TECHNICAL REPORT

Impacts on U.S. Energy Expenditures and Greenhouse-Gas Emissions of Increasing Renewable-Energy Use

Appendix B

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Prepared for the Energy Future Coalition

RAND Environment, Energy, and Economic Development

A RAND INFRASTRUCTURE, SAFETY, AND ENVIRONMENT PROGRAM

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APPENDIX B

Detailed Model Results

In this appendix, we present detailed results for the statistical analysis of our model runs. We also present output from model runs using varying levels of the policy requirement.

We derived our sample of outcomes using a Latin hypercube sampling (LHS) method (Saltelli, Chan, and Scott, 2000). We used this method to generate 1,000 combinations of input parameters and applied them to the three fuel pricing mechanisms used in the model, which resulted in an initial set of 3,000 scenarios. We used the LHS method because of its efficiency in sampling across a multidimensional space. We then removed scenarios from our results in which the models do not converge. Our cost curves consist of step functions with discontinuities at the points at which the functions increase. In scenarios in which equilibrium occurs near the discontinuities, the results can fluctuate substantially between iterations—often by more than 50 percent—and we removed these scenarios from our database. In the end, we finished with a total of 2,582 scenarios. There did not seem to be any systematic pattern to the nonconvergent scenarios that would suggest that their exclusion biases our conclusions.

Our goal in sampling across the input space is to understand the range of possible outcomes and the key factors that are often associated with low-cost and high-cost outcomes. This analysis method does *not* characterize the most likely outcome under the 25x'25 requirement, and it does not attach any greater likelihood to some sets of parameters over others. We used this method because we believe that the uncertainties for several of the key variables, such as biomass-feedstock and biofuel conversion costs, make it difficult to meaningfully define quantitative probability distributions for these parameters, which is a fundamental component of traditional uncertainty analysis. Instead, we used the model to explore the range of possible combinations of input parameters and learn which factors are often associated with low-cost and high-cost outcomes in our sets of scenarios.

In this latter step of identifying key factors, we applied a statistical data-mining algorithm[1] to our database of model inputs and results. The algorithm finds the factors most frequently associated with the lowest and highest 10 percent of expenditure change outcomes. The actual expenditure change at these thresholds varies across the markets and pricing mechanisms. In Tables B.1 through B.6, we identify the thresholds in the lowest and highest 10 percent of expenditure impacts.

Tables B.1 through B.6 separate the results by the two outcomes for each pricing mechanism. Within each table, we show the key variables identified by the algorithm and the range of values leading to the outcome. The variables are listed in order of importance in being

[1] We use the Patient Rule Induction Method (PRIM), a data-mining algorithm developed by Friedman and Fisher (1999).

Table B.1
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Renewables-Subsidy Pricing, Lowest–10 Percent Expenditure Change (less than $56 billion)

Variable	Value
Low-cost biomass supply	> 788 million tons of feedstock
Biofuel conversion cost	< $102 per ton of feedstock
Biofuel conversion yield	> 89 gallons per ton of feedstock
Oil price change	> –8.0% change from EIA

NOTE: Density = 0.70. Coverage = 0.56.

Table B.2
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Renewables-Subsidy Pricing, Highest–10 Percent Expenditure Change (more than $160 billion)

Variable	Value
Biomass-backstop price	> $158 per ton of feedstock
Biofuel conversion yield	< 91 gallons per ton of feedstock
Biofuel conversion cost	> $87 per ton of feedstock
Low-cost biomass supply	< 910 million tons of feedstock
Oil price change	< 7.5% change from EIA

NOTE: Density = 0.61. Coverage = 0.71.

Table B.3
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Revenue-Neutral Tax-and-Subsidy Pricing: Lowest–10 Percent Expenditure Change (< $12.8 billion)

Variable	Value
Price elasticity of demand	< –0.69
Biofuel conversion cost	< $91 per ton of feedstock

NOTE: Density = 0.71. Coverage = 0.34.

Table B.4
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Revenue-Neutral Tax-and-Subsidy Pricing: Highest–10 Percent Expenditure Change (> $78 billion)

Variable	Value
Price elasticity of demand	> –0.42
Biomass-backstop price	> $154 per ton of feedstock
Low-cost biomass supply	< 750 million tons of feedstock
Biofuel conversion cost	> $73 per ton of feedstock

NOTE: Density = 0.86. Coverage = 0.64.

Table B.5
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Fossil-Fuel Tax Pricing: Lowest–10 Percent Expenditure Change (< –$120.3 billion)

Variable	Value
Price elasticity of demand	< –0.66
Low-cost biomass supply	< 813 million tons of feedstock
Biofuel conversion yield	< 94.5 gallons per ton of feedstock

NOTE: Density = 0.77. Coverage = 0.69.

Table B.6
Detailed Results for Motor-Vehicle Transportation–Fuel Market: Fossil-Fuel Tax Pricing: Highest–10 Percent Expenditure Change (> –$6.5 billion)

Variable	Value
Price elasticity of demand	> –0.27
Low-cost biomass supply	< 904 million tons of feedstock

NOTE: Density = 0.83. Coverage = 0.84.

associated with the result. We also display two metrics related to the parameter-sampling process: density and coverage. The *coverage* metric reports the proportion of total outcomes of interest captured by the set of variables identified. For example, if the 10 percent lowest–expenditure change outcomes consists of 100 scenarios, and the set of variables identified by the algorithm contains 65 of these scenarios, then the coverage is 0.65. *Density* refers to the proportion of points of interest out of the total number contained by the region defined by the variables. For this term, suppose that one set of variables identified in the algorithm contains a total of 100 scenarios and that 50 of those points were the outcome of interest. Then the density is 0.5.

The key factors identified in the analysis should be interpreted as indicating that most of the scenarios with this outcome had these factors in common. For example, in the lowest–10 percent expenditure change outcomes for the revenue-neutral pricing mechanism, we found that a price elasticity greater than 0.69 in absolute terms and a biofuel conversion cost of less than $91 per ton of biomass feedstock frequently were part of the parameter samples. One could also say that, when these conditions hold, the prospect of a low–expenditure change outcome increases. However, our analysis does not establish causality.

Our results show that the quantity of low-cost biomass supply, the biofuel conversion cost, biofuel conversion yield, and price elasticity of demand are consistently the most important factors observed in the expenditure change outcomes. In the subsidy-pricing scenarios, the algorithm also identified the oil price change variable as being an important factor, since this reflects the adjustment of the level of the world oil price to the pricing policy.

In general, the results show that a low-cost biomass supply quantity of about 700 million to 800 million tons is a kind of threshold in the revenue-neutral tax-and-subsidy scenarios and the subsidy-pricing scenarios. The threshold for biomass supply was more than 900 million tons in the subsidy scenarios. The analysis also identifies biofuel conversion costs of about $90 to $100 per ton biomass and conversion yields near 90 gallons per ton as key thresholds. Scenarios with costs below this point and greater yields were more frequently found also to have low-cost outcomes. Conversely, when costs were greater than this and yields lower, then high-cost outcomes were more frequently observed in the scenarios.

As points of reference, until recently, EIA used biomass supply curves with a maximum quantity of about 430 million tons. In its recent analysis of a 25x'25 policy, it included a high-yield supply curve with slightly more than 600 million tons of supply from wastes and energy crops grown on marginal lands. This excludes biomass supplies from forests. A recent estimate showed that forests could provide up to about 370 million tons of biomass (Perlack et al., 2005).

Our results suggest that low-cost biomass supply needs to reach the upper ranges of our assumed values to avoid cost increases resulting from feedstock scarcity, and these values are much greater than several recent estimates of supply. If low-cost supplies do not reach these levels, then the prospect is greater for a high–expenditure change outcome and significant land conversion.

For biofuel conversion costs, the DOE Biomass Program goal for cellulosic-ethanol costs translates into a conversion cost of $67 per ton of biomass. The upper end of our range has a cost of $134 per ton of biomass and reflects a scenario in which biofuel plants are about 25 percent more expensive than initial estimates, although we assume that cost reductions are achieved through learning as the industry gains experience and increases capacity. In this context, achieving $90 per ton of biomass represents significant progress toward the Biomass Program cost goal. It reflects a scenario in which a substantial amount of learning occurs and cost escalation in the initial plants is not severe.

For two of the price mechanisms—taxes on fossil fuels and revenue-neutral tax and subsidy—a final key factor is the price elasticity of demand for motor vehicle–transportation fuels. The price elasticity of demand reflects consumer responsiveness to price changes. As demand becomes more elastic (greater price elasticity in absolute terms), demand decreases are larger for a given price change, which has a moderating impact on expenditures. As demand is more inelastic (lower price elasticity in absolute terms), demand changes less for a given price change, and the impacts on expenditures are greater.

In the context of our analysis, as the price of motor fuels rises to reflect higher costs of biofuels under the two pricing policies mentioned, consumers decrease their fuel consumption by using alternatives (e.g., more-efficient cars, public transport) or by reducing their transportation demand (e.g., move closer to work, reduce discretionary travel). The literature shows that demand is less responsive in the short term than in the long term, because people have more time to adjust their behavior over the long term. Given the time frame for implementing this policy, consumers would have the ability to make long-term adjustments to higher fuel prices, which suggests that consumers may behave in the more elastic portion of the assumed range. We, nonetheless, consider a broad range of elasticities and find this to be an important variable affecting expenditure changes.

The scenario-discovery analysis shows a sharp difference in the price elasticity of demand observed in the low– and high–expenditure change scenarios. In the low–expenditure change outcomes, consumers behaved in the most elastic portion of the assumed range (greater than 0.65–0.7 in absolute value). The opposite was true for the high–expenditure change scenarios (price elasticity of less than 0.3–0.4 in absolute value). The ranges identified in these results are within the range of estimates for long-run price elasticities found in the literature.

In the subsidy-pricing mechanism, oil prices were an important factor. As oil prices increase, cost differences between biofuels and fossil fuels decrease and the expenditure impacts moderate. At lower oil prices, the expenditure impacts are greater. In the fuel model, we could vary oil prices by 10 percent in either direction from EIA's assumption. EIA's 2006 AEO projects 2025 oil prices at $48 per barrel. Our range then encompassed oil from $43 to $53 per barrel. In the low–expenditure change outcomes, oil prices remained above $44 per barrel.

The ranges on both of these results are broad, and, in interpreting these results, it is important to note that all of the conditions identified by the PRIM analysis must hold simultaneously and that the algorithm identifies variables in order of importance. The results show that low biofuel costs were correlated with the low–expenditure change scenarios, as long as oil prices were above the lowest portion of the range (nearing $40 per barrel). The converse occurred in the high–expenditure change scenarios. High biofuel costs were correlated with the high–expenditure change scenarios, as long as oil prices remained below the highest portion of the range (more than $50 per barrel). This finding does not imply that much higher oil prices (more than $80 per barrel) would automatically result in low–expenditure change outcomes. The illustrative scenario with high oil prices at the end of Chapter Three (see Table 3.2) shows that expenditure changes can decrease considerably (more than 50 percent) when assuming higher oil prices than those in the 2006 AEO reference case, but high–expenditure change outcomes are still possible if biomass feedstock and conversion costs are in the high-cost portion of the assumed range.

The results when using a fossil-fuel tax as the pricing mechanism are somewhat counterintuitive in the low–expenditure change outcomes. The key factors identified by the analysis generally lead to higher costs. However, in this case, these factors limit expenditure changes while increasing the amount of fuel tax revenues collected. Since we assume that these revenues are transferred back to the consumer, on net, the expenditure changes are large and negative. In the highest–expenditure change scenarios, the analysis found that inelastic demand and lower levels of low-cost biomass supply were key factors, which is consistent with the other cases.

Tables B.7 and B.8 show the analysis results for the electricity market. The tables follow the same format as Tables B.1 through B.6. In the electricity market, wind-power costs, price elasticity of demand, and biomass costs were significant factors associated with high– or low–expenditure change outcomes.

Biomass and wind costs are key factors because they are very influential in determining the incremental substitution costs in meeting the policy requirement. Wind power has the largest potential supply and is generally the marginal resource, which sets the incremental cost of meeting the policy. Bioelectricity, from both dedicated plants and co-firing facilities, is generally not at the margin but affects how much wind is needed to meet the policy requirement. In general, increasing the amount of bioelectricity directly reduces wind power. If the bioelectricity supply is large enough, then a lower-cost wind supply becomes the marginal resource.

Table B.7
Detailed Results for Electricity Market: Lowest–10 Percent Expenditure Change (< $10.25 billion)

Variable	Value
Wind capital cost (% change from EIA)	< –30
Wind escalation cost (% change from EIA)	< –16
Price elasticity of demand	< –0.25

NOTE: Density = 0.70. Coverage = 0.67.

Table B.8
Detailed Results for Electricity Market: Highest–10 Percent Expenditure Change (> $36.3 billion)

Variable	Value
Wind capital cost (% change from EIA)	> –21
Wind escalation cost (% change from EIA)	> –15
Price elasticity of demand	> –0.47
Biomass backstop price ($/ton of feedstock)	> 117
Low-cost biomass supply (millions of tons of feedstock)	< 950

NOTE: Density = 0.57. Coverage = 0.79.

Our wind supply curves use two factors. The capital cost determines the y-intercept of the curve, and the escalation factors affect how much costs grow as capacity increases. Both of these factors directly affect wind costs and thereby the incremental cost of meeting the policy requirement.

Consumer responsiveness (price elasticity of demand) is a third key factor. Under all of our scenarios, the costs of renewable electricity at 25 percent penetration exceed the costs of conventional sources. Therefore, electricity prices will rise to reflect the higher costs of renewables. Similar to the motor-fuel market, the price elasticity of demand determines how consumers adjust to higher prices and has important implications for expenditures. For a given price change, increasing the price elasticity of demand (in absolute terms) moderates the impact on expenditures.

The analysis shows that wind-power costs are the most important factors in both outcomes. EIA assumes that the levelized costs of wind power at the initial step of the cost curve are $0.058 per kWh with overnight capital costs of $1,150 per kW. In the low–expenditure change scenarios, baseline wind-power costs were 30 percent below EIA's cost assumptions. Furthermore, the cost escalation for lower-quality wind sites was less than 16 percent under EIA's assumptions. Finally, price elasticities remained outside of the most inelastic portion of the assumed range.

In the high–expenditure change scenarios, many scenarios exhibited some progress in wind-power costs; however, this progress was offset by high-cost biomass supply and limited price response by consumers. The biomass assumptions translate into costly biomass electricity that is generally uncompetitive with the other renewable. This increases the amount of wind power used to meet the requirement for development of low-quality, expensive sites. Finally, consumers were in the less elastic portion of the assumed range and less responsive to the price increases resulting from the policy requirement.

Overall, the analysis shows that achieving the 25 percent policy requirement in both electricity and motor fuels at low cost to electricity consumers will require significant progress in supplying a large and inexpensive feedstock supply. If this occurs and significant progress in wind-power technology occurs, then the policy requirement may have modest impacts on electricity expenditures. If it is not feasible to produce a large, low-cost biomass supply by 2025, even with some progress on wind-power technology, high–expenditure change impacts from the policy requirement can occur.

It is important to note that the range of expenditure changes in the electricity market is much smaller in both absolute and relative terms than that for the motor-fuel market. From this perspective, the 25 percent renewable-energy requirement could be seen as less risky in the electricity market than in the motor-vehicle transportation–fuel market. Another important insight from our analysis is that the joint policy requirement for renewable electricity and biofuels could significantly increase the cost of meeting the requirement in the electricity market, because the demand for biomass to produce biofuels increases the costs of supply for the electricity market.

Table B.9 shows model results in the motor-vehicle transportation–fuel market for different levels of the renewable-energy policy requirement. For these model runs, we set our parameter assumptions in the middle of their various ranges and used the revenue-neutral tax-and-subsidy pricing mechanism. Again, we did not choose this set of assumptions to reflect a judgment that this was a most likely scenario.

The first set of outputs shows the components of the expenditure change metric. The first line is the total consumer expenditures on motor vehicle–transportation fuels. The next line is the difference in model-predicted expenditures and the EIA AEO 2006 baseline. The third line gives the net change in government expenditures and taxes collected. Since this is the revenue-neutral case, the net change is zero. The next line shows consumer expenditure savings on nontransportation fuels (e.g., home heating, industrial oil use). The final line is the sum of the expenditure changes. In the results, expenditure changes grow as the requirement level increases, because more-expensive biofuels are produced to meet the requirement. At 25 percent, there is a considerable jump in the cost, which is caused largely by a significant jump in feedstock prices due to biomass scarcity.

The second set of outputs shows various measures of cost, market prices, quantities produced, and CO_2 emission changes. The first four outputs of this set show the retail costs of producing renewable and nonrenewable fuels. The pricing mechanism then translates these costs into a market price that consumers see at the pump. Two key measures are the biomass price and land conversion. The biomass price is the market-clearing price for biomass feedstock. Land conversion is the amount of land-use change required to meet total demand for feedstock. We assume that a certain amount of low-cost biomass is available from wastes and marginal lands and that any biomass demand in excess of that value is supplied by converting agricultural lands or pasturelands. The remaining outputs show measures relating to the types of biofuels produced, total motor vehicle–fuel consumption, and changes in world oil prices.

Table B.10 shows detailed outputs for the same scenarios in the electricity market. The first set of outputs shows the components of the expenditure metric. The change in renewable-electricity expenditures accounts for expenditures on the incremental costs of renewable electricity. The next output is the decrease in spending on fossil fuels due to the drop in coal and natural gas prices. Net electricity consumer expenditure change is the sum of the two previous components. Nonelectricity consumer expenditure changes account for drops in the price of natural gas sold to nonelectricity consumers. The final measure is net consumer expenditure change, which sums the changes in the electricity and nonelectricity markets.

The next set of measures shows total electricity demand, average prices, and CO_2 emissions. An important output reported here is the incremental cost of marginal renewable electricity. This is the incremental cost of renewable electricity at the unit that meets the policy requirement. Another interpretation of this measure is that it is the subsidy needed to induce the required level of renewable electricity. The results show a substantial increase in the incremental costs between 20 percent and 25 percent. This occurs because the amount of

Table B.9
Detailed Results in Motor-Vehicle Transportation–Fuel Market for Increasing Renewables Requirement Levels

	Requirement Level (%)		
Outputs	**15**	**20**	**25**
Total consumer fuel expenditures (billions of 2004 dollars)	500.1	515.6	542.5
Consumer fuel-expenditure change (billions of 2004 dollars)	9.5	25.0	51.9
Government net expenditure or tax collected (billions of 2004 dollars)	0.0	0.0	0.0
Nontransportation fuel-expenditure change (billions of 2004 dollars)	–1.3	–2.0	–2.8
Net consumer fuel-expenditure change (billions of 2004 dollars)	8.2	23.1	49.1
Retail gasoline cost (2004 dollars per gallon)	2.11	2.10	2.09
Retail diesel cost (2004 dollars per gallon)	2.05	2.04	2.03
Retail renewable-gasoline cost (2004 dollars per gallon)	3.03	3.78	4.56
Retail renewable-diesel cost (2004 dollars per gallon)	2.98	3.73	4.51
Gas-market price (2004 dollars per gallon)	2.21	2.34	2.55
Diesel-market price (2004 dollars per gallon)	2.20	2.42	2.76
Gasoline, ethanol, or FT gas consumed (quads)	21.3	20.7	19.8
Diesel, biodiesel, or FT diesel consumed (quads)	7.2	6.9	6.4
CO_2 avoided (millions of tonnes)	325.2	510.9	727.8
Percentage renewable fuels	15	20	25
Electricity co-product (billions of kWh)	31.6	43.6	53.7
Total biomass demand (millions of dry tons)	603.1	700.0	725.7
Biomass price (dollars per ton)	50	90	145
Land conversion (millions of acres)	0.0	0.0	5.1
Ethanol produced (billions of gallons)	31.0	38.4	44.5
Existing ethanol (billions of gallons)	11.7	11.7	11.7
New U.S. ethanol (billions of gallons)	19.3	26.7	0.1
FT gasoline (billions of gallons)	4.4	6.1	7.5
Biodiesel (millions of gallons)	250.0	400.0	400.0
FT diesel (billions of gallons)	7.9	10.9	13.4
Gasoline, ethanol, or FT gas consumed (quads)	21.3	20.7	19.8
Diesel, biodiesel, or FT diesel consumed (quads)	7.2	6.9	6.4
World oil price (dollars per barrel)	47.07	46.56	45.98
Oil price change (dollars per barrel)	–0.92	–1.43	–2.01
Change in U.S. oil demand (millions of barrels per day)	2.0	3.1	4.3
Nontransportation U.S. oil demand (millions of barrels per day)	7.5	7.6	7.6

Table B.9—Continued

	Requirement Level (%)		
Outputs	**15**	**20**	**25**
Nontransportation U.S. oil expenditure (billions of dollars)	129.4	128.7	127.9
Change in nontransportation U.S. oil expenditure (billions of dollars)	–1.3	–2.0	–2.8

Table B.10
Detailed Results in Electricity Market for Increasing Renewables Requirement Levels

	Requirement Level (%)		
Output	**15**	**20**	**25**
Total consumer electricity expenditures (billions of 2004 dollars)	371.2	389.7	417.5
Change in consumer electricity expenditures (billions of 2004 dollars)	6.6	28.8	59.4
Change in electric-utility fossil-fuel expenditures (billions of 2004 dollars)	–3.0	–6.9	–9.7
Net electricity consumer expenditure change (billions of 2004 dollars)	3.6	21.9	49.7
Nonelectricity consumer fossil-fuel expenditure change (billions of 2004 dollars)	–0.3	–4.6	–8.6
Net consumer expenditure change (billions of 2004 dollars)	3.3	17.3	41.2
Total generation (billions of kWh)	4,914.0	4,757.6	4,543.5
Average price (dollars per kWh)	0.076	0.082	0.092
Incremental cost of substituting renewable electricity (dollars per kWh)	0.225	0.580	0.884
CO_2 avoided (millions of tonnes)	205.5	462.0	764.7
Percentage renewable electricity	15	20	25
Hydroelectric (billions of kWh)	298.6	298.6	298.6
Co-firing (billions of kWh)	149.0	94.1	0.0
Biomass (billions of kWh)	153.0	120.3	53.7
Wind (billions of kWh)	65.3	337.9	683.0
Geothermal (billions of kWh)	71.6	100.6	100.6
Solar thermal (billions of kWh)	0.0	0.0	0.0
Nuclear displaced by renewables (billions of kWh)	19.0	0.0	0.0
Coal generation displaced by renewables (billions of kWh)	264.5	403.2	486.3
Natural gas generation displaced by renewables (billions of kWh)	11.6	94.0	185.3
Nuclear displaced by conservation (billions of kWh)	28.3	47.3	47.3
Coal generation displaced by conservation (billions of kWh)	0.0	0.0	95.8
Natural gas generation displaced by conservation (billions of kWh)	0.0	139.6	257.9
Electricity-utility natural gas demand (quads)	0.1	1.6	3.1
Electricity-utility coal demand (quads)	2.1	3.3	5.0
Change in electricity-utility natural gas price (2004 dollars per thousand thousand BTUs, or MMBTUs)	–0.3	–0.5	–0.9

Table B.10—Continued

	Requirement Level (%)		
Output	**15**	**20**	**25**
Change in electricity-utility coal price (2004 dollars per MMBTU)	−0.1	−0.2	−0.3
Nonelectric natural gas demand (quads)	18.6	19.1	19.7
Nonelectric natural gas price (2004 dollars per MMBTU)	7.5	7.0	6.6
Nonelectric natural gas expenditures (billions of 2004 dollars)	138.7	134.4	130.4
Change in nonelectric natural gas expenditures (billions of 2004 dollars)	−0.3	−4.6	−8.6

biomass available to the electricity sector drops considerably and forces more-expensive renewable electricity into the system to meet the requirement. This effect is seen in the generation results in the next set of outputs. At 25 percent, biomass and co-firing generation declines substantially and is made up by a substantial increase in wind power. The final set of outputs shows the changes in nonrenewable generation and effects on the markets for coal and natural gas.