use cofiring (Robinson, Rhodes, and Keith, 2003). With these constraints, assuming that sufficient biomass feedstock supply is available, biomass cofiring can substitute for up to 7.5 percent of coal-fired generation that would be in place in 2025.

Geothermal

I use a site-specific study of potential geothermal resources in the western United States conducted by the Sandia National Laboratories. In this study, Petty et al. (1992) estimated the costs of developing geothermal electricity from 43 potential sites in the western United States. I aggregated their site-specific data into cost curves. **Table A.4** shows the geothermal resource data.

Table A.4

Geothermal Supply Curve Data

Cost Level (2004 dollars per mwh)	Available Capacity (GW)	Potential Generation (GWh)
50	3.0	24,966
75	7.0	58,337
100	2.1	17,310
150	2.8	23,052
200	1.8	15,063
250	0.8	6,366
350	0.5	4,161

Source: Petty et al. (1992).

The analysis assumes a 0.95 capacity factor for geothermal generation, which is the estimate from the AEO 2006. EIA projects about 46,000 GWh of geothermal generation in the reference case for 2025, which uses most of the low-cost supply of geothermal resources. Additional generation from this source occurs at more-costly sites. I

allow variation in geothermal costs by compressing and expanding the cost curve increments by 25 percent. I use this level of variation in the cost escalation factors to account for the significant uncertainty in the costs of this resource.

Several recent analyses of geothermal resources show different projected available capacity and costs. These assessments include new technologies that would allow development of deeper sources of geothermal energy. A recent study by MIT assessed enhanced geothermal systems (EGS), which cover noncommercial technologies that mine heat sources at greater depths than do current geothermal projects. MIT's study concluded that a large potential exists for EGS (up to 100 GW). Under its base case assumptions, LCOEs from these projects can vary from about \$0.10 per kwh up to \$0.70 per kwh, depending on site-specific factors. Under a mature-technology case with technological improvement, EGS levelized costs can be competitive with fossil fuel sources (Tester et al., 2006).

Several factors limit the application of the MIT work to this analysis. MIT assumed a time horizon to 2050. Subsequently, EGS would need substantial R&D and technological improvement to provide significant amounts of economic capacity by 2025. Second, because EGS technologies are noncommercial by the definition used in the MIT report, the cost estimates are prone to underestimation (Merrow, Phillips, and Myers, 1981).

Two other recent analyses further illustrate uncertainties about geothermal capacity and costs. A study conducted for the Western Governors' Association (WGA) found that about 5.5 GW of capacity is available at a cost of less than \$0.08 per kwh and up to 12 GW at costs up to \$0.20 per kwh. The time frame for this analysis was 2015 and included only known geothermal sites. These estimates for capacity and costs are roughly comparable with Petty et al. (1992) after excluding existing capacity (WGA, 2006a). Finally, Petty and Porro (2007) recently published an updated assessment of geothermal supply potential for potential use in EIA's NEMS model. This assessment includes traditional hydrothermal vent technologies and newer technologies, such as EGS and coproduction of geothermal electricity at oil and gas fields. They

estimated more than 100 GW of potential capacity at costs of less than \$0.08 per kwh (Petty and Porro, 2007).

In this analysis, I use the capacity estimates from the original Petty et al. (1992) study excluding existing capacity. I then allow the range of cost-escalation steps to vary by 25 percent. This variation in cost steps accounts for the uncertainty in future development costs. The studies cited show potential for cost decreases in developing new sites with established technologies and using new technologies. I allow for higher potential costs to address greater-than-expected costs of developing marginal sites. Furthermore, I use the lesser capacity estimates from the Petty et al. (1992) and WGA (2006a, 2006b) reports to account for the fact that the 2025 time frame limits the ability of new geothermal technologies to become competitive with existing technologies.

Solar Thermal

I use a relatively small quantity of potential solar thermal capacity, which is assumed to be developed in the southwestern United States. For this resource, I assume that it can be developed at a uniform cost and then allow the magnitude of that cost to vary in the analysis. EIA's projection for solar thermal electricity provides the baseline cost, and allow it to vary within a range of -30 percent to +30 percent.

The estimates of solar thermal supply come from a recent analysis for WGA.² In 2004, WGA set a goal of increasing renewable energy capacity in the region by 30 GW by 2015. A solar task force comprised of experts in the region assessed the potential for solar thermal development in the region. In its analysis, it showed that substantial solar resource potential exists (upward of 200 GW) that is near existing power lines and population centers. However, the global solar power industry is constrained in production capacity. The WGA Solar Task Force analysis showed that, by 2015, the maximum production capacity is 13.4 GW (WGA, 2006b). Based on these supply constraints as assessed by solar

² See WGA (undated) for participating governors.

thermal proponents, we assumed a range of total capacity in the region by 2025 of 7-13 GW.

INCREMENTAL COST OF RENEWABLES SUBSTITUTION

The model calculates the cost of requiring additional renewable electricity in the electricity system by calculating the difference between marginal costs of renewable and nonrenewable resources. The analysis assumes that, under a national renewable requirement, new renewable capacity first will displace the new, projected fossil fuel and nuclear capacity. Therefore, part of the incremental cost of the policy is the difference between costs of the renewable capacity and projected nonrenewable capacity, namely the 149 GW shown in Table A.2. The incremental cost calculation differs for firm power resources, such as biomass and geothermal; a fossil fuel switching technology, such as biomass cofiring; and intermittent power resources, such as wind and solar. Table A.5 shows the assignment of different technologies to various categories based on their typical patterns of availability and use.

Table A.5

Electricity Power Plant Assignments

Technology Type	Plant Assignment
Base load	Pulverized coal
	Advanced coal (IGCC)
	Advanced combined cycle gas
	Conventional combined cycle gas
	Dedicated biomass
	Geothermal
	Nuclear
Peak load	Conventional combustion turbine
	Advanced combustion turbine
Intermittent	Wind
	Solar

I assigned power plant technologies to one of the three categories based on their operating characteristics and relative costs. Base-load technologies generally have low operating costs and high investment costs. The plant operator can vary their power output, but a fairly long time is required to attain large swings in power output. A base load-type plant is most efficiently and cost-effectively operated near its maximum rated capacity for long periods. In contrast, peak-load technologies have higher operating costs but can be quickly dispatched to meet electricity demand during peak periods. Intermittent technologies produce electricity when the resource is available. Therefore, their output is variable and sometimes stored or supplemented by a peak-load technology that can balance the variable output.

Firm Power Technology

Firm power capacity can substitute for nonrenewable capacity on a one-for-one basis. Therefore, 1 Mw of biomass capacity would displace all the capital and fuel costs from a nonrenewable electricity source. The incremental cost then becomes the difference in the levelized costs of the renewable electricity source and the nonrenewable source that it

displaces. **Table A.6** shows the cost breakdown, using EIA's cost projections, for a biomass plant and several potential nonrenewable resources.

Table A.6

Cost Comparison for Firm Power

Cost	Power (2004 dollars per MWh)					
	Biomass	Advanced Nuclear	Conventional Combined Cycle	Advanced Combined Cycle	Advanced Coal	Pulverized Coal
Capital charge	30.86	42.23	11.65	11.08	29.9	25.97
Fixed operation and maintenance (O&M)	6.68	7.84	1.49	1.4	4.73	3.37
Variable or fuel ^a	18.69	6.72	41.38	38.61	14.85	18.74
Transmission	3.44	2.8	2.9	2.9	3.49	3.49
Levelized cost	59.66	59.59	57.43	53.99	52.97	51.56
Incremental cost of substituting biomass	0	0.07	2.23	5.67	6.69	8.1

^a Fuel costs are those assumed in EIA (2006a). In this model, biomass, coal, and natural gas costs are recalculated as the requirement for renewable energy increases.

The Capital charge through Transmission rows in Table A.6 show EIA's projected costs for each technology by type of cost. The Levelized cost row is the sum of these costs or LCOE for each technology. The Incremental cost of substituting biomass row shows the difference between the incremental cost of each technology and the renewable technology (biomass power). The model projects new fuel costs for biomass, coal, and natural gas as the policy requirement increases the amount of renewable energy in the system. In this process, biomass fuel costs increase as biofuel and electricity producers compete for the same feedstock and fossil fuel (coal and natural gas) prices change as demand for these fuels decrease. An important caveat for Table A.6 is that it

reflects baseline costs from EIA. As already noted, I address other possible baseline costs in the uncertainty analysis.

Fuel Switching Technology

The preceding section showed the incremental cost calculation for firm power technologies. The converse case is a pure fuel-switching (fossil fuel-saving) technology, such as biomass cofiring. With biomass cofiring, a coal-fired plant is retrofitted to feed a mixture of biomass and coal into the boiler. The renewable fuel does not offset capacity and displaces only the fuel used in the coal plant. The incremental cost of a fuel-saving technology is the levelized cost of the capital and fuel costs of cofiring minus the fuel cost in the coal plant. I use EIA's cost assumptions for retrofitting a coal plant of \$237 per kw of capacity (EIA, 2006a), and the fuel cost is determined endogenously by the model using the biofuel supply curves.

Intermittent Technology: A Hybrid of Firm Power and Fuel Switching

The incremental cost calculation for intermittent power sources is a combination of the firm power and fuel-saver calculations. I assume that wind and solar power are taken into the system as available and decrease the use of nonrenewable resources. In this sense, they are a fuel-saving technology. An important assumption is how these intermittent sources substitute for nonrenewable capacity. One possible assumption is that intermittent sources displace no nonrenewable capacity. In this case, when wind power is available, it reduces fuel consumption at the marginal generating unit, and it is a pure fuel-saving technology. Another assumption is that intermittent resources can displace some portion of new generating capacity, which is the wind capacity credit. If wind power has a capacity credit of 20 percent, then 100 Mw of wind would displace 20 Mw of new, nonrenewable capacity. In the incremental cost calculation, the incremental cost would become the levelized cost of wind minus the fuel costs of displaced generation and 20 percent of the nonfuel capital costs for displaced new fossil investment. Because combustion turbines are typically used to balance the intermittent supply, wind and solar power will not displace any of

the peak period capacity. To make this calculation, I make assumptions about the marginal nonrenewable resource in different parts of the load curve and the distribution of intermittent power across the load curve.

We use the same assumptions about marginal resources across the load curve for wind and solar. During the base period, intermittent resources substitute for pulverized coal generation. In the shoulder, they substitute for advanced combined cycle plants. In the peak, they substitute for conventional combustion turbine generation. The model is not capable of selecting these resources endogenously, so they are programmed by assumption. The assumptions were based on two factors: levelized costs of resources in each period and the available capacity. In a simplified least-cost minimization, the marginal resource in each period is the one with the highest marginal costs subject to capacity constraints. When iterating through the model, the most expensive nonrenewable resources (i.e., advanced nuclear and gas fired capacity) are either displaced by other renewable sources or removed by conservation. In most runs of the model, the remaining nonrenewable resources in the base and shoulder periods are pulverized coal plants and advanced combined cycle gas plants. In the peak period, conventional combustion turbines are the most expensive generation source and the marginal supply.

Another assumption in the incremental cost calculation for intermittent sources is the distribution of generation over the load curve. For wind, data were not available on the temporal distribution of wind generation and I assume that wind generation matches the distribution of the load curve. I assumed that 70 percent of total generation occurs during the base period, 25 percent during the shoulder, and 5 percent in the peak. This assumption matches the load curve assumed in RFF's Haiku electricity model (Paul and Burtraw, 2002). For solar thermal, our capacity estimates are for the southwestern United States, and recent analysis shows a high correlation between the solar resource and peak demand (Perez et al., 2006; Cohen, 2005). Therefore, the distribution has more weight on the peak and shoulder periods. For solar, 40 percent of generation occurs in the base, 30 percent in the shoulder, and 30 percent in the peak.

Tables A.7 and A.8 illustrate how we use technology cost assumptions to calculate the incremental costs of wind and solar thermal power. We show the incremental cost calculations for two assumptions about capacity credit. We assume a range of 0 to 40 percent for capacity credit.

Table A.7

Sample Cost Comparison for Intermittent Technologies

Cost	Capacity Credit (2004 dollars per mwh)							
			0%			20%		
	Wind	Solar Thermal	Pulverized Coal	Advanced Combined Cycle	Conventional Combustion Turbine	Pulverized Coal	Advanced Combined Cycle	Conventional Combustion Turbine
Capital charge	42.79	106.06	0	0	0	5.19	2.22	0.00
Fixed O&M	8.45	19.39	0	0	0	0.67	0.28	0.00
Variable or fuel	0	0	18.74	38.61	63.95	18.74	38.61	63.95
Transmission	6.91	9.32	0	0	0	0.70	0.58	0.00
Total	58.15	134.77	18.74	38.61	63.95	25.31	41.69	63.95

Table A.7 displays the component costs for wind and solar thermal technologies at the EIA baseline cost level. In the 0 percent capacity credit case, they displace fuel only from the three nonrenewable technologies. In the 20 percent capacity credit case, they displace the full fuel costs but only 20 percent of the nonfuel costs.

Table A.8

Sample Incremental Costs for Intermittent Technologies

Capacity Credit	Incremental Cost (2004 dollars per mwh)	
	Wind	Solar Thermal
0%	32.18	96.51
20	26.82	92.96

Table A.8 shows the incremental costs for wind and solar thermal power for two values of the capacity credit. These figures are calculated by taking the difference in the levelized cost of wind and solar thermal and the total displaced costs of nonrenewable technologies

weighted by the distribution of wind or solar thermal power across the load curve (wind: 70 percent base, 25 percent shoulder, and 5 percent peak; solar thermal: 40 percent base, 30 percent shoulder, and 30 percent peak).

SPECIFYING DEMAND AND SUPPLY ELASTICITIES FOR FOSSIL FUELS AND ELECTRICITY

The electricity model contains a basic supply-and-demand model of the domestic coal and natural gas markets. I use this to project how changes in electric utility demand for natural gas and coal affect prices. Both fuel markets follow the same setup, but I parameterize the models to account for differences in the markets.

I use the following general equation for direct demand for natural gas:

$$Q_d = B \times P^{-e} ,$$

where Q_d is the quantity demanded, B is a constant derived from EIA data, P is the market price, and e is the (absolute) price elasticity of demand.

For market supply of natural gas, I use the following general equation:

$$Q_s = A (P - P_{min})^n ,$$

where Q_s is quantity supplied, A is a constant derived from EIA data, P is the market price, P_{min} is a minimum supply price, and n is a parameter determined by the assumed elasticity of supply. A range of values is considered for the elasticity parameters, as discussed later.

The equilibrium condition for the natural gas market is

$$Q_s = Q_d^{elec} + Q_d^{nonelec} ,$$

which accounts for natural gas demand in the electric- and nonelectric-utility sectors. The constant values are estimated at the equilibrium pairs of demand and price projected in AEO 2006 for 2025 and shown in **Table A.9**.

Table A.9

Natural Gas Market Initial Values

Market	Quantity (quads)	Price (2004 dollars per 1,000 ft ³)
Total supply ^a	25.75	5.43 ^b
Electricity	7.23	6.02
All sectors	18.52	7.69

^a Excludes plant and lease fuels.

^b Projected average lower-48 wellhead price in 2025.

The values shown in Table A.9 come from EIA (2006a, table 13). The price for total supply is the average lower-48 wellhead price for natural gas, and the other prices are for natural gas delivered to consumers. We discuss in the report text and summarize later the assumptions made on the elasticities.

The approach for coal is similar except that nonutility uses are more limited. The initial demand for coal by electric utilities is 27.54 quads, and the initial price is \$1.44 per million BTUs.

These models of fossil fuel supply and demand are used to project new fossil fuel prices in response to changes in electric utility demand for fuels. We also project changes in nonutility demand for fuels and the resulting expenditures. In general, as renewable energy substitutes for coal and natural gas consumption in electric utilities, the market price declines and nonelectric utility demand increases.

To represent electricity demand, we also use a similar functional form:

$$Q_d^{elec} = A \times P_{elec}^{-e},$$

where Q_d^{elec} is quantity of electricity demand, A is a constant estimated with EIA projections for 2025, P_{elec} is the average retail price of electricity estimated in the model, and e is the (absolute) price elasticity of demand. I estimate the A constant using an assumed price elasticity of demand and the equilibrium price/quantity pair from the

AEO 2006 for 2025. The initial electricity demand is 4.945 trillion kwh, and the initial price is \$0.074 per kwh.

ASSUMPTIONS ABOUT BIOMASS AND BIOFUEL COSTS AND CAPACITIES

As described in Chapter Two, the biomass supply model combines assumptions about biomass feedstock capacity, feedstock cost, conversion efficiency, and cost of building and operating production plants to generate marginal cost curves for biofuels. In this appendix, the focus is on the construction of these curves for ethanol derived from cellulosic biomass, since that approach to biofuels has received the most attention so far in policy discussions. However, we also allow for the possibility of biofuels through thermochemical conversion, namely biomass gasification followed by synthesis of transportation fuels using either the FT or methanol-to-gasoline (MTG) approach.

Feedstock Production Capacity and Cost

Future biofuels can potentially come from numerous feedstocks, including agricultural residues, such as corn stover, as well as forestry residues and various dedicated energy crops. The current primary candidates for dedicated energy crops are switchgrass and short-rotation woody crops, such as hybrid poplar and willow trees (Perlack et al., 2005). The potential production capacity for these feedstocks depends on assumptions about future agricultural yields, new harvesting technologies, land use conversion, and constraints on harvesting residues to prevent erosion.

Several recent analyses have estimated potential biofuel supply and show a large range in potential supply and costs. In the 2006 version of the NEMS model, EIA used a maximum capacity of 433 million tons of biomass at costs of less than \$90 per ton. EIA has recently contracted with researchers at the University of Tennessee (UT) to analyze its current capacity projections and supply alternative estimates, and these updated estimates were used in EIA's recent analysis on a 25 percent-renewable-energy requirement and are shown in Figure A.3 (EIA, 2007e). In a 1999 study on potential biomass supply, the Oak Ridge National Laboratory developed a set of biomass supply curves with a maximum potential annual supply of 510 million tons at costs of less than \$90 per ton. In a 2005 study sponsored by DOE and

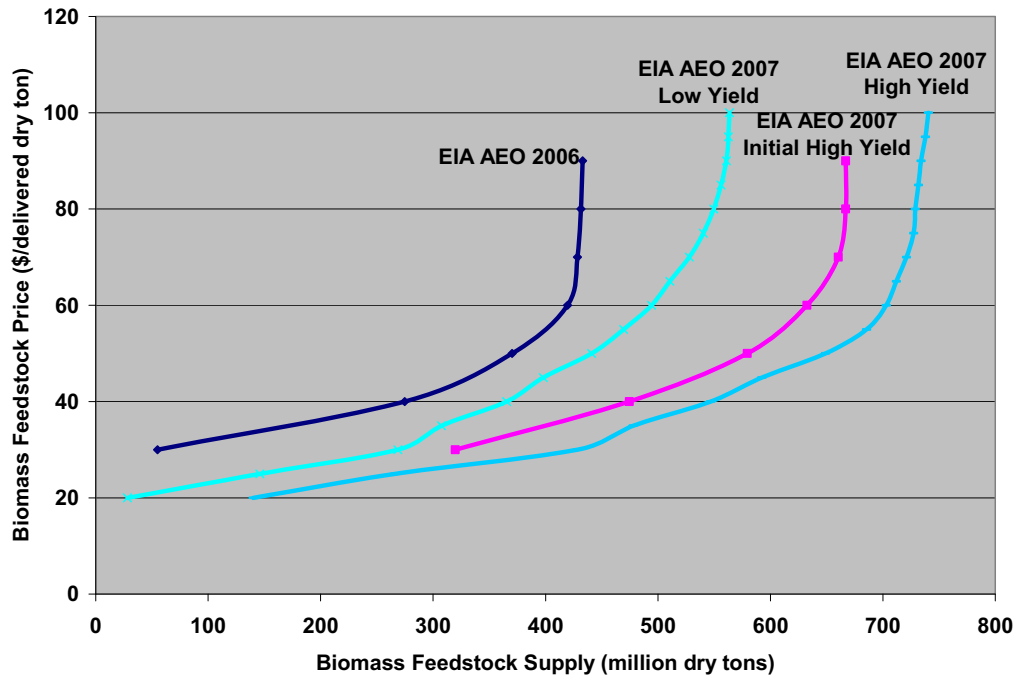
USDA, the research team projected several scenarios of future crop yields, harvesting technologies, and land use conversion. Their analysis showed that, under their range of assumptions, agricultural lands could yield from 400 million tons to 1 billion tons of biomass annually. Forest lands could provide up to 370 million tons of additional biomass (Perlack et al., 2005).

There are several important caveats to the DOE/USDA analysis. The first is that the study used a time horizon of the mid-21st century. The analysis did not attempt to project how the forestry and agricultural industries would reach these targets. Therefore, the estimates provide limited guidance on what these industries could supply by 2025. In addition, the supply projections do not estimate the costs of delivering this supply to a biofuel refinery or a power plant. Consequently, even if industry could supply this level of biomass capacity, consumers may not be willing to pay the price of the fuels derived from them.

The preceding discussion shows the range of potential biomass feedstock capacity from several recent studies. However, the key question for this analysis is how much industry can supply by 2025 and at what levels of cost. I have used three recent estimates of biomass supply as a basis for the range of assumptions, which are shown in **Figure A.3.**

Figure A.3

Biomass Supply Curve Estimates



Sources: Smith, 2008.

The curves show four curves illustrating recent revisions in estimated potential from biomass feedstock. The range of costs in these curves begins at \$20 per ton of delivered biomass feedstock and rises up to \$100 per ton. The cost steps are in \$10-per-ton increments. The first curve is the assumptions used by EIA in the 2006 NEMS model. This curve reaches maximum capacity at 433 million tons and has a greater percentage of biomass in the higher cost levels. The second estimate is a more recent update produced by the University of Tennessee now used in EIA's 2007 analyses. The total supply of biomass in this curve is 562 million tons and reflects a set of lower yield assumptions for biomass yield from wastes and energy crops. The next curve is the "initial high yield" estimate from EIA that we received in advance of the actual AEO 2007 curves shown in the graph. This supply curve reaches its asymptote at 667 million tons of biomass. The final curve shown is the high yield curve for the AEO 2007, which has a maximum supply of 740 million tons. Both of the EIA curves are part of a set of estimates that assume different levels of corn ethanol production. I've selected the curves

with the highest level of corn ethanol produced, which is approximately 25 billion gallons. The level of corn ethanol production affects the asymptote of the graph by changing the amount of land available to produce biomass feedstock at the cost levels shown in the graph. The results show a definite interaction affecting the supply of biomass however the range of variation across the scenarios was only 5%-7% of the total supply available.

As is evident from the graph, considerable uncertainty exists about the potential feedstock availability at the costs considered in this range. In this analysis, I assume a range of biomass supply from 450 million tons to 1 billion tons at costs of up to \$90 per ton. I call this the low-cost biomass supply and assume that this supply comes from waste residues and marginal lands not currently in production. Other sources of biomass are also available. Land currently used for agriculture, pasture, or forestry can be converted to producing energy crops. I assume that biomass from these supplies is the highest-cost supply in the curve and comprises a backstop for biomass supply. That is, at a certain price, an arbitrarily large amount of biomass is available that is sufficient to fulfill demand beyond the supplies available from wastes and marginal lands. I assume a range of potential costs for backstop supplies from \$90 to \$200 per ton, and allow for a wide range because of the great uncertainties in the costs of profitably converting land in future agricultural markets. Some basic analysis using current estimates of land rents and production costs suggests that this is a feasible range.

I established the lower end of our range for land use conversion costs based on estimates of biomass feedstock production costs from ongoing RAND research and recent USDA analysis on land values (National Agricultural Statistics Service and Agricultural Statistics Board, 2007). The USDA 2007 report on land values and cash rents estimates the average cash rent for cropland in the northern plains (including Kansas, Nebraska, North Dakota, and South Dakota) is \$58 per acre and \$30 per acre in the southern plains (including Oklahoma and Texas). I focus on these regions because switchgrass is a native grass to these areas and they have considerable amounts of crop and pasture land. For these reasons, they could potentially produce a large amount of biomass

feedstock under a 25 percent-renewable-energy requirement. Assuming a crop yield of 5 tons per acre, the costs for renting land in these regions to produce biomass feedstock range from \$6 to \$12 per ton of feedstock. Recent RAND analysis has estimated that the production and transportation costs for switchgrass (excluding land rent) were approximately \$70 per ton (Bartis et al., forthcoming). Summing this estimate with the land rent estimate yields a range of \$76 to \$82 per ton in these regions. I increase the lower-bound estimate to \$90 per ton to account for uncertainty in these costs.

For the upper end of the assumed range, I begin with land rent estimates for high-cost cropland. The highest cash-rent estimate in the USDA report is \$340 per acre for irrigated cropland in California. This land, in principle, could be converted into biomass production, especially as it is near major markets for biofuels on the West Coast. The USDA estimate translates into a land rent cost of about \$70 per ton, assuming a yield of 5 tons per acre. Using the same production costs assumed already, the total estimated cost of producing biomass feedstock is \$140 per ton. To allow for uncertainties in these costs, I set the upper end of the range at \$200 per ton.

An important uncertainty unaccounted for in these estimates is that the rising demand for biomass under a 25 percent-renewable-energy requirement could increase agricultural cash rents above the levels in the USDA report. The USDA report already shows that average cash rents have increased every year from 1998 to 2007, with the largest increase from 2006 to 2007. Massive new demand for biomass could accelerate this trend of increasing land rents.

I use one more parameter to characterize the biomass feedstock supply. We assume a range of feedstock distributions indicating the fraction of the low-cost supply available at different costs. This range of distributions is anchored at one end by the distribution of the EIA curve and at the other end by the curve from UT. These distributions give the percentage of total supply within each of the cost levels from \$30 per ton to \$90 per ton. With these two characteristics, low-cost biomass capacity and its distribution by cost, the model encompasses a range of potential supply curves from relatively limited and expensive supply to abundant and inexpensive supply. Beyond these supplies, the

biomass backstop price reflects the prices needed to induce land conversion for energy crop production.

Ethanol Plant Yields, Capital, and Operating Costs

In this analysis, I assumed that corn-based ethanol is constrained to the total in AEO 2006 for 2025 (0.99 quads). The remaining demand for biofuels comes from three resources: cellulosic ethanol, biodiesel, and biomass liquefaction through the FT or MTG method. Biodiesel is constrained to a small fraction of the total requirement (following EIA's capacity assumption); therefore, cellulosic ethanol and derived fuels fulfill the majority of biofuel demand. Because these technologies are not yet in a commercial state,³ there is significant uncertainty in the future costs of these technologies.

I break the biofuel costs into two components:

$$\text{Biofuel cost (\$/ton feedstock)} = \text{Feedstock cost (\$/ton feedstock)} + \text{nonfeedstock cost (\$/ton feedstock)},$$

where nonfeedstock costs include capital costs, variable operating costs, and coproduct value. These cost components are in units of dollars per ton of feedstock. This allows us to vary the conversion yield (gallons of biofuel per ton of feedstock) independently. To convert these costs into unit of dollars per gallon, I divide by the production yield.

I use a range of costs to represent different potential future states of these technologies, with no attempt to separate one from the other in these future states. On the lower end of the range, I use an estimate from Aden et al.'s 2002 report sponsored by NREL. This report described the cost of producing cellulosic ethanol for an "nth-of-a-kind" plant, which represents a new plant that benefits from

³ DOE recently accepted bids on six pilot plants to produce cellulosic ethanol. FT synthesis technology dates back to World War II, and several coal and natural gas-fueled plants exist today. FT plants fueled entirely by biomass are still in a precommercial stage. One of these DOE pilot plants will produce syngas, which is an intermediate step to producing liquid transportation fuels.

efficiencies gained from building and operating a number of several previous plants. The report reflects several optimistic assumptions by the NREL team about reductions not only in delivered feedstock costs, but also in the cost of enzymes and capital costs.

Assuming cost reductions due to learning is an accepted practice in projecting future costs. However, one of the vulnerabilities in making such projections is the reliability of the baseline cost calculation. Earlier RAND research has shown that early cost estimates of new technologies tend to underestimate the true cost of the initial plants (Morrow, Phillips, and Myers, 1981). This occurs as the initial cost estimates use low-definition engineering designs that do not foresee all of the details in a new energy technology. Therefore, when initial plants are built, actual costs almost always exceed projected costs. The RAND analysis showed that early estimates understate the costs of a first-of-a-kind plant by 25 to 50 percent. This underestimate is propagated forward in time when the preconstruction estimates are used as the base for nth-of-a-kind plant costs.

Because of this tendency to understate the costs of new technologies prior to the realization of actual commercial-scale investment experience, I treat the Aden et al. (2002) estimate as a lower (most favorable) bound, and use an estimate of technology cost for investment today while allowing for some learning as an upper bound for the technology cost in 2025. To derive this estimate, we start with a recently published paper by Solomon, Barnes, and Halvorsen (2007) for a first-of-a-kind cellulosic ethanol plant built today. We revised upward the estimate because it assumed a 100 percent capacity factor, and, in our judgment, it did not provide enough of a capital cost contingency to reflect typical capital costs for a first-of-a-kind plant. We recalculated the capital costs to include a 25 percent cost contingency and applied a 90 percent capacity factor. We then allowed for some learning to reduce costs for later plants as production scales up to meet the requirement (Ortiz, 2007).

Table A.10 displays a breakout of the cost assumptions for the Aden et al. (2002) study; the original cost estimate from Solomon, Barnes, and Halvorsen (2007); and the revised Solomon estimate. The table shows that, under the various underlying assumptions discussed

previously, the gasoline gallon-equivalent cost of ethanol ranges from \$1.57 to \$3.74. Note, however, that these figures are based entirely on feedstock costs drawn from the two papers in question. In our uncertainty analysis, we combine ranges of nonfeedstock costs derived from these studies with our own analysis of alternative feedstock costs discussed earlier.

Table A.10

Biofuel Cost Assumptions (2004 dollars per gallon of ethanol, except as indicated)

Cost	Aden et al. (2002)	Solomon, Barnes, and Halvorsen (2007)	Revised Solomon, Barnes, and Halvorsen (2007)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning
Feedstock	0.34	0.66	0.66	0.66
Conversion	0.33	0.67	—	—
Capital	0.51	0.82	—	—
Subtotal: nonfeedstock	0.84	1.49	1.93	1.49
Coproduct credit	-0.09	-0.08	—	—
Total (\$/gallon of ethanol)	1.08	2.08	2.59	2.15
Total (\$/gallon of gasoline equivalent)	1.57	3.01	3.74	3.10

Table A.10 shows assumptions about the cost of delivered biomass to the refinery (feedstock cost), cost of materials (primarily enzymes) and energy in converting biomass to a fuel (conversion cost), amortized capital cost of the refinery, and a coproduct credit from producing electricity that is sold to the electrical grid. The revised estimates have blanks because the new cost estimate was not disaggregated into these categories.

In our analysis, we break the total cost of biofuels into a production cost and feedstock cost. The production cost combines the conversion costs, capital costs, and coproduct credits, and we assume a range of possible values for this cost. The feedstock cost is derived

using the biomass supply curve and an assumed conversion efficiency. We modified the cost-estimate data shown in Table A.10 using assumptions about conversion efficiency, which would allow us to independently parameterize production costs, conversion efficiency, and feedstock supply costs.

In Table A.10, the cost estimates are in units of dollars per gallon. We convert the nonfeedstock-production costs into units of dollars per ton of biomass. This conversion lets us independently parameterize production costs, conversion efficiency, and feedstock supply, yet still maintain a relationship between conversion efficiency and capital cost. The following sample calculations show how we made this conversion. In the Aden et al. (2002) estimate, the nonfeedstock costs are \$0.74 per gallon, and the assumed conversion yield is 90 gallons per ton. The modified nonfeedstock production cost is then \$67 per ton of biomass. For the upper end of our cost range, the revised Solomon estimate with learning, we assume that the costs are double the lower-end value at \$134 per ton of biomass feedstock.

In our uncertainty analysis, we assume a range of conversion efficiencies between 80 gallons per ton and 100 gallons per ton (dry basis). Again, with no commercial-scale plants in production today, this value requires speculation on the future progress in biofuel technology. At the low end of the range, 80 gallons per ton represents a modest improvement in efficiency from estimates of efficiency for proposed pilot plants. In the recent DOE solicitation for cellulosic ethanol pilot plants, the proposed plants ranged in efficiency from about 40 gallons per ton to more than 90 gallons per ton (DOE, 2007b). **Table A.11** displays the projected plant capacities and feedstock rates for these plants. The upper end of the range in our study, 100 gallons per ton, is based on our judgment of the maximum level achievable by 2025. We assume that the very aggressive technology target for 2030 of 116 gallons per ton (Sheehan, 2007) is not reachable by 2025.

Table A.11

Projected Conversion Yields in DOE-Funded Pilot Plants

	Nameplate Capacity (millions of gallons per year)	Actual Capacity ^a (thousands of gallons per day)	Feedstock Input (tons per day)	Conversion Yield (gallons per ton)
Agricultural residue	11.4	28.1	700	40.2
Urban waste	13.9	34.3	770	44.5
Landfill waste	19	46.8	700	66.9
Agricultural residue	31.25	77.1	842	91.5
Agricultural residue	18	44.4	700	63.4
Wood residue	40	98.6	1,200	82.2

Source: DOE (2007).

^a Assumes 90 percent capacity factor.

The following steps show how we combine this information to construct biofuel supply curves. The uncertain variables in the analysis are total feedstock supply, feedstock distribution, nonfeedstock production cost, and conversion efficiency. **Table A.12** shows the quantity estimates of the supply curve using EIA's assumptions about total feedstock and distribution and the conversion yield assumed in the Aden et al. (2002) study (90 gallons per ton).

Table A.12

Sample Biofuel Supply Curve Quantity Estimates

Feedstock Cost Levels (\$ per ton)	Biomass Quantities (millions of tons)	Ethanol (billions of gallons of ethanol)	Ethanol (billions of gallons of gasoline equivalent)
30	57.2	5.14	3.55
40	228.3	20.55	14.18
50	99.4	8.94	6.17
60	51.1	4.60	3.18
70	9.3	0.84	0.58
80	3.1	0.28	0.19
90	1.6	0.14	0.10

Table A.13 shows the cost estimates using the assumed conversion yield of 90 gallons per ton and the two cost estimates described in

Table A.13

Sample Biofuel Supply Curve Price Estimates

Feedstock Cost		Wholesale cost (2004 dollars per gallon of ethanol)		Wholesale cost (2004 dollars per gallon of gasoline equivalent)	
Level (\$/ton)	Cost (\$/gallon)	Aden et al. (2002)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning	Aden et al. (2002)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning
30	0.33	1.08	1.82	1.56	2.64
40	0.44	1.19	1.93	1.72	2.80
50	0.56	1.30	2.04	1.88	2.96
60	0.67	1.41	2.16	2.04	3.12
70	0.78	1.52	2.27	2.20	3.28
80	0.89	1.63	2.38	2.37	3.44
90	1.00	1.74	2.49	2.53	3.60

Table A.12 uses the assumed conversion efficiency to convert the biomass feedstock supply curve into the available quantities for a biofuel supply curve. Table A.13 combines the conversion efficiency and nonfeedstock information to estimate the wholesale costs for biofuels. Also note that biofuel costs can rise above the levels shown in the reports when competition bids up the price of biomass feedstock beyond the upper limit of production costs considered in the supply curves.

Biomass Liquefaction Through Biomass Gasification

Cellulosic ethanol is not the only technology that can potentially produce transportation fuels from cellulosic biomass. Gasifying biomass and producing transportation fuels using either the FT or MTG method is an alternative technological pathway. The FT approach currently operates at commercial scale but using either coal or natural gas. The MTG approach is also commercial but only on natural gas. An advantage of both approaches is that the fuels produced are essentially identical to conventional gasoline and diesel. These fuels could be distributed using the existing infrastructure for the storage and delivery of finished petroleum products. Moreover, utilizing these fuels would require no

major engine modifications, such as the flex-fuel modifications needed to use high-level blends of ethanol, and would result in no fuel economy penalties (in contrast to ethanol-blended fuels).

No commercial-scale biomass-liquefaction plants using thermochemical conversion operate today, and the commercial potential of this technology over the next 20 years is uncertain. The AEO 2006 cites cost estimates for this technology in a similar range of cellulosic ethanol. One estimate of today's production costs was \$3.35 per gallon, decreasing to \$2.43 per gallon by 2020. The crude oil-equivalent price of these estimates is in the high \$80-per-barrel range (EIA, 2006a). When looking at the AEO 2006 estimates for cellulosic ethanol production, production in 2025 above the level required in the 2005 Energy Policy Act (P.L. 109-58) occurs only in the high-oil-price case when oil prices approach the \$80-per-barrel level. This suggests overlapping ranges of uncertainty in production costs for cellulosic ethanol and biofuel produced through thermochemical conversion.

With the level of uncertainty in the cost estimates for these technologies, I assume agnostically that the mix of biofuels produced to meet a 25 percent-renewable policy requirement is split evenly between cellulosic ethanol and thermochemical conversion. I further assume that the mix of fuels from thermochemical conversion is two-thirds diesel and one-third gasoline. With these assumptions, the resulting mix of biofuels matches the current mix of transportation fuels of approximately two-thirds gasoline and one-third diesel.

I acknowledge that these are strong assumptions about the potential of these technologies. But due to the significant uncertainties in all the technologies, current cost projections do not provide the basis to develop supply curves with the level of precision required to estimate how large a share each technology would gain in a future biofuel market. Furthermore, assuming that one technology would progress at the expense of the other could result in a situation in which the majority of the biofuel requirement is met by producing fuels primarily for the gasoline or diesel market. This result introduces complicating details into the analysis of how diesel consumers might cross-subsidize ethanol production to meet a fuel requirement in both the gasoline and diesel markets. Our assumptions focus the analysis on

several of the key factors that drive how this renewables requirement generally could affect energy expenditures. Those include future technology costs relative to conventional fuels, conversion efficiencies, and potential biomass feedstock capacity.

Corn-Based Ethanol

The initial strategy for implementing the 25% requirement maintains EIA's older assumption of constraining corn-based ethanol production to 12 billion gallons. Nearly all this ethanol is used in the baseline amount of gasoline consumption in 2025. In the other strategies, I developed a set of supply curves based on EIA's most recent assumptions and allow an unconstrained amount of corn-based ethanol.

I model the cost of corn-based ethanol with four parameters: initial corn price, corn ethanol yield, change in corn price with ethanol production, and non-feedstock costs. I model the supply of corn-based ethanol in 5 billion gallon increments and each increment of supply increases the price of corn over the previous step in the supply curve. The wholesale cost of corn-based ethanol is then the following:

Wholesale cost of corn-based ethanol (\$/gallon) = (Corn price at cost step_i (\$/bushel) / corn ethanol yield (gallons/bushel)) + Non-feedstock cost of corn ethanol (\$/gallon)

I developed a range of values for the initial corn price, corn ethanol yield, and non-feedstock costs using estimates from EIA's NEMS documentation, USDA estimates of corn prices, historical corn prices, and a USDA survey on the costs of corn ethanol production. I assume a range of initial corn prices from \$2.50 - \$4.00 per bushel. These initial prices reflect the price of corn in 2025 at the baseline level of ethanol production. EIA currently assumes a long-run price of corn at \$3 per bushel, which is based on projections from the USDA. I extend this range by 33% to account for possibly higher corn prices and use a lower bound of \$2.50 to account for improvements in corn production that could reduce prices down toward historical levels. I assume a range of corn ethanol yields from 2.5-3.0 gallons per bushel of corn using

assumptions from EIA's 25 x 25 analysis (2.8 gallons per bushel) and a USDA 2002 survey on ethanol producers (Shapouri and Gallagher, 2005). In this study, they found the range of yields in a sample of ethanol plants was 2.5-2.8 gallons per bushel with a weighted average of 2.7.

I used the same study to develop a range of non-feedstock costs, which includes capital, energy, and labor costs as well as coproduct credits. I assume a range of \$0.10-\$0.55 per gallon of ethanol. Shapouri and Gallagher (2005) found that average non-feedstock costs were \$0.42 per gallon in 1998 and \$0.41 per gallon in 2002. The coproduct value of distillers dried grains was \$0.28 per gallon in 1998 and \$0.25 per gallon in 2002. Therefore, average net costs were \$0.14 in 1998 and \$0.16 in 2002. I adjust this range upwards to account for potentially higher energy costs, because energy prices are nearly double the level from the 2002 study. Furthermore, lower coproduct credits are likely as corn ethanol production expands. With the combination of these factors, I've assumed a large potential for higher variable costs over the level observed in the 2002 survey.

I estimate the rate that corn prices increase with ethanol production based on the results in EIA's 25x25 analysis. EIA's NEMS documentation uses a linear function to approximate price changes when corn demand for ethanol is below 3.7 billion bushels and an exponential function for demand beyond this level. This documentation unfortunately does not include the parameter estimates. I therefore estimate them using EIA's analysis on the 25x25 policy with two rates of change in corn prices. One rate of change for demand from 12 billion gallons to 19 billion gallons and then a second rate for ethanol demand from 19 billion to 25.5 billion gallons. I estimated these values based on Table 13 of the EIA analysis on the 25 x 25 policy, which shows the change in corn prices under several different scenarios that change the demand for corn-based ethanol. With these results, I estimate a rate of \$0.12 per bushel for each billion gallons of corn ethanol production for the initial portion of the curve and a second rate of \$0.32 per bushel for each billion gallons of corn ethanol production.

We recently received EIA's corn ethanol supply curve data for the 2007 AEO, which provide a benchmark for these assumptions (Smith, 2008). EIA estimates the increase in corn prices at successively higher levels

of corn ethanol production and biomass feedstock production. The initial corn price in 2025 ranged from \$3.04 - \$3.74 per bushel, which led me to revise the lower bound on initial corn prices to \$2.50 per bushel in the next revision of the model. The rate of corn price increase with increases in corn ethanol production varies from \$0.26-\$0.30 per bushel per each billion gallons of ethanol production, which is consistent with the estimate I calculated using the results from the 25 x 25 analysis.

Biodiesel

We include biodiesel in this analysis and developed supply curves based on the documentation provided in EIA's NEMS model. EIA allows a total of 200 million gallons of biodiesel from soybean oil and 270 million gallons from yellow grease. This total is approximately four times the amount of biodiesel production in 2005 (NBB, undated).

EIA projects biodiesel costs based on the feedstock, capital, and operating costs minus a coproduct credit for producing glycerin. The main variable cost is the feedstock. EIA uses USDA projections for the price of soybean oil to estimate baseline feedstock costs. Soybean prices are also a function of biodiesel demand, and EIA uses a basic relationship derived from a USDA study estimating how a renewable fuel standard would affect soybean prices (USDA, 2002). EIA models yellow grease prices as a function of soybean prices based on the results of a linear regression model (yellow grease price = 0.49 x soybean oil price). **Table A.14** displays its cost assumptions for the base level of feedstock prices.

Table A.14

Breakdown of Biodiesel Cost Assumptions

Cost	Yellow Grease-Derived Wholesale Price (2004 dollars per gallon)	Soybean Oil-Derived Wholesale Price (2004 dollars per gallon)
Capital	0.14	0.14
Operating	0.46	0.46
Feedstock	2.35	1.15
Coproduct	-0.16	-0.16
Total	2.79	1.59

Source: EIA (2006c).

EIA assumed (based on the USDA projection) that soybean oil costs \$0.305 per pound and the conversion efficiency is 7.7 lb per gallon. The estimated change in soybean oil-feedstock prices due to biodiesel production is \$0.003 per gallon of soybean oil per million gallons of biodiesel produced (in 2004 dollars) (USDA, 2002; Radich, 2004). This estimate of the impact of biodiesel production on soybean oil prices indicates that producing the full 200 million gallons of biodiesel would raise soybean oil prices by \$0.60 per gallon of soybean oil (\$0.08 per pound using the assumed conversion efficiency).

ENERGY EFFICIENCY

I develop cost curves for energy efficiency in the electricity and fuels market based on existing estimates in the literature, basic analysis using some of the literature estimates, and personal judgment where necessary. I treat the supply of energy efficiency similar to the supply of renewable energy. I estimate the cost of energy efficiency in terms of the cost of saved energy (CSE), which is analogous to the levelized cost of energy (LCOE) used in the renewable energy supply curves. I calculate the CSE because most efficiency technologies involve an initial investment in a more efficient capital or consumer good with a future payoff of lower energy consumption. The CSE is then the incremental cost (plus any discounted operating costs) divided by the discounted lifetime energy savings. This gives the cost per unit of energy saved and is then comparable to the levelized energy cost estimates used in the electricity and fuels market. Based on this definition, the CSE calculation involves several components: the

incremental costs of energy efficient technologies, the savings from using the more efficient technology, and a discount rate. Some uncertainty may exist for many technologies in each of these factors. The future cost of energy-saving technologies is a potentially large uncertainty in many cases for similar reasons as discussed for renewable energy (learning that decreases technology costs, potential for breakthroughs that significantly lower costs, etc.). The energy savings are also uncertain for several reasons. The savings from a technology often depends on assumptions about the future baseline level of efficiency or reference technology. For instance, a hybrid engine that improves fuel economy by 30% saves less fuel if the non-hybrid reference vehicle has a fuel economy of 30 MPG instead of 25 MPG. Because the reference technology or baseline efficiency level is uncertain, the savings from adopting a particular technology can vary. In addition, the savings also depends on lifetime pattern of energy demand, which varies across consumers. Finally, any behavioral changes that occur after adopting the higher efficiency technology, such as a rebound effect, affect the lifetime energy savings. For these reasons, even for relatively well-known technologies, there is still uncertainty in the future costs of saved energy.

The second component of the cost curve is the aggregate potential savings at a given cost level. The aggregate savings occur as consumers replace an energy-consuming good, like an automobile or refrigerator, and choose a higher level of efficiency in the new good than they would in the absence of the policy. The aggregate savings for these goods then depends on the savings from individual units and the stock turnover rate among consumers. In many cases, like cars and refrigerators, the turnover rate is slow and any improvements in efficiency take time to increase the overall efficiency of the capital stock. The aggregate savings can also improve with retrofits to existing capital stock. For many homes and commercial buildings, low-cost energy savings are possible by retrofitting them with energy-saving lighting and improving insulation. The options to improve vehicle efficiency with retrofitting are more limited and typically costly though. For this reason, this analysis only considers higher efficiency on new vehicles.

In the recent literature assessing energy efficiency, several studies assessed the aggregate potential for energy savings in both fuels and electricity (Creys et al., 2007; EIA, 2005a; NHTSA, 2008). However, none of these studies documented their technology cost assumptions and energy savings calculations in sufficient detail to use directly in this study. There are additional studies that document technology cost estimates in detail, but do not combine the estimates with analysis on the aggregate savings potential (NRC, 2002; Greene et al., 2005; Rosenquist et al., 2004; AAM, 2008). Because no individual study provides both the technical detail on cost estimates and analysis on aggregate energy saving potential, I've developed the cost curves in this analysis drawing from each of the studies. The details on the costs curves in each market are below.

Fuels Market

Several recent studies have estimated the costs and energy savings potential for vehicle efficiency improvements. Creys et al. (2007) develop carbon abatement cost curves for the U.S. transportation sector. NHTSA (2008) analyzes the incremental costs and fuel saving potential of several different levels of vehicle efficiency improvements in support of rulemaking on CAFÉ standards. EIA (2005a) analyzes a CAFÉ standard proposed by the National Commission on Energy Policy (NCEP) using the NEMS model to estimate increases in vehicle costs and aggregate fuel savings. NRC (2002) estimated the costs of increasing vehicle fuel economy using commercially available technologies to improve the internal combustion engine. Several subsequent studies have used these estimates as the basis of their cost assumptions. Both NHTSA (2008) and EIA (2005a) draw cost estimates from this analysis. Greene et al. (2005) uses a vehicle efficiency improvement cost function in his analysis of feebates that is parameterized with the NRC (2002) estimates. Finally, the American Automobile Manufacturers (2008) provides an alternative set of technology costs based on manufacturer experience. Each of these studies provides important information in estimating cost curves for saving fuel; however, they also all are missing key details in how they arrive at their estimates. The

remainder of this section describes these studies and the key information drawn from them in developing the cost curves used in this study.

Creyts et al. (2007) estimate the life-cycle costs and potential reductions in greenhouse gasses from improvements in vehicle efficiency. They show a large potential for reductions from improving efficiency in light-duty vehicles and freight trucks. An important note is that their study focuses on 2030. **Table A.15** summarizes their results:

Table A.15
Vehicle Efficiency Estimates from Creyts et al. (2007)

Source	New Fuel Economy / % Increase (MPG%)	Incremental Cost (\$)	Average cost (2005\$/tonne CO2eq)	CO2 Reduction Potential in 2030 (megatonnes CO2eq)	Estimated 2030 fuel savings (billion gallons gasoline equivalent)
Increased fuel economy in passenger cars	38 MPG / 15%	\$700 - \$1400	-81	95	10.7
Increased fuel economy in light trucks	28 MPG / 8%	\$700 - \$1400	-69	70	7.9
Increased fuel economy in freight transport	13% medium trucks 6% heavy trucks	\$5200 - \$9400	-8	30	3.4
Addition of light-duty plug-in hybrids	cars - 113 MPG light trucks - 79 MPG	\$4300 - \$5300	15	20	2.2

Adapted from Creyts et al. (2007).

The first column in the table shows the source of greenhouse gas reductions. The second column shows the anticipated efficiency improvements. The third column has their technology cost assumptions. The fourth and fifth columns contain their estimates of the average costs and absolute amounts of emissions reductions. In the final column, I convert the CO2 reductions into fuel savings using their estimate of CO2 emissions for gasoline (8.9 kg per gallon).

The table shows that Creyts et al. (2007) estimate improvements in passenger cars and light trucks can save an estimated 18.6 billion gallons of gasoline per year by 2030, which is 10% of the 2030 light-duty vehicle fuel demand projected in EIA's 2007 AEO. Efficiency improvements for freight trucks and addition of plug-in hybrids would bring additional savings. Creyts et al. (2007) also estimate that the average life-cycle costs of improvements to passenger cars, light trucks, and freight trucks could come at negative costs (a net savings to consumers). They estimate the average cost by calculating the

difference between the incremental cost and the net present value of lifetime fuel savings divided by the reduction in emissions.

Unfortunately, their documentation is unclear on the details of their calculation and directly applying the estimates by Creyts et al. (2007) to this analysis has several problems. The main problem is that their assumptions in estimating the lifecycle costs are not displayed explicitly in the report and cannot be examined, except that they note their assumption that the world oil price is \$59 dollars per barrel in 2030. They show their incremental cost assumptions but without more detail on how they estimate fuel savings I cannot reproduce their estimates. The second problem is that their analysis focuses on 2030 so the cost reductions from learning effects and introductions of new technologies (like plug-in hybrids) are difficult to apply to 2025. Nonetheless, this analysis is useful to help define a range of costs, the relative ranking of different technologies, and their relative potential to save fuel. Some recent analysis in NHTSA (2008) provides the most current, disaggregated analysis on the costs of vehicle efficiency, and also offers a set of assumptions that can be applied to the Creyts et al. analysis.

NHTSA (2008) is a technical analysis to support rulemaking for the 2011-2015 time period based on the recent increases in CAFÉ standards contained in the Energy Independence and Security Act (EISA) of 2007. NHTSA collected data on auto manufacturer product plans and cost data from manufacturers and vendors of efficiency technology components to estimate the costs of several different potential increases vehicle fuel economy. They estimate the "optimized" level of efficiency where the marginal costs equal the marginal benefits and then several levels of efficiency above and below the "optimized" level. In making these estimates, they explicitly state their assumptions on lifetime vehicle use, discount rates, rebound effect. With these details, estimating the CSE for vehicle efficiency is straightforward. A key element missing from NHTSA's analysis though is the fuel saved in future years by initiating vehicle efficiency improvements in 2011-2015. NHTSA estimates the total fuel saved over the lifetime of the vehicles in each model year but this does not translate easily into estimates of annual demand reductions in 2025. For these estimates, a recent analysis in

EIA (2005A) is useful to quantify the fuel savings in 2025 by improving vehicle efficiency in earlier years.

In 2005, EIA used the NEMS model to analyze a set of policy recommendations by the NCEP. One of NCEP's proposals was to raise CAFÉ standards by 10 mpg for cars and 8 mpg for light trucks between 2010-2015, which results in average fuel economy of 37.5 mpg for passenger cars and 30.3 mpg for light trucks. EIA's analysis of this proposal found that average vehicle prices increase to a maximum of 5% above the reference case in 2015, which is a \$1750 price increase in 2003\$. After reaching the peak in 2015, the price change from the policy declines to a 4 percent increase over the reference case in 2025, which equated to \$1200 (2003\$). The NCEP's CAFÉ proposal reduces 2025 petroleum demand for passenger cars by 0.93 quads, which is a 9.8% decline from the reference case value. For light trucks, the fuel economy increase reduces petroleum demand by 2.21 quads, which is a 15% decline. Overall, the fuel economy increase reduces 2025 light-duty vehicle petroleum consumption by 13%. This EIA analysis provides estimates that are directly applicable to 2025 but the efficiency cost estimates are still highly aggregated.

The fuel economy levels in the NCEP proposal correspond with the level of efficiency in NHTSA's "50% above optimized" case. NHTSA estimates that in this case the incremental technology costs for passenger cars are \$1694 and \$2041 for light trucks. With these cost estimates combined with NHTSA's assumptions about vehicle miles travelled, vehicle survivability, rebound effect, and discount rate, I estimate the cost per gallon of fuel saved (incremental costs divided by the gallons of fuel saved over the vehicle's lifetime). I've estimated the costs per fuel savings for a range of rebound factors and discount rates for both passenger cars and light trucks. The tables below show these results.

Table A.16

Estimated Passenger Cars Costs per Fuel Savings (\$/gallon)

		Rebound Factor		
		10%	15%	20%
Discount Rate	3%	2.55	2.70	2.87
	7%	3.26	3.45	3.66
	10%	3.82	4.04	4.30
	13%	4.31	4.56	4.85

Table A.17

Estimated Light Truck Costs per Fuel Savings (\$/gallon)

		Rebound Factor		
		10%	15%	20%
Discount Rate	3%	3.03	3.84	4.68
	7%	3.16	4.00	4.88
	10%	3.26	4.14	5.04
	13%	3.35	4.25	5.18

The tables show the range of CSE in units of \$/gallon saved as the discount rate and rebound factor vary. Both of these factors affect the amount of lifetime fuel savings from an improvement in efficiency. As the rebound factor and discount rate increases, the total number of gallons of fuel saved decrease. Most benefit-cost analyses of fuel economy vary these parameters because the magnitude of the rebound effect remains an uncertainty in the literature. In addition, analysts make different assumptions about the discount factor. Current OMB practice is to use both 3% and 7%, but many analysts within the auto industry argue that consumers' purchasing decisions reveal higher implied discount rates closer to 13%.

The rebound effect refers to the increase in vehicle use that occurs with efficiency improvements. Increasing vehicle efficiency reduces the cost of driving, and drivers will respond by driving additional miles. The magnitude of this additional driving remains under debate. Greening et al.(2000) found a range of 10%-30% in a

survey of the literature on transportation demand. A recent analysis found that the rebound effect may have declined. Small and Van Dender (2007) analyzed data from 1966-2001 and estimate a rebound effect over the entire period of 22% but this effect decline substantially to 11% when looking at the later portion of the sample (1997-2001). The smaller rebound effect occurs with rising incomes; however, rising prices increase the rebound effect. Therefore, this parameter may have increased again with recent rises in fuel prices. Based on this range in the literature, I varied the rebound effect from 10%-20% in the tables shown.

Just based on this variation in rebound effect and discount rates, the potential costs of fuel saved vary across a wide range for both passenger cars and light trucks. The costs of fuel saved are generally lower for passenger cars but in cases with low rebound factor and high discount rates the relative position shifts.

A final uncertain factor affecting the CSE is the incremental technology cost. The tables above used the incremental cost estimates in NHTSA (2008) for their "50% above optimized" case. Their estimates come from several sources. They use prior research contained in NRC (2002) but also obtain proprietary data from vehicle manufacturers, technology cost estimates from vehicle component vendors, and consulting companies. The results in EIA (2005A) suggest that technology costs may be lower than NHTSA's estimates. The average vehicle price increase in EIA's analysis of a similar CAFÉ proposal was approximately 35% lower than NHTSA (2008). NHTSA's estimates are approximately consistent with the high-cost estimates in Greene et al. (2005). In this analysis, Greene et al. (2005) present parameterized equations of the NRC (2002) estimates, and also present low-cost and high-cost cases. Their middle range estimate is approximately 20% below NHTSA's estimate and the low-cost case is 40% lower. In comments to NHTSA, the American Automobile Manufacturers (AAM) offer evidence of potentially higher costs for efficiency improvements. I note these in greater detail below.

I use these ranges shown in Figures A.16 and A.17 to define two steps in the cost curves for vehicle efficiency. I assume the initial lower cost measures are improvements to passenger cars and a higher cost set of measures includes improvements to light trucks. The initial step

of the curve varies from \$2.00 to \$4.85 per gallon of fuel saved. In Table A.16, the CSE varies from \$2.55 to \$4.85 per gallon based on variation in the discount rate and rebound factor. For the low end of the range, I allow costs 20% lower than NHTSA's assumptions based on the results in EIA (2005A) and Greene et al. (2005). These studies showed potential for costs nearly 40% below NHTSA's estimate. I've assumed 20% lower costs to remain more conservative with this assumption.

The second step of the cost curve uses an escalation factor to increase costs relative to the initial step. NHTSA (2008) assumes that technology costs increase approximately 20% for light trucks. Greene et al. (2005) and Creyts et al. (2007) assume very small cost differences across these classes. The AAM estimates suggest potentially large cost differences. In their comments on NHTSA's analysis, the AAM cites a series of studies (funded by AAM) that contest the technology cost estimates and benefit-cost analysis in NHTSA (2008). Both studies cited by the AAM use simulation models to estimate the technologies that auto manufacturers will choose to meet the CAFÉ standards. Varying the individual technology costs leads to different technology choices by manufacturers. Furthermore, NHTSA assumed that certain manufacturers, such as BMW and Porsche, would choose to pay fines instead of using more efficient technologies because their consumers place a high premium on vehicle performance. The Sierra Associates study cited by the AAM changes this assumption and finds much higher compliance costs on average. With these assumptions, the Sierra Associates analysis found that the average incremental costs for light trucks were \$3262, which is about 60% above NHTSA's estimate. Based on this range of estimates, I allow the cost escalation in the second step to vary between 0%-50% from the initial costs. The low end of this range represents costs savings on par with smaller vehicles and the high end of the range allows for much higher costs, as argued by the AAM.

In the final step of the cost curve, I allow for some improvements in freight truck vehicle efficiency. Limited research exists on potential for freight truck improvements in comparison to the work on light-duty vehicles. This is primarily because no fuel economy standard currently exists for freight trucks. Creyts et al. (2007) and NCEP (2004) both have some preliminary estimates on technology costs but no

detailed simulations have been done such as EIA's analysis with the NEMS model or NHTSA's analysis. For these reasons, I base this portion of the cost curve on the analysis by Creyts et al. (2007). I use a range centered on their relative increase in costs over the initial level and relative potential for savings. They estimate that freight truck improvements will cost about 90% more than improvements to passenger car efficiency and I allow 10% variation around the 90% increase. In their analysis, the freight truck improvements comprise approximately 15% of the total fuel savings, which I maintain in this analysis. I also assume that the remaining 85% of the potential savings is split evenly between passenger car and light truck savings. There was uncertainty in the existing analysis on this. EIA's analysis with the NEMS model found that light truck savings comprised over 70% of the fuel savings from higher CAFÉ standards. However, Creyts et al. (2007) found that passenger cars savings made up almost 60% of the potential savings in their analysis. With this degree of uncertainty, I chose to make the shares equal.

The final assumption in developing these cost curves is the overall savings potential. The total potential for savings in the fuels market is limited by the fact that new cars purchases are a small proportion of the vehicle fleet. Therefore, improving the fuel economy of new cars slowly affects the overall efficiency of the vehicle fleet. Without a model of the vehicle stock, I've drawn heavily on the studies that perform this analysis. EIA (2005A) estimates the aggregate fuel saving potential from NCEP's CAFÉ proposal at a 13% decline from 2025 reference level fuel consumption. Creyts et al. (2007) estimate a 10% decrease in fuel consumption in their analysis. Based on these estimates, I assumed that total potential efficiency in the fuels market varies from 10%-12.5% of initial consumption.

Based on these assumptions the cost curves in the fuels market have the following values:

Figure A.18

Range of Assumptions Used in Vehicle Efficiency Cost Curves

Vehicle type	Cost of fuel saved (\$ per gallon)	Cost Increase over Initial Cost (%)	% of Total Potential savings (%)	Potential savings (quads)
Passenger cars	2.00 - 4.85	-	42.5%	1.23 - 1.53
Light trucks	2.00 - 7.28	0%-50%	42.5%	1.23 - 1.53
Freight trucks	3.60 - 9.70	80%-100%	15%	0.44 - 0.54

Figure A.18 shows the three steps in the cost curve and the vehicle type assumed for each step in the curve. The second column shows the ranges of CSE for each step in the curve. The range of the values in the initial step is an assumption and costs in the two remaining steps increase according to the escalation factors shown in the third column. These escalation factors shown in the second and third steps are also parameters that I've assumed based on the discussion above. The final two columns show the potential energy savings in each step of the curve. I allow a vehicle efficiency to account for 10%-12.5% of the total 2025 fuel consumption. I then divide up this total potential according to the distribution in the fourth column. The final column is the actual potential energy savings in units of quads.

Electricity Market

Similar to the fuels market, no studies were directly applicable to this analysis and I have adapted estimates on the costs and potential for electricity savings from several studies. I again draw from the Creyts et al. (2007) study of carbon-reduction opportunities in the U.S. by 2030. I've also drawn from studies for the NCEP. The NCEP proposed increasing energy efficiency with more stringent building codes and technology standards. In support of this recommendation, they commissioned analysis on commercial and residential electricity savings technologies by the Lawrence Berkeley National Lab (LBNL) and this study has very detailed information on the costs of these technologies (Rosenquist et al., 2004). The EIA (2005a) study that assessed higher

CAFÉ standards for NCEP also analyzed the impact of this proposal for more stringent building codes and technology standards on electricity demand.

The LBNL and EIA studies have detailed estimates on the potential for energy savings from building codes and technology standards; however, this analysis leaves out energy savings that can come from retrofitting existing homes and commercial buildings with more efficient technology. The Creyts et al. (2007) study provides the most comprehensive estimates of energy savings in the electricity sector, and I begin developing the cost curves with their estimates.

Figure A.19 shows their estimates for the electricity sector:

Figure A.19
Creyts et al. (2007) Estimates of Electricity Efficiency Potential

Energy Use	Average cost (\$/metric ton CO2eq)	Potential CO2 Reduction (million metric ton CO2 eq)	Potential Electricity Savings (billion kwh)	Estimated Average Cost (cents/kwh)	Estimated Cost per Savings (cents/kwh)
Lighting	-87	240	393	-5.31	2.7
Electric equipment	-93	120	197	-5.67	2.3
HVAC equipment	45	100	164	2.75	10.7
Combined heat and power	-36	70	115	-2.20	5.8
Building shell	-42	60	98	-2.56	5.4
Residential water heaters	-8	50	82	-0.49	7.5
Other	-	70	115	-	-

The first column in the table shows the categories they used to group the technologies. The second column is their estimate of the average costs of greenhouse gas reduction and the third is their estimate of the greenhouse gas reduction potential. The fourth column converts the greenhouse gas reduction potential into electricity savings potential. I make this calculation using their estimate of U.S. carbon intensity of electricity production (1kwh = 0.61 kg of CO2). I also use the same conversion factor to calculate the average costs in units of \$ per kwh, which is shown in the fifth column. In the final column, I've made several assumptions to calculate the CSE from these technologies, which are detailed below.

The second column gives the difference in the incremental technology costs and NPV energy savings divided by the CO2 reduction. This has the following form:

$$\text{Average costs} = \frac{\text{Incremental cost} - \sum \text{NPV energysavings}}{\text{Greenhouse gas reduction}}$$

After converting the greenhouse gas reductions to electricity savings, this has the form:

$$\text{Average costs} = \frac{\text{Incremental cost} - \sum \text{NPV energysavings}}{\text{Electricity savings}}$$

This step converts the estimates of GHG reductions into energy savings using the assumed carbon-intensity of U.S. electricity production. Creyts et al. (2007) assume that 1 kwh of electricity produces 0.61 kg of CO₂ equivalent emissions.

Now, I estimate the average electricity savings with the average electricity price over the analysis period, which I take from EIA's projection in the AEO 2007:

$$\frac{\text{Incremental cost}}{\text{Electricity savings}} = \text{Average costs} + \text{Average electricity Price}$$

The incremental cost divided by the electricity savings is the cost of saved energy (CSE). Therefore, with these assumptions, I can estimate the CSE from Creyts et al. analysis. A key assumption is that the average electricity price is representative of the average NPV savings. If the price varies considerably over the time period then the average price may diverge from the NPV; however, in this case, EIA's price projections are relatively stable over their forecast period. The average electricity price in the AEO 2008 was 8 cents per kwh.

Because these estimates contain a considerable amount of missing information, I compare them with recent cost estimates in the LBNL study by Rosenquist et al. (2004). **Table A.20** compares these estimates:

Table A.20

Comparison of Estimated CSE with LBNL Estimates

Energy Use	Estimated Cost per Savings from Creyts et al. (2007) (cents/kwh)	LBNL Residential Sector Estimate (cents/kwh)	LBNL Commercial Sector Estimate (cents/kwh)
Lighting	2.7	5.9	1.1 - 2.9
Electric equipment	2.3	0.5	0.1 - 0.2
HVAC equipment	10.7	2.9 - 4.5	1.7 - 7.8
Combined heat and power	5.8	-	-
Building shell	5.4	3.1 - 5.6	4.0 - 17
Residential water heaters	7.5	3.9	-

The table shows the same categories of savings as the previous table and compares the estimates costs of CSE with the figures from LBNL in both the residential and commercial sectors. An important note is that the focus of the LBNL study was estimating technology costs for building codes and technology standards. Therefore, they only considered improvements in new equipment and construction. Creyts et al. also considered retrofits to existing buildings and appliances. Another consideration is that the Creyts et al. estimates average across sectors. Nonetheless, the LBNL study provides a comparison to determine if the estimated values from the Creyts et al. study are within a reasonable range of the estimates with better documentation. The table shows that the estimates for lighting and building shell improvements are within the range of estimates from the LBNL study but that the estimates from the other categories are above LBNL estimates.

Based on the uncertainties with these costs, I chose to assume a range of costs for the lowest cost portion of the cost curve and use the analysis from Creyts et al. (2007) to help define how costs increase and the energy saving potential for the different groups of technologies. I assumed that improvements to electric equipment and lighting comprise the two lowest steps in the cost curve (electric equipment lowest and lighting next) with a limited cost increase in the second step. The improvements in electric equipment are for new appliances but the

savings from lighting occur for both new residences and retrofits in existing homes and buildings. The third step represents efficiency improvements from improvements in building shells and the final step applies to heating, ventilation, and air conditioning (HVAC) equipment. The LBNL analysis assumes that installing these technologies primarily saves electricity for the consumer. I've excluded the combined heat and power and residential water heater categories from this analysis because they include a mix of fuel sources.

The next parameter used in the cost curves is the electricity savings potential. Recent studies show a wide range of savings potential in the electricity sector. The EIA analysis of NCEP's recommendations found that the building codes and technology standards would reduce electricity demand in 2025 by 3%, which was 174 billion kwh in their analysis (EIA, 2005a). The technologies I've included from Creyts et al. (2007) sum to 732 billion kwh which is 14% of EIA's AEO 2007 projected electricity generation in 2030. In its 2007 Vision Plan, the National Action Plan for Energy Efficiency, a group of electric utilities, regulators, and environmental groups, estimates that implementing all cost-effective energy efficiency technologies could reduce load growth in 2025 by 50%, which is a 20% savings in electricity. Their analysis assumes that the average cost of the efficiency technologies used to reach this goal is 3.5 cents per kwh (National Action Plan for Energy Efficiency, 2007). Based on this range of estimates, I assume energy efficiency in the electricity sector has a total potential savings from 10%-15% of 2025 electricity demand. I divide the share of the savings in each step of the curve primarily based on the analysis in Creyts et al. (2007). They find the large majority of the potential savings comes from improvements in lighting and electric equipment. I assumed each of these groups of technologies has 30% of the total potential. The remaining two categories can save an additional 20% of the total. With these assumptions on the range of costs and electricity saving potential, the cost curves used for the electricity sector are shown in **Table A.21**.

Table A.21

Range of Assumptions in Electricity Efficiency Cost Curves

Category	Cost of Saved Electricity (cents/kwh)	Cost Increase over Initial Cost (%)	% of Total Potential Savings	Savings Potential (bill kwh)
Electric equipment	3 - 6	-	30%	148 – 223
Lighting	3 - 7.5	0%-25%	30%	148 – 223
Building shell	5.25 - 13.5	75%-125%	20%	99 – 148
HVAC equipment	7.5 - 18	150%-200%	20%	99 – 148

Figure A.21 shows the four steps in the cost curve and the source of electricity savings for each step in the curve. The second column shows the ranges of CSE for each step in the curve. The range of the values in the initial step is an assumption and costs in the three remaining steps increase according to the escalation factors shown in the third column. The escalation factors shown in steps two through four are also parameters that I've assumed based on the discussion above. The final two columns show the potential energy savings in each step of the curve. I allow a electricity efficiency to account for 10%-15% of the total 2025 electricity consumption. I then divide up this total potential according to the distribution in the fourth column. The final column is the actual potential electricity savings in units of billion kwh.

MODELING PETROLEUM MARKET PRICES

I use a simple representation of the world crude oil market to model how changes in U.S. demand for crude oil due to the renewables requirement affect world oil prices, which then affect the price of gasoline and diesel. This demand-and-supply model follows a similar structure to the demand-and-supply model described earlier for the natural gas and coal markets. Oil demand is described by the following equation:

$$Q_d^{oil} = A \times P_{oil}^{-e},$$

where Q_d^{oil} is oil demand from a consumer, P_{oil} is the world oil price, A is a constant estimated with EIA projections, and e is the absolute price elasticity of demand. The supply equation is

$$Q_s^{oil} = B (P - P_{min})^n,$$

where Q_s^{oil} is the quantity of oil supplied by a producer, B is a constant derived from EIA projections, P is the world price of oil, P_{min} is a minimum price to supply oil, and n is a parameter determined by the assumed supply elasticity of oil. The following equilibrium condition applies in this model:

$$Q_s^{oil} = Q_d^{U.S. trans} + Q_d^{U.S. nontrans} + Q_d^{rest of world}.$$

In other words, world oil supply must equal the demand from the U.S. transportation demand sector, U.S. nontransport demand, and demand from the rest of the world. I parameterize the three demand equations using the equilibrium quantity and price pairs from EIA's AEO 2006 projection for 2025 in the reference case. **Table A.22** displays these values.

Table A.22

Petroleum Market Initial Values: AEO 2006 Projections for 2025

Projection	Quantity (millions of barrels per day)	Price (2004 dollars per barrel)
World supply	110.87	47.99
U.S. total ^a	26.12	47.99
U.S. transport	18.59	47.99
U.S. nontransport	7.46	47.99
EIA discrepancy	0.07	—
Non-U.S. demand	84.58	47.99

Source: EIA (2006a, tables 11, 12, 20).

^a 0.07 million-barrel-per-day discrepancy from EIA added to total.

Table A.22 shows the initial values used in the petroleum market models. The price information refers to imported crude oil, and all of the figures are EIA's projection for 2025.

I readily acknowledge that the representation of world oil supply glosses over numerous issues related to the market power of large petroleum-exporting countries and objectives other than discounted net present value maximization for state-influenced producing companies (e.g., revenue targets for debt service, financing current consumption, maintaining long-term economic sustainability). By looking at a range of supply elasticity values in addition to demand elasticities, I can show how U.S. crude oil demand displacement by biofuels might affect the world price of crude oil under different degrees of tightness or looseness of supply, without linking those conditions back to different assumptions about supplier behavior. One task for future research is the coupling of our framework for biofuels with a more complicated model of the world oil market, as for example in Bartis, Camm, and Ortiz (forthcoming).

With this supply-and-demand model, I can calculate world oil-price response to changes in U.S. demand. The prices of retail gasoline and

diesel are then a markup on the price of oil to account for refining, marketing, and transportation costs, as well as state and federal taxes. These markups are based on EIA projections. **Table A.23** shows their values.

Table A.23

EIA 2025 Projections of Petroleum Product Prices

Factor	Price (2004 dollars per gallon)	
	Gasoline	Diesel
Oil price	1.14	1.14
Wholesale price	1.53	1.52
State taxes	0.24	0.21
Federal taxes	0.11	0.14
Retail price	2.13	2.07

Source: EIA (2006a, table 100).

TRANSPORTATION ENERGY DEMAND

We model transportation energy demand using the same aggregate demand equation as in the markets for natural gas, coal, and electricity. The equation constant is estimated using equilibrium values from the AEO 2006 reference case in 2025, which are shown in **Table A.24**.

Table A.24

Initial Transportation Demand Values: Motor Transportation Fuel Demand (quads)

Vehicle	Gasoline	Diesel
Light duty	20.55	0.86
Commercial light trucks	0.8	—
Freight trucks	0.27	6.55

Source: EIA (2006a, table 34).

Table A.24 shows initial gasoline and diesel demand for the three sectors of the transportation fuel market included in this analysis. We selected these sectors because they account for nearly all current biofuel demand and comprise almost 80 percent of total transportation energy demand.

VALUES OF ENERGY SUPPLY AND DEMAND ELASTICITIES

As noted in the main text, part of our sensitivity analysis included different values for key supply and demand elasticities in the model. **Table A.25** summarizes the ranges of values for the elasticities whose values we varied. The elasticities of nonelectric natural gas demand in the United States, nontransportation oil demand in the United States, and non-U.S. total oil demand were set at -0.5, 0.5, and -0.4, respectively.

Table A.25
Assumed Elasticity Values

Elasticity	Elasticity Value		
	Low	Nominal	High
Transportation fuel demand*	0.2	0.5	0.8
Oil supply	0.2	0.4	0.6
Electricity demand*	0.2	0.4	0.6
Natural gas supply	0.2	0.4	0.6
Coal supply	0.7	1	1.3

* absolute values used for demand elasticities

IMPACTS ON ENERGY EXPENDITURES

If we let the subscript 1 denote variables with the renewable requirement and 0 denote corresponding values without the requirement, then it follows that the change in total expenditure, price multiplied by quantity, satisfies

$$P_1 Q_1 - P_0 Q_0 = (P_1 - P_0) Q_0 - P_1 (Q_0 - Q_1).$$

That is, the change in expenditure can be represented as the increase in the payment for the original quantity minus the reduction in quantity evaluated at the new price. This conceptual representation allows us to discuss the factors that we would expect to most substantially influence the changes in expenditures for fuels and electricity with the renewables requirements, given the expectation that, in many cases, at least, the costs of the alternative resources will be higher than the fossil resources they replace.

In the case of electricity, one obvious influence is how rapidly the incremental cost of substituting renewable for fossil-generated electricity rises as the total amount of renewables use expands. Given

our simplifying assumption of average cost electricity pricing, this curve will influence how much the price of electricity must rise to cover costs. Note, however, that, while the average price will depend on the amount used and the cost per unit of each type of renewable introduced, the averaging of these factors into the price reduces the influence of errors in the specification of any one cost factor. This would not be the case if we were estimating changes in economic surplus, where the incremental costs of each technology affect the size of the net consumer plus producer surplus. This is one of the reasons that changes in expenditure are not a reliable guide to impacts on overall economic efficiency (though impacts on total surplus would need to be broken down into effects on consumers and producers to show the incidence of impacts).

Another important influence is the elasticity of electricity demand. The averaging of higher cost renewables into the price of electricity has an effect on demand broadly similar to a tax on the final product. That, in turn, will reduce total demand, and, since the target is specified in terms of 25 percent of total demand, lower demand implies less need for the most expensive renewable alternatives. The more elastic the demand (that is, the more demand proportionately falls with a rise in price), the stronger this effect. The elasticities of supply for natural gas and coal also are relevant, since the displacement of demands for these fuels by the relative decline in fossil-based generation will lower their prices and thus the costs of remaining fossil generation (as well as the cost of natural gas direct end use). In our sensitivity analyses, however, we tend to find that the demand elasticity is a stronger influence (since fuel costs are only part of total generation costs).

Broadly similar reasoning applies to the expenditure impacts of renewable fuel requirements, though here we must keep in mind the differences in possible mechanisms for pricing. The steepness of the overall supply curve for renewable fuels (taking into account all influences on feedstock and other costs, as discussed in Chapter Three), is one obvious influence. If transportation fuel prices rise under the renewables requirement, either because of a revenue-neutral cross-subsidy from nonrenewable to renewable fuels or because of marginal cost

pricing in which renewable costs set the price, then transportation fuel demand will fall. The more elastic is this demand, the less will be the relative need to utilize more-expensive renewables. This effect does not arise if the government directly subsidizes renewable fuels out of general revenues to maintain their price at parity with fossil alternatives; in this case, the lack of a conservation effect will raise government outlays relative to a scenario in which prices are allowed to rise. In the case of marginal cost pricing, in contrast, a larger increase in consumer expenditure can be anticipated, reflected in part in large transfers in revenues from consumers to fossil energy producers that receive prices above their costs.

The other important factor in this case is the elasticity of petroleum supply available for transportation (taking into account supply elasticities in various geographical regions and nontransportation oil demands). The renewables requirement for transportation, by reducing demand for petroleum, puts downward pressure on crude oil prices and, thus, gasoline and diesel prices. The more inelastic this net supply, the more the demand drop will translate into lower gasoline and diesel prices and thus lower expenditures for fossil transportation fuels (though this would, in turn, stimulate demand).

CALCULATION OF NET CO₂ IMPACTS

Electricity

In the electricity sector, the model calculates the mix of renewable resources used to meet the policy requirement. By construction, the model also calculates the nonrenewable resources for which the new electricity sources substitute. By calculating the net difference between CO₂ emissions from the renewable and nonrenewable sources, we can estimate the change in CO₂ emissions from renewable electricity. Formally, the calculation is

$$\sum_i \sum_j (CO_2_j^{NR} - CO_2_i^R) \times Generation_{i,j} ,$$

where $CO_2_j^{NR}$ is the life-cycle CO₂ emissions from nonrenewable technology j in units of tonnes of CO₂ equivalent per mwh, $CO_2_i^R$ is life-cycle CO₂ emissions from renewable technology i in units of tonnes of CO₂

equivalent per mwh, and $Generation_{i,j}$ is the amount of electricity generation from renewable electricity source i that substitutes for electricity from nonrenewable source j .

We also account for reductions in CO₂ emissions that occur through conservation. In most scenarios, electricity prices increase, and demand drops, thereby decreasing emissions of CO₂. The model tracks the change in generation from new, nonrenewable electricity sources, and formally, the calculation is

$$\sum_j CO2_j^{NR} \times Generationreduction_j ,$$

where $CO2_j^{NR}$ is the same emission factor described in the preceding equation, and $Generationreduction_j$ is the amount of electricity generation from nonrenewable source j reduced through conservation.

We estimate life-cycle CO₂ emission factors by combining data from EIA and literature values. In each AEO, EIA projects the carbon content of fossil fuels and the efficiencies of electricity generation technologies. We combine this information to estimate CO₂ emissions from burning fossil fuels to produce electricity. To estimate the full life-cycle emissions, we use estimates from the literature on the CO₂ emissions that occur in the remaining portions of the life cycle. In a recent literature survey, Meier et al. (2005) estimated emissions that occur in the fuel cycle (emissions from extraction and transportation of fossil fuels) and "fixed" emissions from power plant construction, materials, and decommissioning.

Tables A.26-A.30 display the data used to estimate emission factors.

Table A.26**Fuel-Cycle Carbon-Emission Data**

Fossil Fuel	Fuel Carbon Content (millions of tonnes per quad) ^a	Fuel-Extraction and -Delivery Emissions (tonnes of CO ₂ equivalent per GWh) ^b	Fixed Emissions (tonnes of CO ₂ equivalent per GWh) ^b
Natural gas	52.8	80.9	3.4
Coal	94.3	48.0	1.2

^a Source: EIA (2006a).

^b Source: Meier et al. (2005).

The Fuel Carbon Content column shows EIA's assumed values for the carbon content of natural gas and coal consumed in the electricity sector. These values are later converted in emission rates for specific power plants using the heat rates for fossil fuel power plants. The Fuel-Extraction and -Delivery Emissions column shows the estimate of emissions that occur while extracting and transporting coal and natural gas to a power plant. Natural gas actually has a higher emission rate due to the higher global warming potential of methane. The majority of the emissions in this portion of the life cycle come from leaking methane into the atmosphere (Meier et al., 2005). The Fixed Emissions column shows the emissions that occur during construction of the plant, building the materials, and decommissioning, under the assumption of a 30-year operating life.

Table A.27**Heat Rates for New Power Plants**

Generation Technology	Heat Rate (BTUs/kwh)
Pulverized coal	8,600
Advanced coal (IGCC)	7,200
Advanced combined cycle gas	6,333
Conventional combined cycle gas	6,800
Advanced combustion turbine	8,550
Conventional combustion turbine	10,450

Table A.27 shows EIA's assumptions about fossil fuel power plant heat rates. This information is used to estimate the life-cycle emissions from electricity generation in each plant, which are shown in

Table A.21. We display the rate for the three portions of the life cycle and the total in similar units of tonnes of CO₂ equivalent per mwh.

Table A.28

Life-Cycle CO₂ Emission Rates for Fossil-Fuel Plants

Generation Technology	Emission Rate (tonnes of CO ₂ equivalent per mwh)			
	Generation	Fuel Cycle	Fixed	Total
Pulverized coal	0.81	0.048	0.001	0.86
Advanced coal (IGCC)	0.68	0.048	0.001	0.73
Advanced combined cycle gas	0.33	0.081	0.003	0.42
Conventional combined cycle gas	0.36	0.081	0.003	0.44
Advanced combustion turbine	0.45	0.081	0.003	0.54
Conventional combustion turbine	0.55	0.081	0.003	0.64

Meier et al. (2005) also reported emission factors for the remaining technologies considered in this study.

Table A.29

Life-Cycle CO₂ Emissions for Renewable and Nuclear Generation

Generation Technology	Life-Cycle Emissions (tonnes of CO ₂ equivalent per mwh)
Biomass	0.046
Geothermal	0.015
Cofiring	0.046
Wind	0.014
Solar thermal	0.039
Nuclear	0.017

The emission rates in Tables A.27 and A.28 are used to calculate the difference between emissions from the renewable and nonrenewable sources. The model tracks how renewable electricity substitutes for nonrenewable generation, and we multiply the amount of generation substituted by the difference in emission rates.

Biofuels

The CO₂ calculation for biofuels follows the same format as that for the electricity market. We estimate the change in CO₂ emissions for each biofuel and the nonrenewable fuel substitute. We then multiply the amount of biofuels produced by the difference in emissions. We also estimate emissions saved from conservation by multiplying the reduction in gasoline and diesel by their life-cycle emissions.

Our estimates of life-cycle fuel emissions come from two recent studies. Farrell et al. (2006) estimated the life-cycle emissions from corn-based and cellulosic ethanol. Hill et al. (2006) estimated life-cycle emissions from biodiesel. Due to limited information in the literature, we have assumed that fuels derived via the FT or MTG method will have similar life-cycle emissions to those from cellulosic ethanol. Our estimates do not reflect the findings of two new studies suggesting that biomass utilization can cause net CO₂ emissions to increase after accounting for land use conversion that occurs directly or indirectly as new land is cleared to grow crops that were displaced for biofuels (Fargione et al., 2008; Searchinger et al., 2008). These studies show that the actual net CO₂ impacts of biofuels are highly sensitive to how they are produced. In light of these new studies, the values we calculate should be considered as upper bounds for emission reductions.

Table A.30

Transportation Fuel CO₂ Emission Rates

Biofuel	CO ₂ Emissions (g of CO ₂ equivalent per megajoule [MJ])	Reference Emissions (g of CO ₂ equivalent per MJ)	Change in CO ₂ (g of CO ₂ equivalent per MJ)	Change in CO ₂ (millions of tonnes of CO ₂ per quad of biofuel)
Cellulosic ethanol	11	94	-83	-87.6
FT gasoline	11	94	-83	-87.6
FT diesel	11	82.3	-71.3	-72.2
Biodiesel	49	82.3	-33.3	-35.1

Sources: Farrell et al. (2005), Hill et al. (2006).

Table A.30 shows life-cycle emissions from each biofuel in units of grams of CO₂ equivalent per MJ of energy. The reference fuel for

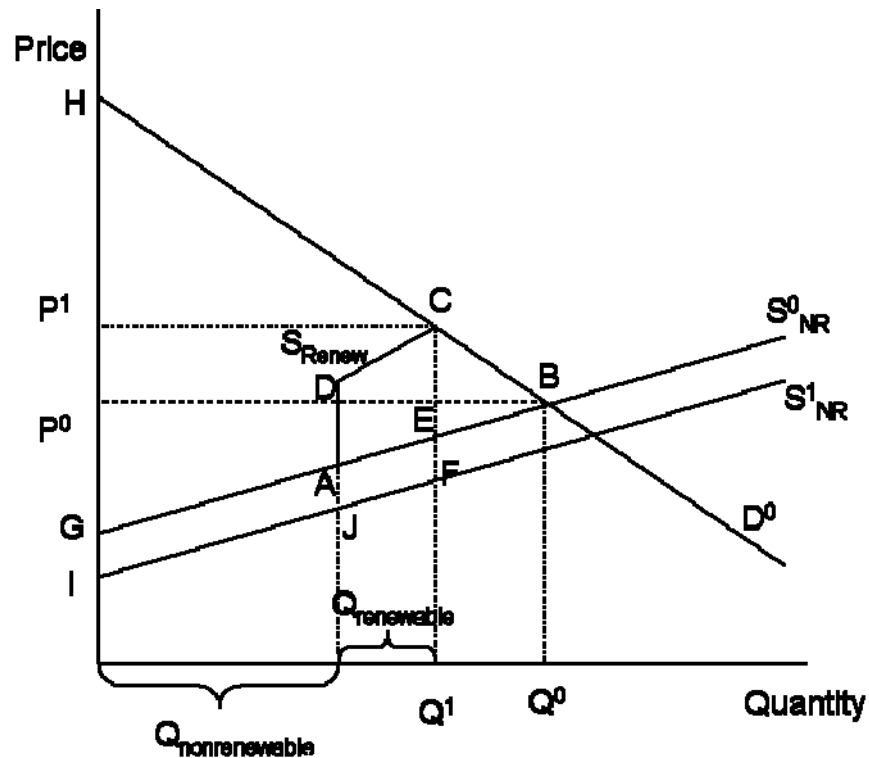
cellulosic ethanol and FT gasoline is conventional gasoline, with life-cycle emissions reported at 94 g CO₂ equivalent per MJ (Farrell et al., 2006). The reference fuel for FT diesel and biodiesel is a conventional low sulfur diesel, with life-cycle emissions reported at 82.3 g CO₂ equivalent per MJ (Hill et al., 2006). The final two columns report the changes in CO₂ equivalent emissions by substituting biofuels. The transportation market portion of the model calculates the quads of each biofuel produced and quads of gasoline and diesel reduced through conservation. These quantities are multiplied by the values in the last column to estimate the change in CO₂ emissions.

CALCULATION OF CONSUMER AND PRODUCER SURPLUS

Calculating the change in consumer and producer surplus electricity and motor vehicle fuels markets involves estimating the deadweight losses discussed in Chapter 2 and the incremental resource costs of renewable energy. The policy also affects social welfare in the markets for feedstocks (oil, natural gas, coal, and corn) in non-electricity and -fuels markets. Finally, the policy reduces U.S. spending on oil imports, which is a surplus gain for U.S. consumers. The models estimate all of these effects and I describe the methods below. **Figure A.5** is reproduced from Chapter 2 and illustrates the calculations used to estimate the deadweight losses and incremental resource costs in the electricity and motor vehicle fuels markets.

Figure A.5

Illustration of Surplus Change Calculations



The calculations are most straightforward in the motor vehicle transportation fuels market and I will first describe these calculations followed by the electricity market. As discussed in Chapter 2, the total welfare loss for motor vehicle fuels consumers can be decomposed into the incremental resource costs of renewables, given by quadrilateral AECD, and the deadweight losses caused by higher fuel prices, given by the triangle EBC. The consumer surplus portion of the deadweight losses is the easiest component to calculate. This portion is $1/2(Q^0 - Q^1) \times (P^1 - P^0)$. The producer surplus portion of the deadweight loss requires an estimate of the decrease in fuel prices due to the change in consumption from Q^0 to Q^1 . The model estimates the change in oil prices for the entire change in oil consumption, which includes the conservation effect from higher prices and substitution of biofuels for fossil fuels. I assume that the change in prices along this range of the supply curve is linear and use the model results to calculate the

slope of the supply curve. With this information, I can estimate the loss of producer surplus in the deadweight loss triangle.

The second component of the welfare loss, the incremental resource costs from renewables, involves summing the area under the renewable energy supply curve and then adjusting for the change in oil prices along $Q_{\text{renewable}}$. Again, I use the linear estimate of the change in oil prices for a change in consumption to adjust the incremental costs. With these calculations, I can estimate both components of the welfare loss relating to motor fuel consumption.

Three additional effects enter into the welfare calculations in this market. Lower oil prices increase oil consumption outside of the motor vehicle transportation fuels market and the model estimates the consumer surplus gain for this increased consumption. Note, this effect is separate from the surplus transfer from lower prices paid on inframarginal consumption. I calculate this effect also, which is described later. A second effect is decreased spending on oil imports. The policy lowers the world oil price and decreases U.S. consumer spending on oil imports; this is a surplus gain for U.S. consumers. The oil market model estimates U.S. oil imports and I count the change in these expenditures in the total welfare change. The final effect in the fuels market, under the unconstrained ethanol strategies, is the deadweight loss from lower corn consumption for non-ethanol corn consumers. Increasing corn ethanol production raises corn prices and non-ethanol consumers will decrease their consumption in response. I estimate an initial non-ethanol corn demand, price elasticity of demand, and corn price increase based on results in EIA (2007c). I can then calculate the change in non-ethanol corn demand and resulting deadweight loss from these values.

The calculations for the electricity market follow a similar process. The easiest component to estimate is the consumer surplus portion of the deadweight loss. I follow the same steps outlined above for motor vehicle fuels to make this calculation. The more complicated step is estimating the change in producer surplus as electricity consumption decreases. For this estimate, I calculate how average electricity prices decline for the change in electricity consumption from the conservation effect (the change in consumption from higher

electricity prices). The model estimates the change in natural gas and coal demand based on both the electricity conservation from higher electricity prices and the substitution of renewable electricity. The electricity model calculates which power plant production is displaced by the initial change in consumption from the conservation effect, and the change in natural gas and coal demand from this initial change. I then estimate the change in coal and natural gas prices using linear interpolation. The model calculates the total change in coal and natural gas prices from the total change in demand, including both the conservation and substitution effects. I estimate the change in coal and natural gas prices from only the conservation effect using linear interpolation of the total effect. The change in average electricity prices then is the total savings from lower natural gas and coal expenditures divided by the change in consumption.

The next component of the welfare change estimate is the total incremental resource costs of renewable electricity substitution. The model explicitly calculates these costs while calculating the incremental costs of substitution. Each renewable energy technology is assumed to substitute for electricity from fossil fuel plants. By multiplying the incremental costs of substituting renewables by the amount of electricity produced in each step in the curve, I calculate the incremental resource costs for each step and then sum across each step to calculate the total amount.

A final component of the welfare change calculation in the electricity market is the increase in consumption for non-electricity natural gas consumers. As natural gas prices decline, non-electric sector consumption rises and the natural gas market module within the electricity model estimates this change in consumption. Non-electricity natural gas consumption comprises almost 70% of total demand in the U.S. so this is a non-trivial effect. In contrast, the electricity sector consumes nearly all the coal used in the U.S., so I've assumed this effect is negligible for non-electricity coal consumers.

As noted in Chapter 2, the diagram shown above assumes the fossil fuel tax pricing mechanism in the fuels market, primarily because this is the easiest case to illustrate and explain. In most of the results in the fuels market, I've used the revenue-neutral tax-and-subsidy

mechanism; the electricity market only uses average pricing. The major effects described above all remain the same with these different mechanisms; however, the magnitudes change. The revenue-neutral tax-and-subsidy pricing mechanism sets prices based on a weighted average of the petroleum-derived and renewable fuels. This mechanism lowers the price increase for a given set of cost assumptions and the resulting deadweight losses are smaller. However, the incremental resource costs of renewable energy substitution increase because refiners need to produce more renewable energy to reach 25%. The subsidy case amplifies this effect. Total energy consumption actually increases because oil prices decline relative to the initial equilibrium. Consumers and producers gain some surplus from higher consumption, but the incremental resource costs of renewable energy substitution increase markedly because refiners need to produce considerably more renewable energy under this mechanism. Note, I did not show results in this analysis using this pricing mechanism because Toman et al. (2008) showed this mechanism resulting in the most costly outcomes under scenarios with the highest renewable energy costs.

A final issue in the calculation of consumer surplus is the effect of increasing energy efficiency on energy demand. I model energy efficiency as a substitute for renewable energy in the energy supply, but improving auto efficiency reduces the operating cost of the vehicle and is expected to change consumer demand. In the fuels market, I account for this effect by calculating the consumer surplus change in terms of energy services provided instead of energy consumed. I use EIA's estimates of VMT that underlie the fuels consumption estimates and calculate the consumer surplus gain from additional VMT consumed with more efficient vehicles. In the electricity market, I take a different approach based on an assumption that demand for energy services will remain relatively constant as more efficient lighting and electrical appliances are used and the overall effect of the policy is a shift in electricity consumption for a given level of energy services.

SURPLUS TRANSFERS BETWEEN ENERGY CONSUMERS AND PRODUCERS

As the renewable energy requirement changes prices for oil, coal, natural gas, corn, and biomass, surplus transfers between consumers and producers for inframarginal consumption. As commodity prices rise, energy producers gain consumer surplus on this inframarginal consumption; and the opposite occurs when commodity prices decline. One difference occurs for imports of oil. A decrease in spending for oil imports is a welfare gain for society and U.S. consumer surplus increases.

The models used in this analysis estimate the change in commodity prices as demand for renewable energy increases prices of corn and biomass and decreases prices of fossil fuels. The demand and supply models describing the markets for each of these commodities are described in earlier sections of the Appendix.

INCREMENTAL COSTS OF CO₂ REDUCTION AND LAND CONVERSION

Two additional measures calculated in this analysis are the incremental costs of CO₂ reduction and land use conversion. The incremental costs are the difference between renewable and nonrenewable costs at the 25 percent requirement level per unit of CO₂ reduction. It is important to note that this calculation is done for the renewable resource at the margin and represents the additional costs of reducing CO₂ by producing another gallon or kwh of renewable energy. The model estimates the cost difference between the two energy sources and divides by the relative difference in CO₂ emissions. The earlier section on calculating net CO₂ impacts describes the estimates of emissions differences.

For land conversion, I estimate the amount of biomass consumed from lands converted to energy crop production. This is the amount of biomass demand beyond the low-cost supplies. I assume an average yield of 7 tons of biomass per acre of land (Graham and Walsh, 1999). The future productivity of lands devoted to energy crop production is another large uncertainty. If average yields are higher, then the amount of land use conversion declines. The converse is true if average yields are lower.

EXPLORATORY MODELING ANALYSIS

Exploratory modeling is used to identify the key factors affecting the expenditure and CO₂ impacts of the renewables requirements. **Table A.31** summarizes the uncertain input parameters in our simulation model and the range of values we have assumed for each.

Table A.31

Uncertain Parameters Used in Experimental Design

	Value		
	Low	High	Initial
Electricity			
Wind capital cost change (% change)	-40	0	\$0.058 per kwh
Wind cost escalation factor (% change)	-50	50	0, 20, 50, 100, 200 \$0.041 per kwh
Biomass cost change (%)	-20	20	(excludes feedstock)
Geothermal escalation factor (% change)	-25%	25%	\$0.05, \$0.075, \$0.10, \$0.15, \$0.20, \$0.25, \$0.35 per kwh
Natural gas supply elasticity	0.2	0.6	—
Coal supply elasticity	0.7	1.3	—
Electricity demand elasticity	-0.2	-0.6	—
Wind capacity credit	0	0.4	—
Solar thermal cost (% change)	-30	30	\$0.135 per kwh
Solar thermal quantity (% change)	-30	30	—
Electricity efficiency initial cost (cents/kwh)	3	5	0%, 0%-25%, 75%-125%, 150%-200%
Electricity efficiency escalation factors	0	1	150%-200%
Electricity efficiency total potential	10%	15%	
Fuels			
Biofuel production cost (\$ per unit of input)	67	134	—
Low-cost biomass supply (millions of tons)	450	1,000	—
Feedstock supply distribution	EIA	UT	—
Biomass backstop price (\$ per ton)	90	200	—
Biofuel yield (gallons per ton)	80	100	—
Oil supply elasticity	0.2	0.6	—
Transportation demand elasticity	-0.2	-0.8	—
Shift in oil supply curve (% change)	-10	10	\$48 per barrel
Electricity coproduct (kwh per gallon)	0	2	—
Fuels efficiency initial cost (\$ per gallon)	2	4.85	
Fuels efficiency escalation factors	0	1	0%, 0%-50%, 80%-100%
Fuels efficiency total potential	10%	12.5%	
Initial corn price (\$ per bushel)	1.50	4	
Corn ethanol yield (gallons per bushel)	2.5	3	
Corn ethanol non-feedstock costs (\$/gallon)	0.1	0.55	

Where applicable, Table A.24 provides the initial values drawn from documentation of EIA's 2006 AEO reference case, which become a starting point for the uncertainty analysis. We use the ranges between the low and high values to generate a sample of possible future scenarios and run the model using these parameter values to calculate the impacts on expenditures and CO₂ reductions. For most electricity technology costs, we use EIA's 2006 AEO estimate as a starting point and DOE program goals as a lower bound for potential cost reductions. For technologies that are still under development today, we include potential for higher costs to allow for cost escalation over EIA's assumptions.

The first set of variables applies to the electricity market:

- **Wind capital cost change** varies the capital cost of wind that adjusts the y-intercept of the cost curve for wind
- **Wind cost escalation factor** varies the size of the cost steps for the wind supply curve
- **Biomass cost change** varies the nonfeedstock costs for dedicated biomass power plants
- **Geothermal escalation factor** varies the cost steps in the geothermal supply curve. The initial cost step remains fixed, and the additional steps either decrease or increase relative to the initial level.
- **Natural gas and coal supply elasticities** vary the supply elasticities in the supply models used for these resources. **Electricity demand elasticity** varies the price elasticity of demand used in the electricity demand function.
- **Wind capacity credit** varies the credit that wind power receives in displacing capital costs of firm power resources.
- **Solar thermal cost** varies the LCOE for solar thermal power.
- **Solar thermal quantity** varies the available capacity for solar thermal power.
- **Electricity efficiency initial cost** varies the costs of efficiency measures on the initial cost step.

- Electricity efficiency escalation factors scales the cost increases from the minimum to maximum values (0=min,1=max)
- **Electricity efficiency total potential** varies to the total amount of potential electricity saved through efficiency.

The next set of factors affects the motor vehicle transportation-fuel market:

- **Biofuel production cost** varies nonfeedstock conversion costs for biofuels.
- **Low-cost biomass supply** varies total biomass feedstock supply from waste and marginal lands available at a cost of less than \$90 per ton.
- **Feedstock supply distribution** varies the relative distribution of biomass in the different cost steps of the supply curve. The variable ranges from 0, which represents EIA's cost curve with more biomass in the high-cost portions, to 1, which represents the distribution of UT's supply curve with more biomass in the lower-cost steps.
- **Biomass backstop price** varies the cost of supplying biomass from converted agriculture and pasture lands.
- **Biofuel yield** varies the yield of biofuel gallons per ton of feedstock.
- **Oil supply elasticity** varies elasticity of supply in the world oil market model.
- **Transportation demand elasticity** varies the price elasticity of demand used in the function for transportation demand.
- **Shift in oil supply curve** varies the projected world oil price.
- **Electricity coproduct** varies the amount of electricity exported to the grid per gallon of biofuels produced.
- **Fuels efficiency initial cost** varies the initial cost of automobile efficiency measures and is used to construct the marginal cost curves.
- Fuels efficiency escalation factors scales the cost increase factors from the minimum to maximum values (0=min%,1=max%).
- **Fuels efficiency total potential** varies to the total amount of potential electricity saved through efficiency.

- **Initial corn price** varies the corn price used as feedstock in corn ethanol for the initial increment of supply beyond the baseline level.
- **Corn ethanol yield** varies the yield of ethanol from corn.
- **Corn ethanol non-feedstock cost** varies the non-feedstock costs for corn-based ethanol.

THRESHOLDS FOR LOW-COST AND HIGH-COST OUTCOMES USED IN UNCERTAINTY ANALYSIS

In the analysis in Chapter 3 and 4, I define thresholds for low-cost and high-cost outcomes as regions that would influence a decision maker's choice about the policy requirement. With a low-cost outcome, the policy achieves large benefits at low cost and is broadly supported by the public. High-cost outcomes are the opposite situation. The policy has high costs relative to the benefits and the public is generally opposed to the costs. I first define these thresholds using the damage estimates from the literature from the social costs of carbon and oil dependency. I then make a second calculation using estimates of willingness-to-pay for renewable energy.

For the high-cost outcome threshold, I use \$50 per tonne C (\$14 per tonne CO₂e) as a high-end estimate for the social cost of carbon. Tol (2005) found this value as the mean value of all the estimates from the peer-reviewed literature in a survey of 28 studies that produced a total of 94 estimates. While this value is the mean, it represents a high-end estimate because the results were highly right-skewed. I selected this value as part of the high-cost threshold because the literature suggests that if the renewable energy requirement's costs exceed this value substantially then the policy's costs are likely exceed the benefits to society from reducing GHG emissions. The second component of the high-cost outcome is the social cost of oil dependency. The fuels model already calculates the social welfare benefit of reducing oil import expenditures (monopsony effect) and the second component I include in this calculation is the macroeconomic costs of oil dependency. For this

value, I use the recent update in Leiby (2007) that estimates this externality at \$4.68 per barrel of oil.

To calculate the final estimates per unit of energy, I assume 8.9 kg of CO₂ per gallon of gasoline and a carbon-intensity of 0.61 kg per kwh of electricity. These were the values assumed in Creyts et al. (2007). Using these carbon intensities and the assumed valuations, they translate into \$0.12 per gallon gasoline eq and 0.8 cents per kwh. The oil dependency portion of the estimate adds \$0.11 cents per gallon (none assumed for electricity). Summing these social costs results in estimates of 0.8 cents per kwh and \$0.23 per gallon of gasoline equivalent.

For the low-cost outcome threshold, I use the estimate of the social cost of carbon NHTSA recently used in its proposal to increase CAFÉ standards (NHTSA, 2008). They also based their analysis on Tol (2005), and used a value of \$25 per tonne C or \$7 per tonne CO₂ equivalent. For the macroeconomic cost of oil dependency, I use the low-end value in Leiby (2007). He estimated this social cost at \$2.18 per barrel of oil. Following the same methods I used above to calculate the high cost thresholds, the sum of these social costs translates into per unit costs of 0.4 cents per kwh and \$0.11 per gallon of gasoline equivalent.

I also estimate these thresholds using valuations of consumer willingness-to-pay for renewable energy. I define these thresholds based on survey results and hedonic analysis of green energy pricing in Roe et al. (2001). In this paper, Roe et al. conduct a survey asking respondents to choose between two potential electricity plans. One of the plans increases the share of renewable energy and decreases emissions of NO_x, SO₂, and CO₂. The survey randomly assigned different elements of the plans, such as prices and changes in emissions. They also collect demographic data on their respondents. Roe et al. combine the data from survey responses with a hedonic estimate of the premium consumers pay for green electricity programs offered by several utilities.

Because of the recognized tendency for survey respondents to overstate their actual willingness-to-pay in their survey responses, I base the estimates on the hedonic analysis results. The regression

results estimate that consumers are willing to pay an additional \$6.20 per year for each 1% of renewable energy. I set this value as the upper bound in a triangular distribution and a lower bound of \$0 per year. I assume that the mode of the distribution is 25% below the upper bound of \$6.20, and has a value of \$4.70 dollars a year. I assume a lower value because the green pricing programs are voluntary, and therefore their prices should reflect the WTP of the upper end of the distribution. The survey results from Roe et al. (2001) show a much greater range of WTP (\$0.11-\$14.22 per year per 1% increase) and I've been more conservative in the assumptions I've used to develop the thresholds.

With these assumptions, the median WTP is \$3.80 per year, which translates households spending an additional \$96 per year for a program with 25% renewable energy. Roe et al.'s analysis assumes consumers use 1000 kwh of electricity a month. Therefore, the median WTP estimate per unit of electricity is 0.8 cents per kwh. The 25th percentile WTP is \$2.70 per year, which translates into additional spending of about \$68 per year for 25% renewable energy. The cost per kwh is 0.5 per kwh. I convert these price estimates in units of electricity into units of gallons of gasoline equivalent and estimate the the median WTP for fuels is \$0.21 cents per gallon and the 25th percentile WTP is \$0.11 per gallon.