Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs

FY 2005 – FY 2050

Nonrenewable Energy Consumption, 1980-2000, and Projections to 2050: Baseline and Portfolio Cases

Prepared for the

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Office of Energy Efficiency and Renewable Energy Programs

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EXECUTIVE SUMMARY

The Office of Energy Efficiency and Renewable Energy (EERE) of the U.S. Department of Energy (DOE) leads the Federal Government's efforts to provide reliable, affordable, and environmentally sound energy for America, through its 11 research, development, demonstration, and deployment (RDD&D) programs. EERE invests in high-risk, high-value research and development (R&D) that, conducted in partnership with the private sector and other government agencies, accelerates the development and facilitates the deployment of advanced clean energy technologies and practices. EERE designs its RDD&D activities to improve the Nation's readiness for addressing future energy needs.

This document summarizes the results of the benefits analysis of EERE's programs, as described in the FY 2005 Budget Request. EERE has adopted a benefits framework developed by the National Research Council (NRC)[1] to represent the various types of benefits resulting from the energy efficiency technology improvements and renewable energy technology development prompted by EERE programs. Specifically, EERE's benefits analysis focuses on three main categories of energy-linked benefits—economic, environmental, and security. The specific measures or metrics of these benefits estimated for FY 2005 are identified in **Table ES.1**. These metrics are not a complete representation of the benefits or market roles of efficiency and renewable technologies, but provide an indication of the range of benefits provided. EERE has taken steps to more fully represent the NRC framework, including two key improvements to the FY 2005 analysis—adding an electricity security metric and extending the analysis through the year 2050. EERE will be implementing additional portions of the framework in the future.

Table ES.1. EERE FY 2005 Benefits Metrics

Primary Outcome	
Energy displaced	• Reductions in nonrenewable energy consumption
Resulting Benefits	
Economic	• Reductions in consumer energy expenditures (NEMS-GPRA05) • Reductions in energy-system costs (MARKAL-GPRA05)
Environmental	• Reductions in carbon dioxide emissions
Security	• Reductions in oil consumption • Reductions in natural gas consumption • Avoided additions to central conventional power[2]

Table ES.2 shows the estimated energy displaced and resulting benefits to the Nation of realizing the EERE program goals associated with the FY 2005 budget request. These impacts are the benefits expected in the reported year—that is, the benefits are annual, not cumulative. Under a business-as-usual energy future, realization of these goals and the associated projected market outcomes would:

[1] *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000*, National Research Council (2001). The NRC is the principal operating agency of the National Academy of Sciences (NAS) and the National Academy of Engineering (NAE), providing services to the government, the public, and the scientific and engineering communities.

[2] Central conventional power includes centrally located fossil, nuclear, combined cycle, combustion turbine/diesel, and pumped storage. It does not include distributed power and renewable power (central or distributed).

- Reduce the expected increase in U.S. energy demand by 31% in 2025 and 60% in 2050, resulting in a leveling off of nonrenewable energy consumption starting in 2025. (**Figure ES.1**)
- Reduce the expected increase in U.S. consumer energy expenditures by 37% in 2025. (**Figure ES.2**)
- Reduce the expected increase in U.S. energy system costs by 6% in 2050. (**Figure ES.3**)
- Reduce the expected increase in annual U.S. carbon dioxide emissions by 35% in 2025 and 54% in 2050. (**Figure ES.4.**)
- Reduce the expected increase in U.S. oil consumption (most of which is expected to originate from outside the United States) by 26% in 2025 and 84% in 2050, resulting in declining oil consumption after 2025. (**Figure ES.5**)
- Reduce the expected increase in U.S. natural gas consumption, much of which is expected to originate outside the United States, by 18% in 2025 and 21% in 2050. (**Figure ES.6**)
- Reduce the need for additions to central conventional power by 64% in 2025. (**Figure ES.7**)

Table ES.2. Summary of EERE Integrated Portfolio Benefits for FY 2005 Budget Request[3,4]

EERE Midterm Benefits	**2010**	**2015**	**2020**	**2025**
Energy Displaced				
• Nonrenewable energy savings (quadrillion Btu/yr)	1.8	3.6	6.9	10.4
Economic				
• Energy-expenditure savings (billion 2001 dollars/yr)*	27	51	90	134
Environment				
• Carbon dioxide emission reductions (mmtc equivalent/yr)	35	74	139	213
Security				
• Oil savings (mbpd)	0.2	0.5	1.1	2.1
• Natural gas savings (quadrillion Btu/yr)	0.7	1.0	1.9	1.9
• Avoided additions to central conventional power (gigawatts)[5]	24	66	105	157

EERE Long-Term Benefits	**2020**	**2030**	**2040**	**2050**
Energy Displaced				
• Nonrenewable energy savings (quadrillion Btu/yr)	7.4	16.5	25.8	32.3
Economic				
• Energy-system cost savings (billion 2001 dollars/yr)*	42	88	171	236
Environment				
• Carbon dioxide emission reductions (mmtc equivalent/yr)	145	334	471	593
Security				
• Oil savings (mbpd)	1.0	4.7	9.0	11.6
• Natural gas savings (quadrillion Btu/yr)	2.6	2.8	5.2	4.5

* Midterm energy-expenditure savings only include reductions in consumer energy bills, while long-term energy-system cost savings also include the incremental cost of the advanced energy technology purchased by the consumer.

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[3] Estimates reflect the benefits associated with program activities from FY 2005 to the benefit year, or to program completion (whichever is nearer), and are based on program goals developed in alignment with assumptions in the president's budget. Midterm program benefits were estimated using the NEMS-GPRA05 model, based on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and using the EIA's *Annual Energy Outlook 2003* (*AEO2003*) Reference Case. Long-term benefits were estimated using the MARKAL-GPRA05 model developed by Brookhaven National Laboratory. Results can differ among models due to structural differences. The models used in this analysis estimate economic benefits in different ways, with MARKAL reflecting the cost of additional investments required to achieve reductions in energy bills.

[4] For some metrics, the benefits estimated by MARKAL-GPRA05 do not align well with those reported by NEMS-GPRA05. Every attempt is made in the integrated modeling to use consistent baselines, input data and assumptions in both models to produce consistent results. However, NEMS and MARKAL are in some respects fundamentally different models (see Boxes 4.1 and 5.1). Discrepancies in the estimated benefits often differ simply because of these model differences.

[5] Small final changes in these estimates were not reflected in the FY 2005 Budget Request.

EERE develops these benefits projections annually to help meet the requirements of the Government Performance and Results Act (GPRA) of 1993 and the President's Management Agenda (PMA). GPRA requires Federal Government agencies to develop and report on output and outcome measures for each program. This analysis helps meet GPRA requirements by identifying the potential outcomes and benefits of realizing EERE program goals (outputs). The benefits estimates do not reflect the risk of realizing these goals, which is being addressed separately.[6]

The reported benefits reflect only the net annual improvement from 2005 to 2050 of program activities included in EERE's FY 2005 Budget Request (including subsequent-year funding) and do not include the benefits from past work. The benefits estimates assume continued funding for program activities consistent with multiyear program plans.[7] By basing estimated benefits on budget levels, the analysis addresses the performance-budget integration goal of the PMA. This analysis also provides the benefits called for in the R&D Investment Criteria, developed by the Office of Management and Budget (OMB) as part of the PMA.

EERE uses two energy-economy models—NEMS-GPRA05 and MARKAL-GPRA05—to estimate the impacts of EERE programs on energy markets. The NEMS-GPRA05 model is a modified version of the National Energy Modeling System (NEMS), the midterm energy model used by the Department of Energy's Energy Information Administration (EIA). The MARKAL-GPRA05 model is a modified version of the MARKet ALlocation (MARKAL) model developed by Brookhaven National Laboratory and used by numerous countries worldwide. EERE uses NEMS-GPRA05 to estimate the midterm benefits of its programs and MARKAL-GPRA05 to estimate the long-term benefits of its programs. Descriptions of these models are provided in **Chapters 4 and 5**.

EERE uses a three-step process to estimate benefits across its portfolio:
(1) Establishment of the Baseline Case and guidance
(2) Determination of program and market inputs
(3) Assessment of program and portfolio benefits.

In **Step 1**, a Baseline Case and standard methodological approach (guidance) are developed to improve the consistency of estimates across EERE programs. The Baseline Case provides a representation of business-as-usual future energy markets without the effect of EERE programs. It also provides a consistent set of assumptions about future energy prices, conversion factors, economic growth, and other external factors, against which to analyze the impacts of EERE programs. To develop the Baseline Case through 2025, EIA's *Annual Energy Outlook 2003* (*AEO2003*) Reference Case forecast is modified to remove any identifiable effects of EERE programs already included in the forecast. This is done for both the NEMS-GPRA05 model and the MARKAL-GPRA05 model.[8]

For the period after 2025, other credible sources are used to compile a set of economic and

[6] A standard approach to risk assessment is being developed for EERE's multiyear program plans.
[7] Funding levels may increase, decrease, or remain constant, depending on the program. See Appendices B through M for information on individual multiyear program plans.
[8] Slight differences in the NEMS-GPRA05 and MARKAL-GPRA05 baselines may occur from the differences inherent in the two models.

technical assumptions for MARKAL-GPRA05.[9] A summary of the Baseline Case results is included in **Appendix A**. EERE also specifies common methodological approaches (guidance) used in developing benefits estimates. This guidance identifies common definitions, the basis for assessing benefits, data requirements, etc. An overview is provided in **Chapter 2**.

In **Step 2**, analysts from throughout EERE characterize the results of the EERE programs in a format suitable for analysis within the NEMS and MARKAL integrated-modeling frameworks. For technology R&D programs, this usually requires expressing program outputs in terms of the cost and performance of a new (or improved) product, which will compete against an existing technology in the baseline. For deployment programs (*e.g.*, information dissemination, or codes and standards), analysts develop approaches to characterizing outputs on a case-by-case-basis using alternative modeling techniques such as altering discount rates or fixing market penetration (in the case of minimum efficiency standards). In many cases, the NEMS and MARKAL frameworks are not suitable for directly analyzing programmatic activities; as a result, "off-line" analyses are conducted. The market analyses and off-line estimates used in the integrated modeling framework are documented in **Appendices B through M.**

In **Step 3**, the program- and market-specific information from **Step 2** is incorporated into NEMS-GPRA05 and MARKAL-GPRA05. Modeling all the programs together accounts for market feedbacks and interactions that can change the ultimate level of energy savings associated with realizing each program's goals. EERE adjusts off-line estimates to account for areas of overlapping program impacts. This downward revision is based on how much of the overlap or integration was captured by the off-line analysis. The benefits analysis team, based on its expert judgment, determines the amount of revision. The resulting benefits estimates of individual program analyses are listed by program, along with FY 2005 program budgets, in **Table ES.3** below.

Analysts also run NEMS-GPRA05 and MARKAL-GPRA05 with all programs simultaneously represented, in order to derive estimates of the benefits of the overall EERE portfolio. This portfolio analysis accounts for interactions among EERE's programs, and tends to report reduced benefits compared to the sum of the individual programs. These fully integrated results are listed in **Table ES.2** and displayed in the graphs in this **Executive Summary**. Specific details on the representation of program outputs in NEMS-GPRA05 and the underlying program analysis and documentation are provided in **Chapter 4** of this report. Representation of the program outputs in MARKAL-GPRA05 is provided in **Chapter 5**.

EERE is pursuing a number of improvements to its benefits analysis. Important changes planned for analysis of the benefits of the FY 2006 budget request include:

- Developing alternative scenarios that reflect potential options facing the Nation in the future (*e.g.*, higher fossil fuel prices, a carbon-constrained world).
- Greater streamlining and consistency in the development of program-level benefits estimates.

[9] For instance, the primary economic drivers of Gross Domestic Product (GDP) and population are based on the real GDP growth rate from the Congressional Budget Office's Long-Term Budget Outlook and population growth rates from the Social Security Administration's *2002 Annual Report* to the board of trustees.

In addition, EERE is developing methods for linking estimates of benefits from both past and future program efforts into the overarching NRC benefits framework noted above. Finally, EERE is developing a more systematic way of representing program and technology risk. Although not part of this benefits analysis *per se*, information on risk is recognized as an important component in the application of benefits information to portfolio management.

Table ES.3. U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy (EERE): FY 2005 Funding Summary and Selected 2025 and 2050 Benefits by Program[10]

Program	FY 2005 Request (thousands $)	Nonrenewable Energy Displaced (quads/yr)		Energy Expenditure Savings (billions 2001$/yr)		Energy System Cost Savings (billions 2001$/yr)		Carbon Dioxide Emissions Reductions (million Mtce/yr)		Oil-Use Reductions (mbpd)	
		2025	2050	2025	2050	2025	2050	2025	2050	2025	2050
Biomass	81,276	0.2	1.2	1.7	N/A	N/A	-0.3	2.7	22.6	0.0	0.4
Building Technologies	58,284	2.0	2.8	26.6	N/A	N/A	45.3	42.5	49.8	0.1	0.2
Distributed Energy Resources	53,080	0.4	1.2	10.6	N/A	N/A	6.2	15.2	30.1	0.0	0.0
Federal Energy Management	19,867	0.1	0.2	0.6	N/A	N/A	3.0	1.5	4.0	0.0	0.0
Geothermal Technologies	25,800	0.3	2.1	1.5	N/A	N/A	8.9	6.7	49.9	0.0	0.0
Hydrogen, Fuel Cells, and Infrastructure Technologies	172,825	0.5	9.2	5.2	N/A	N/A	78.6	11.8	138.3	0.4	6.2
Industrial Technologies	58,102	2.0	2.2	15.8	N/A	N/A	15.0	41.4	40.8	0.2	0.1
Solar Energy Technologies	80,333	0.4	1.6	4.9	N/A	N/A	0.3	9.0	28.9	0.0	0.0
Vehicle Technologies[11]	156,656	2.9	16.2	55.5	N/A	N/A	150.1	54.0	316.8	1.4	7.6
Weatherization and Intergovernmental	380,067	1.1	0.5	16.8	N/A	N/A	5.4	24.3	12.3	0.1	0.3
Wind and Hydropower	47,600	1.8	4.2	3.9	N/A	N/A	7.6	38.9	87.8	0.0	0.0
National Climate Change Technology Initiative	3,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Facilities and Infrastructure	11,480	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Program Direction	102,375	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sum of programs **	**1,250,745**	**11.7**	**41.4**	**142.9**	**N/A**	**N/A**	**320.2**	**247.9**	**781.2**	**2.2**	**14.8**

** The sum of program benefits differs from the EERE portfolio values in Table ES.2, because interactions among programs are not accounted for in the individual estimates. Sums may not total due to rounding.

[10] Budget request from *FY 2005 Budget-in-Brief*, U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, http://www.eere.energy.gov/office_eere/pdfs/fy05_budget_in_brief.pdf.
[11] The Vehicle Technologies Program is run by the Office of FreedomCAR and Vehicle Technologies.

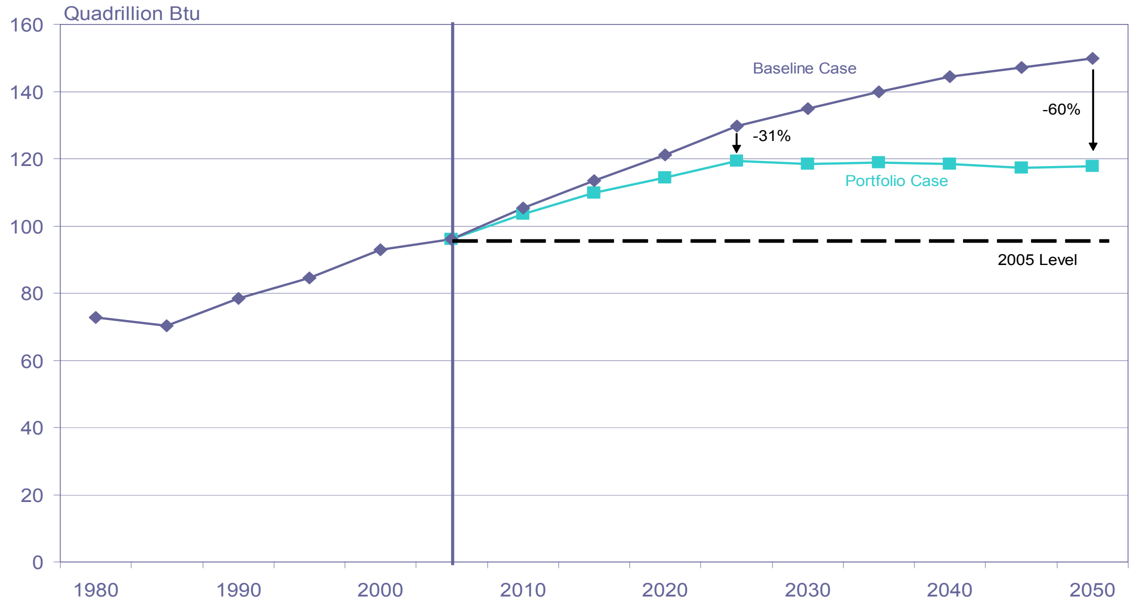

Figure ES.1. U.S. Nonrenewable Energy Consumption, 1980-2000, and Projections to 2050: Baseline and Portfolio Cases

Note: The percentage change in the chart shown for 2025 and 2050 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2025 (or 2050) versus 2005. Data Sources: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025: NEMS-GPRA05; 2030-2050: MARKAL-GPRA05.

Figure ES.2. U.S. Total Energy Expenditures, 1980-2000, and Projections to 2025: Baseline and Portfolio Cases

Note: The percentage change in the chart shown for 2025 and 2050 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2025 (or 2050) versus 2005. Data Sources: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002), Table 3.4 and Table D1, Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025: NEMS-GPRA05; 2030-2050: MARKAL-GPRA05.

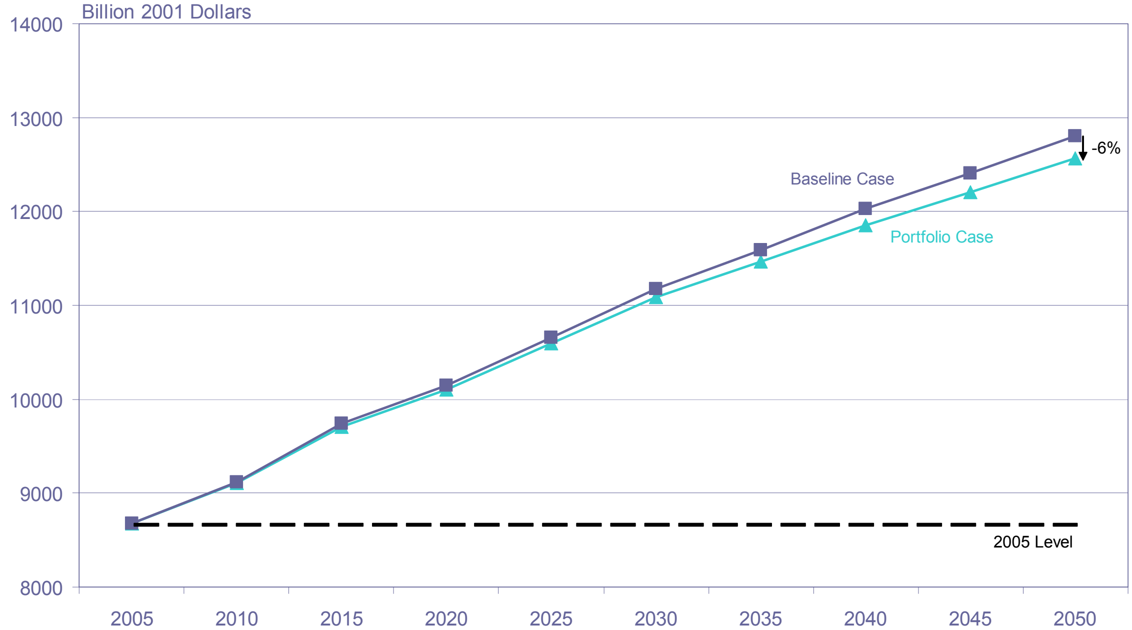

Figure ES.3. U.S. Total Energy-System Cost Projections to 2050: Portfolio Case

Note: The percentage change in the chart shown for 2050 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2050 versus 2005. Data Source: MARKAL-GPRA05.

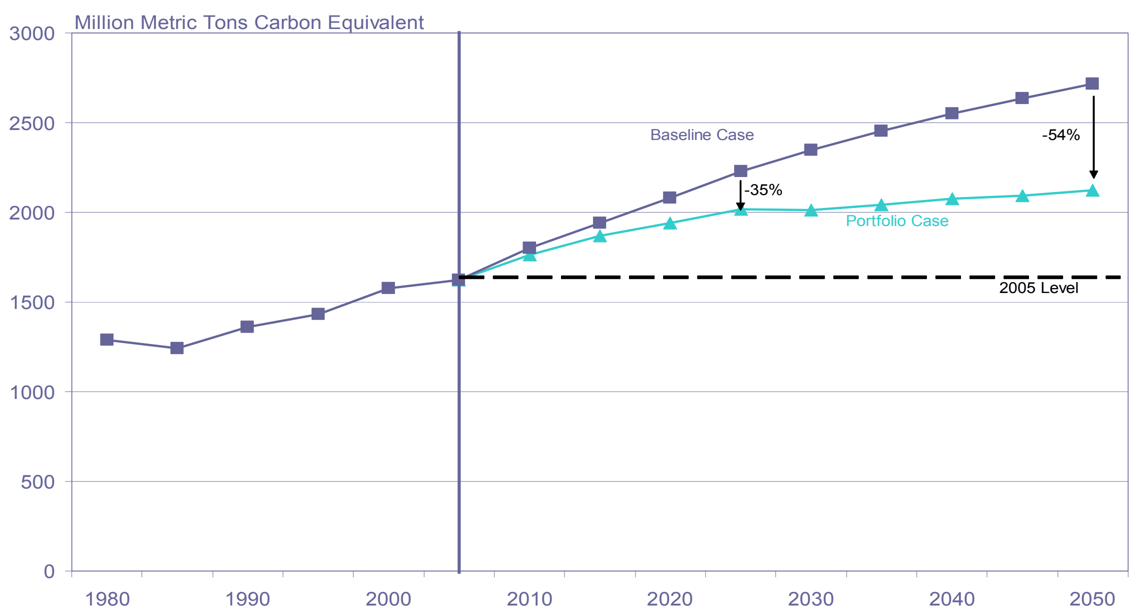

Figure ES.4. U.S. Carbon Dioxide Emissions, 1980-2000, and Projections to 2050: Baseline and Portfolio Cases

Note: The percentage change in the chart shown for 2025 and 2050 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2025 (or 2050) versus 2005. Data Sources: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002), Table 12.2, Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025, NEMS-GPRA05; 2030-2050, MARKAL-GPRA05.

Figure ES.5. U.S. Oil Consumption, 1980-2000, and Projections to 2050: Baseline and Portfolio Cases

Note: The percentage change in the chart shown for 2025 and 2050 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2025 (or 2050) versus 2005. Data Sources: 1980-2000, EIA, *Annual Energy Review 2002*, DOE/EIA-0384 (2002), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025, NEMS-GPRA05; 2030-2050, MARKAL-GPRA05.

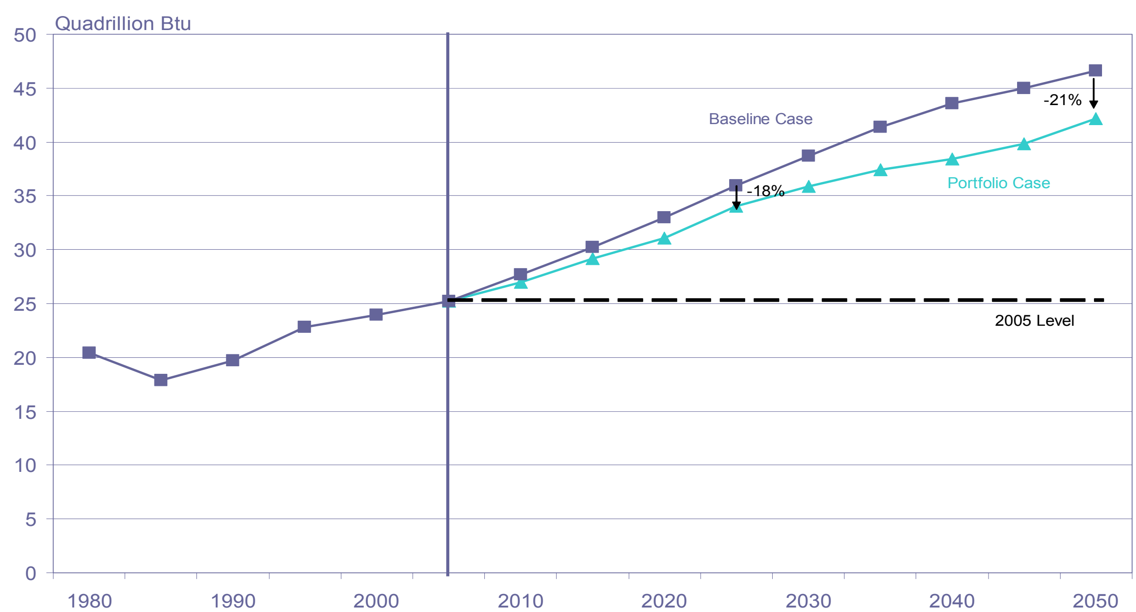

Figure ES.6. U.S. Natural Gas Consumption, 1980-2000, and Projections to 2050: Baseline and Portfolio Cases

Data Sources: 1980-2000, EIA, *Annual Energy Review 2002*, DOE/EIA-0384 (2002), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025, NEMS-GPRA05; 2030-2050, MARKAL-GPRA05.

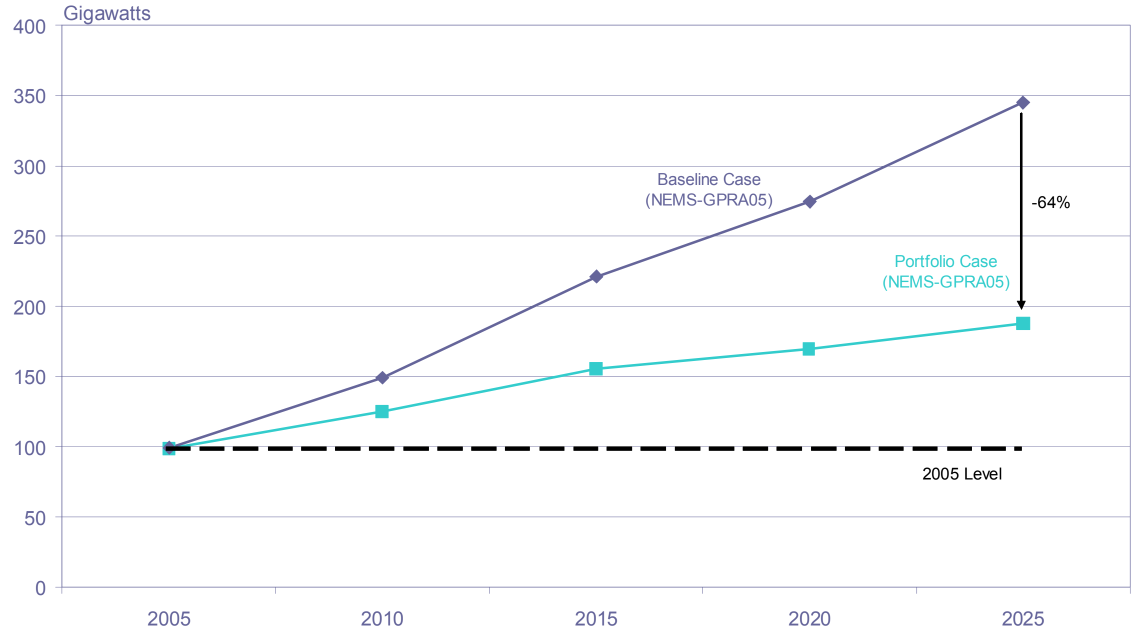

Figure ES.7. U.S. Central Conventional Electricity-Capacity Addition Projections to 2025: Baseline and Portfolio Cases

Note: The percentage change in the chart shown for 2025 is the difference between the Baseline Case and the Portfolio Case, compared to the difference between the values of the Baseline Case in 2025 versus 2005. Data Source, NEMS-GPRA05.

CHAPTER 1

INTRODUCTION

The Office of Energy Efficiency and Renewable Energy (EERE) develops—and encourages consumers and business to adopt—technologies that improve energy efficiency and increase the use of renewable energy. This report describes analysis undertaken by EERE to better understand the extent to which the technologies and market improvements funded by its fiscal year (FY) 2005 Budget Request[1] will make energy more affordable, cleaner, and more reliable.

This benefits analysis helps EERE meet the provisions of the Government Performance and Results Act (GPRA) of 1993 and the President's Management Agenda (PMA). GPRA requires Federal Government agencies to develop and report on output and outcome measures for each program.[2] This EERE benefits analysis supports these GPRA requirements by developing an assessment of the benefits that may accrue to the Nation if the performance goals (outputs) of EERE's programs are realized. The estimates of consumer energy-expenditure savings, energy-system cost savings,[3] carbon emission savings, and reduced reliance on fossil fuels that are reported here result from the increased use of energy-efficient technologies and increased production of renewable energy resources—which are supported by the technology advances and market adoption activities pursued by EERE programs.

Shortly after GPRA was enacted, EERE initiated a corporate approach to benefits analysis that examined the energy, economic, and environmental impacts of program efforts. Through the 1990s, EERE program offices continued to refine their benefits-analysis methodologies and assumptions. An annual external review of the methodologies and assumptions employed was initiated in 1997 and continued through 2001 when EERE was reorganized. Although the benefits analysis has changed since it was initiated 10 years ago, the amount of energy saved or displaced continues to be the key measure of the EERE program impact.

This benefits analysis also supports the President's Management Agenda. The analysis summarized in this report is based on the modeling of program performance goals or outputs. EERE's programs develop these goals based on the following key assumptions:[4]

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[1] See http://www.eere.energy.gov/office_eere/budget.html.

[2] See the Government Performance Results Act (GPRA) of 1993 at http://www.whitehouse.gov/omb/mgmt-gpra/gplaw2m.html and http://www.whitehouse.gov/omb/circulars/a11/02toc.html

[3] NEMS-GPRA05 estimates consumer expenditure savings, which are the gross savings from avoiding purchased energy. They do not include the incremental investment required to achieve these savings. MARKAL-GPRA05 estimates energy-system costs savings, which includes both the savings from avoiding purchased energy and the incremental investment required for the advanced energy technology.

[4] Achieving program goals is generally not dependent on a single technical pathway, but instead encompasses a number of alternative approaches, of which some may fall short without jeopardizing realization of the final goal. The pursuit of multiple pathways can increase the likelihood of achieving program goals, thereby reducing the risk of the program. Risk is being addressed in a separate EERE effort to develop a standard approach to risk assessment.

- Programs will be funded at the levels requested in DOE's FY 2005 Budget Request;
- Funding levels will remain constant in inflation-adjusted dollars or increase to accommodate key initiatives in particular cases, as indicated;

By basing estimated benefits on budget levels, the analysis addresses the performance-budget integration goal of the PMA. This analysis also provides the benefits sought in the R&D Investment Criteria, developed by the Office of Management and Budget (OMB) for the PMA.

Role of Benefits Analysis in Performance Management

EERE employs a widely used logic model[5] as the foundation for managing its portfolio of efficiency and renewable investments, and for ensuring that these investments provide energy benefits to the Nation. In its simplest form, a logic model identifies budget and other *inputs* to a program, *activities* conducted by the program, and the resulting *outputs* and *outcomes* of those activities. The logic model employed by EERE (**Figure 1.1**) provides an integrated approach that explicitly links requested budget levels to performance goals and estimated benefits—and helps ensure that estimated benefits reflect the funding levels requested. The elements of the logic model, which are specified in GPRA, are included in the annual budget request.

Multiyear Program Plans (MYPPs), developed by each of EERE's 11 programs, address the *inputs* required, the *activities* that will be undertaken with their requested budget, the performance *milestones* they expect to achieve as they pursue these activities, and the resulting products or *outputs* of this effort.[6] Inputs may include cost-shared or leveraged funds, as well as EERE program dollars—and may also include advances by others on which the program builds. Performance milestones capture intermediate points of discernable progress toward outputs and are used by program managers, DOE, OMB, and others to track program progress toward their outputs. Outputs, often referred to as "program goals" or "program performance goals,"[7] are the resulting products or achievements of an overall area of activity. EERE's R&D programs typically specify their outputs in terms of technology advances (*e.g.*, reduced costs, improved efficiency), while deployment programs develop outputs related to their immediate market impacts (*e.g.*, number of homes weatherized). Outputs evolve over time as the program pursues increasing levels of technology performance or market penetration.[8]

This benefits analysis links these program outputs to their market impacts or outcomes. EERE's programs have discernable effects on energy markets, both by reducing the level of energy

[5] The logic model is a fundamental program planning and evaluation tool. For more information on logic models, see: Wholey, J. S. (1987). *Evaluability assessment: developing program theory. Using Program Theory in Evaluation*. L. Bickman. San Francisco, Calif., Jossey-Bass. 33. Jordan, G. B. and J. Mortensen (1997). "Measuring the performance of research and technology programs: a balanced scorecard approach." *Journal of Technology Transfer* 22(2). McLaughlin, J. A. and J. B. Jordan (1999). "Logic models: a tool for telling your program's performance story." *Evaluation and Program Planning* 22(1): 65-72.
[6] Appendices B through M provide more information on each program's multiyear program plan and the inputs, activities, milestones, and outputs contained therein.
[7] Some programs derive their outputs through technology-cost simulation models to develop the specific requirements to meet overall program cost and performance goals. Specific details of the representation of the program outputs in NEMS-GPRA05, MARKAL-GPRA-05, and the underlying program analysis and documentation are found in Chapters 4 and 5 of this report and Appendices B through M.
[8] The level of risk for the programs is assessed qualitatively as part of the Office of Management and Budget (OMB) R&D Investment Criteria. EERE is developing a standard approach to assessing technology and program risk.

demand (through efficiency improvements) and by changing the mix of our energy supplies (through increased renewable and distributed energy production). EERE incorporates these two effects in its primary *outcome*—the displacement of conventional energy demand.

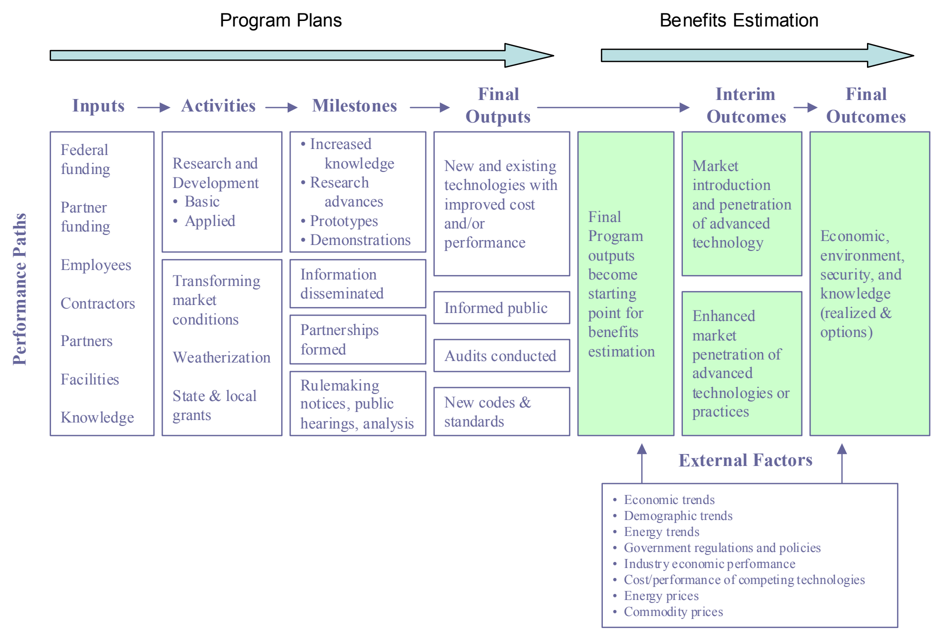

Figure 1.1. Generalized EERE Logic Model

These changes in energy use provide the basis for the economic, environmental, and security benefits estimated here. The extent to which a new technology or a deployment effort changes energy markets will depend on a variety of external factors. The future demand for energy, its price, the development of competing technologies, and other market features (such as consumer preferences) all will contribute to the marketability and total sales of a new technology.

Benefits Framework

The EERE Benefits Framework addresses the last three columns of the logic model: the link between program outputs with resulting outcomes and benefits. The benefits analysis is based on the specific program goals or outputs specified by EERE programs in their program plans and the EERE budget request, as well as estimated future energy market conditions (external factors). EERE estimates its primary outcome—displaced conventional energy consumption—by comparing future energy consumption with and without the contributions of its program outputs. The market impacts of each of the 11 programs are assessed separately and then combined to assess the benefits of EERE's overall portfolio.[9]

[9] EERE's benefits analysis, which measures final outcomes due to EERE programs and a host of other external factors as shown in Figure 1.1., is distinct from impacts analysis, which determines the portion of outcomes having a causal relationship with EERE's actions.

EERE, along with the Office of Fossil Energy (FE), is in the process of adopting a framework initially developed by the National Research Council (NRC) to assess the benefits associated with past EERE research efforts.[10] EERE's annual estimates of prospective benefits have been incorporated into an integrated framework addressing the benefits of both existing and future program activities. The framework is represented in a matrix, in which the rows distinguish among four types of benefits, and the columns represent different elements of time and uncertainty.

This report addresses the three shaded cells of the matrix, reflecting benefits under a business-as-usual energy future (**Figure 1.2**). EERE and FE currently are developing methods for assessing the value to the country of developing technologies that prepare the Nation for unexpected energy needs. These results will be in the "option" column in future reports.[11] Similarly, EERE is in the process of extending the NRC analysis of realized benefits to include its full portfolio.

	Realized Benefits and Costs	Expected Prospective Benefits and Costs	Options Benefits and Costs
Economic Benefits and Costs		✓	
Environmental Benefits and Costs		✓	
Security Benefits and Costs		✓	
Knowledge Benefits and Costs			

Figure 1.2. FY 2005 Benefits Metrics Reported

Completing the cells of this matrix in ways that provide comparable results across programs (and DOE offices) poses a number of analytical challenges, especially in light of the varied portfolio that EERE maintains:

- **Standard baseline(s) and methodological approaches.** EERE uses the Energy Information Administration's (EIA) *Annual Energy Outlook 2003* (*AEO2003*) Reference Case as a consistent starting point for analysis of all of its programs.[12] A standard set of methodological approaches (guidance) is used to assess the incremental improvements to energy efficiency and renewable energy production, resultant from realization of EERE program goals. This guidance is applicable to all of EERE's program activities and markets.

[10] See *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000*, National Research Council (2001) for the original framework. DOE's offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, and Science cosponsored DOE's "Estimating the Benefits of Government-Sponsored Energy R&D" conference in March 2002 to explore ways of extending this framework to include the prospective benefits of program activities. As a result of the conference, the matrix was revised by placing knowledge as a benefit and explicitly showing expected prospective benefits and costs in addition to realized benefits and costs. The conference report is available at www.esd.ornl.gov/benefits_conference.

[11] For its retrospective study, the NRC defined an option as a technology that is fully developed—but for which existing market or policy conditions are not favorable for commercialization. Because current technology choices are known, noncommercial (but developed technologies) are options, by default. A more general definition for prospective analysis—expressed in the Real Options literature—defines a real option as an asset, such as a technological innovation that creates future choices (*i.e.*, options) and establishes an analytic decision-making framework on how to enhance asset value at future points in time. See Dixit, Avinash K., and Robert S. Pindyck, *Investment under Uncertainty*, Princeton University Press, Princeton, New Jersey (1994).

[12] See *The Annual Energy Outlook 2003 with Projections to 2025*, January 2003, DOE/EIA-0383 (2003), available at http://www.eia.doe.gov/oiaf/archive/aeo03/pdf/0383(2003).pdf.

- **Varied markets.** Program activities target all end-use markets (buildings, industry, transportation, and government) and energy-supply markets (use of renewable energy as new sources of liquid and gaseous fuels, and electricity). Because these markets vary enormously in structure, regulation, and consumer preferences, a fairly detailed, market-specific analysis often is needed to gain sufficient understanding of the size and potential receptivity of each market to EERE's activities. EERE strives to incorporate these unique market features that are likely to have a significant impact on the resulting benefits.

- **Varied time frames.** The analytical time frame extends from a few years to the decades that are required for the development of new energy sources, infrastructure, market penetration, and product life cycle. This expansive time frame requires a baseline and analytical tools that can address energy markets in the short, mid-, and long term. This report addresses midterm (5–20 years) and long-term (20–50 years) time frames.

- **Numerous market feedbacks.** EERE technology and deployment efforts can have large enough effects on their respective energy markets that they generate supply or price feedbacks. EERE's products also can interact with each other across their respective energy markets. For example, efficiency improvements in end-use markets can be large enough to forestall the development of new electricity-generating plants, reducing the potential growth of wind and other renewable electricity sources. Past EERE experience indicates that failure to reflect market responses tends to overestimate benefit levels. EERE utilizes integrated energy-economic models to produce final benefit estimates that consider these feedbacks and interactions at the program and portfolio levels.

Benefits Analysis Team

This report summarizes program benefits analysis undertaken by experts in energy technology programs, energy markets, and energy-economic modeling. The primary team members and their areas of responsibility are listed below.

Report Managers

- EERE
  - Integrated: MaryBeth Zimmerman
  - Biomass: Tien Nguyen
  - Buildings: Jerry Dion
  - Distributed Energy Resources (DER): Michael York
  - Federal Energy Management: David Boomsma
  - Geothermal: Cathy Short
  - Hydrogen, Fuel Cells, and Infrastructure Technologies: Jeff Dowd
  - Industry: Peggy Podolak
  - Solar: Tom Kimbis
  - Vehicle Technologies: Phil Patterson
  - Weatherization and Intergovernmental: Michael Gonzalez
  - Wind and Hydropower: Linda Silverman

- Contractors
  - Project Manager: Doug Norland (NREL)
  - Guidance: Patrick Quinlan (NREL), John Mortensen (Independent Consultant)
  - Appendices: Michael Berlinski (NREL)
  - Editorial: Michelle Kubik (NREL)

Analysis Team

- Energy-Economic Integration: Frances Wood, John Holte, Aliza Seelig (OnLocation, Inc.); Chip Friley, John Lee (BNL)
- Biomass: Lynn McLarty (TMS); David Andress, Tracy Carole (Energetics)
- Buildings: Sean McDonald, Dave Anderson, David Belzer, Donna Hostick, (PNNL)
- DER: Chris Marnay (LBNL)
- Federal Energy Management: Daryl Brown, Andrew Nicholls (PNNL)
- Hydrogen and Fuel Cells: Margaret Singh, Matt Kauffman, Phil Patterson (EERE)
- Geothermal: Dan Entingh (PERI)
- Industry: Jim Reed (Independent Consultant)
- Renewables (all): Chris Marnay, Kristina Hamachi LaCommare (LBNL)
- Solar: Robert Margolis (NREL), Jim McVeigh (PERI)
- Vehicle Technologies: Margaret Singh (ANL), Jim Moore (TA Engineering), Elyse Steiner (NREL)
- Weatherization and Intergovernmental Programs (WIP): Sean McDonald, David Anderson, Nancy Moore (PNNL); Elyse Steiner (NREL)
- Wind and Hydropower: Tom Schweizer, Joe Cohen, Jim McVeigh (PERI); Jack Cadogan, James Ahlgrimm (EERE)

In all cases, these lead analysts drew from the studies and expertise of many others. Much of this supporting work can be found in the references provided here and in the appendices.

Report Organization

This report is organized into four additional chapters. **Chapter 2** describes the process and methodology employed by EERE to estimate program and portfolio economic, environmental, and security benefits from its RD&D programs. **Chapter 3** presents the overall results of the savings estimates from the individual programs and from a total EERE portfolio perspective. **Chapter 4** describes, in detail, the estimated midterm benefits of each program area using NEMS-GPRA05. **Chapter 5** describes, in detail, the estimated long-term benefits of each program area using MARKAL-GPRA05.

Thirteen appendices are included. **Appendix A** provides the Baseline and Portfolio Cases. **Appendices B through M** provide program-analysis team inputs for EERE's programs.

CHAPTER 2

EERE BENEFITS-ANALYSIS PROCESS

The Office of Energy Efficiency and Renewable Energy's (EERE) benefits-analysis process involves three major steps (**Figure 2.1**). In **Step 1,** EERE's Office of Planning, Budget, and Analysis (PBA) develops a standard baseline and methodological approach (guidance) to help ensure consistency in estimates across programs. In **Step 2,** EERE's programs develop specific technology and market information, which is necessary to understanding the potential roles of each program in its target markets. In **Step 3**, PBA uses this program and market information to assess the impacts of each EERE program (as well as the overall EERE portfolio) on energy markets in the United States using integrated energy-economic models.

STEP 1 – Baseline Case and Guidance

- Create a Baseline Case without EERE RDD&D.
- Make any necessary updates to EERE's guidelines on estimating benefits.

↓

STEP 2 – Program and Market Inputs

- Review the baseline projections of the timing and rate of adoption of EERE technologies.
- Assess the potential roles of each program's performance goals in these future energy markets.
- Develop inputs to Step 3.

↓

STEP 3 – Program and Portfolio Benefits Estimates

- Develop estimates of individual program benefits (the Program Case).
- Develop estimates of the combined benefits of all programs (the Portfolio Case).

Figure 2.1. EERE Program and Portfolio Benefits-Analysis Process

Step 1: Baseline Case and Guidance

Baseline Case

The EERE Baseline Case is a projection intended to represent a possible future U.S. energy system without the effect of EERE programs. This Baseline Case is intended to serve four purposes: First, it assures that each program's benefits are estimated using the same initial forecasts for economic growth, energy prices, and levels of energy demand. Second, it assures that these initial assumptions are consistent with each other; *e.g.*, that the level of electricity demand expected could be met at the electricity price assumed. Third, it provides a basis for assessing how well renewable and efficiency technologies might be able to compete against future, rather than current, conventional energy technologies (*e.g.*, more efficient central power generation). Fourth, it helps ensure that underlying improvements in efficiency and renewable energy are not counted as part of the benefits of the EERE programs.

EERE used the Energy Information Administration (EIA) *Annual Energy Outlook 2003* (*AEO2003*) Reference Case as the starting point for developing the Baseline Case.[1] The *AEO2003* Reference Case provides an independent representation of the evolution of energy markets. This forecast reflects expected changes in the demand for energy, technology improvements that might improve the efficiency of energy use, and changes in energy-resource production costs, including renewable energy. The *AEO2003* Reference Case also includes current energy policies (*e.g.*, state renewable portfolio standards) that facilitate the development and adoption of these technologies. These policies are kept in the Baseline Case to ensure that EERE's benefits estimates do not include the expected impacts of such policies.

In establishing its Baseline Case, EERE makes a number of modifications to the *AEO2003* Reference Case (**Table 2.1**). The modifications include removing discernable representations of EERE programs, updating policy and market factors where additional information is available, and improving the structural representation of markets important to EERE technologies. While described here for the Baseline Case, some of these changes affect the Program and Portfolio Cases as well.

Modifications are made to the same model—the National Energy Modeling System (NEMS)—used by EIA in developing the *AEO2003*. To distinguish it from EIA's version, the model is referred to as NEMS-GPRA05. The *AEO2003* Reference Case is also the starting point for the long-term (to 2050) benefits modeling using MARKAL-GPRA05. The Baseline Cases for both NEMS-GPRA05 and MARKAL-GPRA05 are aligned as closely as possible, because the two models are different in their internal design.[2]

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[1] *The Annual Energy Outlook 2003 with Projections to 2025*, January 2003, DOE/EIA-0383 (2003). See http://www.eia.doe.gov/oiaf/archive/aeo03/pdf/0383(2003).pdf. EERE is codeveloping, with the Office of Fossil Energy, scenarios to reflect several potential energy futures, pursuant to a recommendation by the National Research Council to reflect market uncertainties (referred to as "option value") and suggestions made in a follow-up conference on ways to represent market uncertainties in benefits analysis. Scenarios will include differences in policy, as well as potential differences in energy markets.

[2] See Box 4.1 in Chapter 4 for an overview of NEMS and Box 5.1 in Chapter 5 for an overview of MARKAL. General information on energy-economy modeling is contained in last year's report, *Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs FY2004 – FY 2020* (April 2004), available at http://www.eere.energy.gov/office_eere/gpra_estimates_fy04.html.

Table 2.1. Summary of Baseline Changes from the AEO2003

	AEO2003	GPRA Baseline Case
Removal of EERE Programs		
Million Solar Roofs	0.4 GW installed 2004 to 2025	Removed
Hydroelectric capacity	Roughly constant hydro capacity and generation	6% reduction by 2025
Cellulosic ethanol production	0.6 billion gallons by 2025	0.15 billion gallons by 2025
DG technology improvement	Significant improvement	Some improvement but less
Distributed peak-load technology	5% fixed capacity factor	2.5% fixed capacity factor, Reciprocating engines added
Energy Market Updates		
PV system size	2 kW residential, 10 kW commercial	4 kW residential, 100 kW commercial
PV maximum market share	30% for both residential and commercial	60% for residential and 55% for commercial
CHP commercial building maximum share	30%	50%
California PV subsidy	Not included	Included for residential systems
Solar water heat	New homes not represented, Maximum 20% of replacement market	New homes represented, Maximum 50% of replacement market
Cellulosic conversion efficiency	90 to 103 gallons of ethanol per dry ton of biomass	82 to 101 gallons of ethanol per dry ton of biomass
Structural Changes		
Wind module	One capital cost and resource multiplier for all wind classes	Capital costs and resource multipliers for each wind class
Commercial shell efficiency	Index	Technology representation
Commercial DG algorithms		Market share and stock accounting modified

Removal of EERE programs. EIA includes some of the impacts of EERE's programs in its Reference Case. In developing the Baseline Case, EERE removes these representations so that they can be analyzed in the Program and Portfolio Cases. For example, EERE removed EIA's estimate of rooftop photovoltaic installations resulting from the Million Solar Roofs Initiative from the EERE Baseline Case. EERE also modified the *AEO2003* assumption of roughly constant hydroelectric capacity over time to reflect the expectation that without more environmentally benign turbine designs, some reduction in hydroelectric capacity would occur as a result of relicensing requirements.[3] The *AEO2003* constrains the maximum growth rate for cellulosic ethanol production. EERE further constrained this growth rate by a factor of 4 in the Baseline Case to reflect the absence of EERE program involvement.

The *AEO2003* forecast includes technology improvements in all areas of energy demand and supply. Identifying what portion of these improvements is due to EERE programs is extremely difficult. For the Baseline Case, EERE modified technology improvements where the *AEO2003* appeared to already incorporate EERE program goals. Technology characteristics that were modified for the Baseline Case include cost and efficiency improvements of distributed combined heat and power (CHP) technologies that were reduced to reflect expected effects without an ongoing Distributed Energy Resources (DER) Program. In addition to CHP in the buildings and industrial sectors, NEMS characterizes two distributed generation (DG)

[3] See the Hydropower Program documentation provided in Appendix L for a description of hydropower capacity expectations.

technologies within the electricity sector that are options to reduce transmission and distribution expenses through strategic location of generators. One of these is defined as a base-load technology and the other as a peaking technology. The analysts modified the latter to represent reciprocating engines (lower capital costs and lower efficiency), and the fixed capacity factor was reduced from 5 percent to 2.5 percent.

Energy Market Updates. The analysts made a few other modifications to reflect updated information about energy markets. The size of typical photovoltaic (PV) systems was increased from 2 kW to 4 kW in residential building and from 10 kW to 100 kW in commercial buildings to reflect recent PV installation experience and trends. The maximum market for PV systems was increased from 30 percent to 55 percent in the commercial sector and to 60 percent for residential PVs. Similarly, analysts increased the maximum market share for gas-fired distributed generation technologies from 30 percent to 50 percent in the commercial sector. California PV credits were incorporated in the Pacific region. Analysts added solar water heat to the slate of technologies for new homes, and increased the share of the replacement market in which it can compete from 20 percent to 50 percent. The conversion efficiency of cellulosic ethanol was updated to reflect technical targets that are more recent than those used by EIA.[4] These changes allow the models to make greater use of these technologies in the future than would be allowed under the *AEO2003* Reference Case, based on observed changes in the energy market.

Structural Changes. In a few cases, analysts made structural changes to improve the model's representation of markets important to EERE technologies. The wind module was modified so that each of the three wind classes is treated more discretely with separate capital costs and resource multipliers. These regional wind-resource cost multipliers increase capital costs as increasing portions of a wind class are developed in a given region to reflect (1) declining natural resource quality, (2) required transmission network upgrades, and (3) competition with other market uses, including aesthetic or environmental concerns.[5] The shell indices in the commercial module were replaced with a technology choice algorithm necessary for representation of EERE shell technologies. In addition, analysts made alterations to the distributed generation algorithm in the building modules to smooth[6] new market shares, to reflect market adoption data gathered by the DER Program[7], to account for the efficiency of using waste heat from combined heat and power systems, and to account for buildings that have already installed a DG technology.

The adjustments to the *AEO2003* Reference Case result in an insignificant difference in energy consumption. For example, nonrenewable energy demand in the *AEO2003* Reference Case is 130.3 quadrillion Btu (quads) in 2025. The EERE Baseline Case value for 2025 is 130.1 quads, a difference of 0.2 quads or 0.15 percent. The closely aligned Reference and Baseline Cases contain considerable technological improvement. The extent of this technological improvement

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[4] The conversion efficiencies in the *AEO2003* are vintage 1998. These were updated based on modeling runs by NREL's biofuels analytic group. See National Renewable Energy Laboratory, Kelly Ibsen memorandum to Tien Nguyen, DOE, on NREL Reported Biomass-to-Ethanol Cases, 1999-2001.

[5] In the *AEO2003* version of NEMS, these multipliers are applied to the entire wind resource in each region; whereas, in NEMS-GPRA05, they are applied separately by wind class. This latter treatment tends to be more restrictive because cost increases due to resource depletion occur more quickly for the best wind class.

[6] An algorithm based on integer values (payback in years) was replaced with a continuous functional form.

[7] *Market Trends in the U.S. ESCO Industry: Results from the NAESCO Database Project*. Goldman, C., J. Osborn and N. Hopper, LBNL, and T. Singer, NAESCO, May 2002, LBNL-49601.

is partly reflected in the declining energy intensity during the forecast period. While nonrenewable energy demand in the Baseline Case increases by 35 percent from 2005 to 2025 (to 130 quads) and by 56 percent from 2005 to 2050 (to 150 quads), underlying energy efficiency and renewable energy improvements contribute toward a 26 percent reduction in nonrenewable energy intensity (nonrenewable energy used per dollar of GDP produced) by 2025 and a 49 percent reduction by 2050 (**Figure 2.2**) .[8] The impact of the improved intensities is substantial. If nonrenewable energy intensity were to remain constant at 2005 levels, then nonrenewable energy demand would be 35 percent higher in 2025 and 97 percent higher in 2050 than it is under the Baseline Case.

Improvements in renewable energy technologies are also contained in the Baseline Case. Between 2005 and 2025, renewable energy technology improvements result in increases in electric generation (in billions of kWh) of 27 for geothermal, 28 for biomass, 7 for wind, 4 for municipal solid waste, 19 for photovoltaics, and 0.3 for solar-thermal.

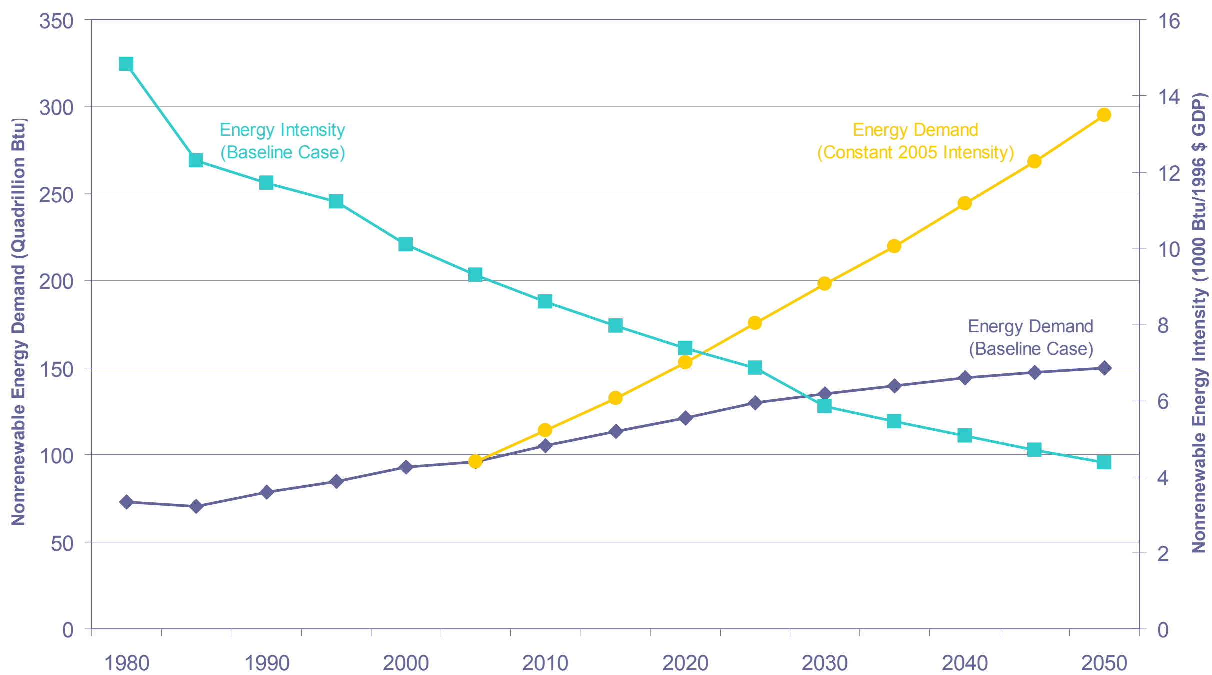

Figure 2.2. U.S. Nonrenewable Energy Demand and Energy Intensity, 1980-2000, and Baseline Projections to 2050

Data Sources: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Tables 1.3, E1 Web site http://www.eia.doe.gov/emeu/aer/contents.html; 2005-2025, NEMS-GPRA05; 2030-2050, MARKAL-GPRA05.

EERE benefits estimates do not include any of these efficiency or renewable Baseline Case improvements. Rather, the R&D improvements represented in the Baseline Case provide the

[8] Energy-intensity changes result from a mix of structural changes in the economy (*e.g.*, growing service sector) and efficiency improvements. Two recent EERE-sponsored studies provide additional background on understanding the sources of changes to our energy intensity: Ortiz and Sollinger, *Shaping Our Future by Reducing Energy Intensity in the U.S. Economy; Volume 1: Proceedings of the Conference* (2003, Rand Corporation); and Bernstein, Fonkych, Loeb, and Loughran, "State-Level Changes in Energy Intensity and their National Implications," (2003, Rand Corporation).

"next best technologies" against which additional EERE improvements are compared. More detail from EERE Baseline Case projections is in **Appendix A**.

Guidance

In order to improve the consistency of estimates across EERE's portfolio, EERE utilizes common methodological approaches, definitions, and conversion factors. Prior to the reorganization, EERE utilized these common elements in the form of an annual "GPRA Data Call"[9] to the five EERE Sectors, which undertook separate analyses based on these common guidelines. With the reorganization, the benefits-analysis team utilizes this methodology directly, including:

Definitions. Common definitions for benefits metrics and related terms are provided.

Converting nominal dollars to real dollars. The results of EERE's benefits analysis are reported in constant ("real") dollars as opposed to current/future year ("nominal") dollars to compensate for the effects of inflation over time. In cases where the program or other sources provide future expenditures or costs in nominal dollars, these are converted to constant dollars based on a forecasted GDP deflator.

Next best technology. The benefits of EERE technologies are assessed compared to the best technologies expected to be available to the market at the time the EERE technologies are developed—not compared to the technologies available or installed today. The Baseline Case provides the future "next best technologies" against which EERE technologies will compete. In markets where the models do not have explicit technology representation, the "next best technology" is reflected in the Baseline Case rates of technology and market improvements. In most cases, EERE R&D efforts accelerate the development and introduction of these technologies, while its deployment efforts principally accelerate the market penetration of technologies once they have reached the market.[10] In specific cases, the RD&D efforts also may be directed toward changing the attributes of technologies in the market (*e.g.*, less polluting) or of developing technologies that are not reflected in the Baseline Case within the timeline of analysis. (See **Box 2.1—Impact of EERE Programs**).

Market characteristics and penetration rates. It takes time for new products to reach their full market potential, and these market-penetration rates vary considerably by technology and market. The Baseline Case includes assumptions about technology-adoption rates for many markets, primarily through the use of consumer "hurdle rates" or other representations of the

[9] The guidance used for FY 2005 benefits estimates followed the guidance for FY 2003 (see http://www.eere.energy.gov/office_eere/ba/gpra_estimates_fy03.html). EERE will continue to maintain standard assumptions and methodologies for estimating program benefits.

[10] This is a starting assumption. There may be cases in which EERE's efforts principally change the characteristics of the technologies being marketed (*e.g.*, less polluting) rather than, or in addition to, accelerating market introduction and penetration. At times, EERE may be developing technologies that are not expected to be developed by the private sector (*i.e.*, they do not show up in the Baseline Case at all). Finally, some research efforts include built-in deployment components that may result in a combined accelerated introduction and accelerated penetration effect. These variations on the basic approach described above are addressed in the program-level appendices to this report.

trade-off between upfront investment costs and annual operating costs (including energy expenses) over time, as well as other attributes in selected cases. Where technologies are not explicitly represented, adoption rates are embedded in efficiency trends. Efficiency trends may implicitly include capital stock turnover, as well as technology efficiencies and rate of uptake of different technologies. Other market characteristics (such as regional markets, regulatory constraints, or typical start-up time for new product lines) can influence adoption rates and also may be specifically represented in the Baseline Case. For R&D activities, the market characteristics and factors affecting adoption rates remain the same for the Program Case and the Baseline Case, unless the new technology would fundamentally change the way the target markets operate (*e.g.*, accelerate stock turnover or increase consumer acceptance of new technologies). For deployment activities, the program output goals provide a basis for assessing the expected acceleration of market-penetration rates (or other changes in market characteristics), due to the program activities in the Program Case.

Technology performance and cost. For R&D programs, the benefits analysis is based on the performance and cost of the technologies being developed or deployed. For each technology (or class of technologies), key technology characteristics include:

- Expected year of technology availability
- Capital costs
- Operations and maintenance (O&M) costs
- Technology product lifetime
- Technology performance and/or energy displaced/unit by fuel type
- Other technology features that might affect market acceptance

Two sets of technology characteristics are of interest: Baseline Case and Program Case. The EERE Baseline Case already includes expected private-sector advances in efficiency and renewable technologies. In many cases, the specific technology characteristics are included directly in the NEMS-GPRA05 and MARKAL-GPRA05; while, in other cases, they are represented through overall rates of technology improvement—and the characteristics for specific technologies must be inferred from these rates. For R&D efforts, the Program Case technology characteristics and costs generally reflect the program output goals. For deployment efforts, the technology characteristics remain the same in the Baseline and Program Cases.

Calculating direct energy and primary energy displaced. NEMS-GPRA05 and MARKAL-GPRA05 provide projections of direct (site) energy savings from end-use programs and the corresponding primary energy reductions. Reduced electricity demand leads to reduced generation and fuel consumption by electric power producers. The amount of fuel consumed (and saved) changes as the marginal efficiency of power production increases with the increased efficiency of conventional, central power production. When the principal market analysis is performed off-line, the resultant energy savings (expressed in direct energy terms) are used as an input to the NEMS-GPRA05 and MARKAL-GPRA05 models. The two models then compute primary energy savings based on the direct energy savings.

Box 2.1—Impact of EERE Programs

For EERE R&D efforts, the initial assumption is that the impact of the program is to accelerate the commercial introduction of a technology (see **Figure 2.3a**). In some cases, that may be the only effect. In other cases, the EERE R&D effort may develop a technology with features that can affect the ultimate size of the market, or that otherwise would not have been developed by the private sector.* For EERE deployment efforts, the initial assumption is that the impact of the program is to accelerate the rate of adoption of a technology already developed and introduced to the market (see **Figure 2.3b**). In some cases, the EERE deployment effort also may impact the total size of the market, in addition to the rate of adoption. In such cases, the program affects the maximum market share the technology achieves.

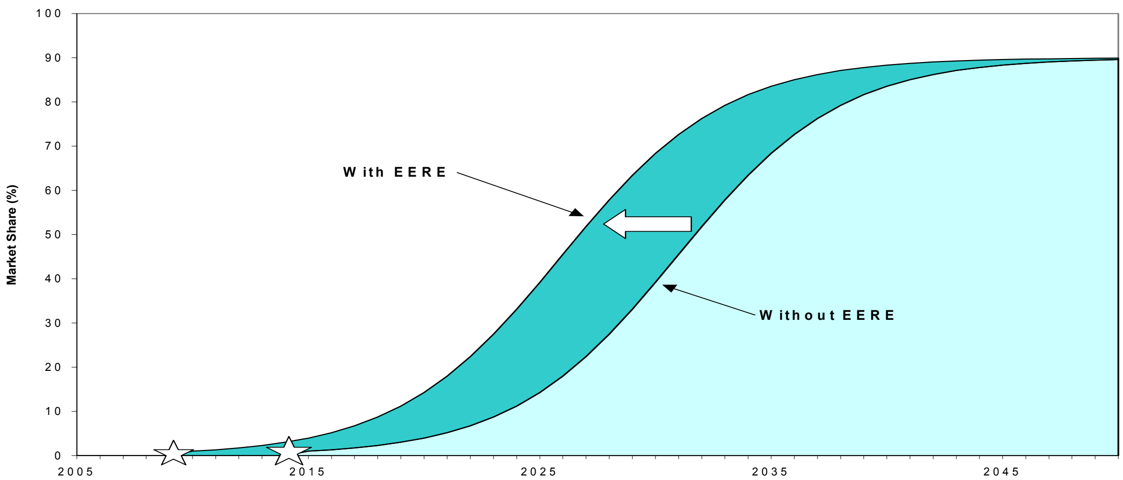

Figure 2.3a. Potential Impacts of EERE R&D Programs on Technology Introduction

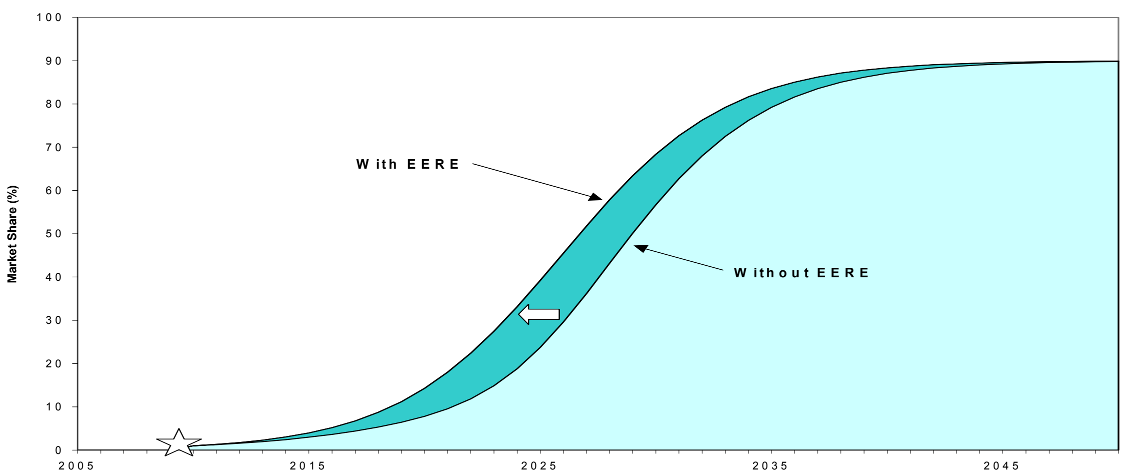

Figure 2.3b. Potential Impacts of EERE Deployment Programs on Market Penetration

*Assuming the technology, or technological characteristic, would have been developed by the private sector anyway. In some cases, technologies are so far from potential commercialization—or so risky—that private-sector firms do not invest in them. In others, the private sector lacks the market incentive to develop technology features, such as improved load-balancing for home appliances (which could improve the reliability of the electricity grid), because the markets do not provide the price signals that would generate profits from these public benefits.

Calculating carbon equivalent emissions reductions. NEMS-GPRA05 and MARKAL-GPRA05 compute carbon emission reductions based on the amount of coal, oil, and natural gas consumed in the Baseline, Program, and Portfolio Cases, as well as the carbon coefficients of each energy source. Carbon emissions are computed using NEMS-GPRA05 and MARKAL-GPRA05. The carbon emissions associated with the displacement of fossil-generated electricity by efficiency or renewable technologies will vary over time and reflect the increasing efficiency of new fossil generators and the dynamic shift in fuel sources.

EERE's ability to apply these methodological approaches varies considerably by program, depending on the availability and cost of market data, the ability to assess public and private-sector technology contributions, and the capability to reflect specific market conditions in energy models available to EERE.

Step 2: Program and Market Inputs

In **Step 2**, program goals and salient target market characteristics are developed as inputs to modeling the benefits estimation in **Step 3**. The effort required under **Step 2** varies considerably, depending on the form in which programs specify their output or performance goals and how NEMS-GPRA05 and MARKAL-GPRA05 utilize this information. It ranges from the compilation of technology goals to detailed market analyses that produce technology penetration rates—and, in some cases, delivered energy savings.

NEMS-GPRA05 and MARKAL-GPRA05 contain detailed technology representations of electricity markets, most residential and commercial end uses, and vehicle choice—but use trends for the representation of industrial efficiency improvements and existing residential shell retrofits. For programs that address these markets, this step simply requires (1) confirming the adequacy of the target market representation in the Baseline Case and (2) providing the program goals in a format consistent with the model. Any updated market characteristic information is used to adjust NEMS-GPRA05 and MARKAL-GPRA05 for both the Baseline Case and the Program Case to avoid ascribing external factors as benefits. Analysts use the program goal information to adjust the commercialization date, technology characteristics, or market penetration rate for the Program Case. The comparison of market technology introduction and market penetration rates, with and without the program goal—and the calculation of the energy displaced—occur within NEMS-GPRA05 and MARKAL-GPRA05.

For much of EERE's portfolio, additional "off-line" analyses are needed to translate information about program technology and market characteristics into usable modeling inputs. This off-line **Step 2** analysis can range from spreadsheet calculations to the use of market-specific models to assess technology or market features that cannot be adequately represented in a broad energy-economic model, or to translate program goals into the variables used in the modeling. In general, analysts perform the most detailed off-line analyses for the Industrial Technologies Program, Weatherization and Intergovernmental Program (WIP), Federal Energy Management Program (FEMP), and portions of the Building Technologies Program. Analysts tailor these off-line analytical approaches to the characteristics of the program and target market being analyzed; but, in any case, they are conducted within the overall guidance provided through the GPRA benefits estimation process.

The market applications for EERE technologies are often very specific, and resulting energy savings for a given technology can vary significantly from one application to another. For example, the impact of upgrading building codes can vary significantly (due to differences in climate and in existing building-code standards) and therefore require analysis at the State level. The Building, Industrial, and WIP programs are most likely to require tailored analytical approaches that address these submarkets.

Where NEMS-GPRA05 and MARKAL-GPRA05 do not include technology-by-technology information (*e.g.*, cost, date of availability), or specific market-penetration rates, it is often necessary to translate program goals into the more general rates of technology improvement used by the models. This is true for the Industrial Technologies Program and some elements of the Building Technologies Program, where numerous specific technology advances or market deployment efforts will accelerate overall efficiency improvements in buildings or factories specified in the Baseline Case.

Off-line analysis also can be required for targeted submarkets that are simply not included in NEMS-GPRA05 or MARKAL-GPRA05—or for which the resulting technology use is not fully market-driven. Examples include the Federal sector (addressed by FEMP) and the Low-Income Weatherization Assistance Program, in which the Federal Government directly purchases home efficiency improvements.

Finally, supporting "off-line" analysis can be required where market functions are not well represented in a full energy-economic model. For example, consumer willingness to pay a premium for electricity produced by environmentally friendly technologies is not represented within the electricity market in NEMS-GPRA05 and MARKAL-GPRA05; and, therefore, another model specifically designed to analyze this market provides the input assumptions on this market segment. Also, programs designed to help overcome institutional barriers to efficiency adoption are often difficult to represent in market-based models.

Because estimating the benefits of achieving program performance goals requires the ability to realistically assess the extent to which future energy markets might adopt the technology and market improvements developed by EERE programs, analysts explore the following features in these off-line analyses:

Target Markets. New technologies will not necessarily be well suited to all applications served by existing markets. Technologies may occupy niche markets, especially in early years. In some cases, initial markets are geographically limited as well. Where integrated models do not represent these submarkets explicitly, it may be necessary to develop off-line estimates of the applicable market share for the technology being developed, at least in the early years.

Stock Turnover. Modeling stock turnover is crucial to estimating benefits for both new technologies and deployment programs. Analyses of the market adoption of new technologies must consider the rate at which the specific type of energy-using or -producing capital equipment is replaced, in addition to the growth rate of the overall market. Even when a technology is suitable and cost-effective for a percentage of a market, it may take a decade or more for the capital stock in that portion of the market to retire and be replaced. Particularly attractive new technologies might accelerate that turnover. EERE includes this potential for early retirement only when market evidence suggests that the technology improvement is significant enough to overcome typical hurdle rates to new investment. Although stock turnover fluctuates with business cycles, EERE does not incorporate business cycles into its Baseline or Program cases. As a result, nearer-term estimates of benefits, in particular, do not take into account year-to-year fluctuations in energy use attributable to business cycles.

Next Best Technology. Where technology representation is implicit (in a technology improvement index, for instance), the Baseline Case improvement must be translated into improvement rates for a specific set of technologies. Analysts use this set of baseline technologies to assess the specific markets in which the EERE technology might be competitive in different time frames.

Market Penetration. Over time, new technologies typically make their way into markets—and, therefore, affect energy use—gaining their share of new sales as consumers learn about the availability of the product. Manufacturing capacity then grows, and product prices fall with economies of scale and learning.[11] While price helps determine whether a product is cost-effective, on average, energy prices vary by type of customer and region, so that new products may be cost-effective for some customers (a niche market) before they are generally cost-effective. Price, or cost-effectiveness, is often not the only aspect of the new technology or deployment program that shapes its rate of market uptake. Many non-price or cost factors affect consumer behavior.

As an example, the off-line analysis for the Industrial Technologies Program uses a spreadsheet model that provides several possible market penetration curves. The analyst chooses a curve, based on specific information from possible R&D partners, comparison of the new technology to similar technologies, or his or her expert judgment. The benefits guidance for industrial benefits estimation includes historic penetration curves for 11 technologies and offers the analyst five choices of penetration curve shapes. The five choices are accompanied by detailed data on technology equipment, financial, industry, regulatory, and impact characteristics to aid in making the choice. In addition to choosing the shape or the penetration curve, the analyst chooses the year—after all pilot testing and demonstration phases—the new technology is expected to enter the market.

Through the use of specialized spreadsheets or other models,[12] program analysts produce estimates of market penetration and direct energy savings associated with these market sales. However, these "off-line" estimates of direct energy savings are not benefits estimates because they do not account for market interactions. Analysts integrate these off-line estimates within the NEMS-GPRA05 and MARKAL-GPRA05 models as the final part (**Step 3**) of the process.

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[11] See Adam B. Jaffe, Richard G. Newell, and Robert N. Stavins, "Energy-Efficient Technologies and Climate Change Policies: Issues and Evidence," Climate Issue Brief No. 19, *Resources for the Future*, Washington, D.C. (December 1999).
[12] In one case (the Building Technologies Program), a portion of NEMS (the buildings module) was used for off-line analysis.

Step 3: Program and Portfolio Benefits Estimates

The final step for estimating the impacts of EERE's FY 2005 Budget Request is to analyze all EERE's programs in a consistent economic framework and to account for the interactive effects among the various programs. Estimates of individual EERE program energy savings cannot be simply summed to create a value for all of EERE, because there are feedback and interactive effects resulting from (1) changes in energy prices resulting from lower energy consumption and (2) the interaction among programs affecting the mix of generation sources and those affecting the demand for electricity.

The process begins by analysts modeling each EERE program individually within NEMS-GPRA05 and MARKAL-GPRA05 to the extent possible. In each NEMS-GPRA05 and MARKAL-GPRA05 Program Case, only the modeling assumptions related to the outputs of the program being analyzed are changed. The modeling assumptions related to the other EERE programs remain as they were in the EERE Baseline Case. Analysts model each program separately to derive estimated energy savings without the interaction of the other programs. They then compare the results from the NEMS-GPRA05 and MARKAL-GPRA05 Program Cases to the Baseline Case to measure the individual benefits of the EERE program being analyzed.

For programs modeled using NEMS-GPRA05 and MARKAL-GPRA05 directly, analysts compute the Program Case by changing the assumptions representing the program outputs; *i.e.*, the goals or performance targets of the program, such as reducing low wind-speed turbine costs and improving their performance. The R&D programs are represented in NEMS-GPRA05 and MARKAL-GPRA05 through changes in technology characteristics that represent the program goals, to the extent possible. Activities designed to stimulate additional market penetration of existing technologies generally were modeled through changes in consumer hurdle rates or other appropriate market-penetration parameters, with the goal of representing the market share targeted by the program.

In cases where program goals cannot be easily modeled using NEMS-GPRA05 and MARKAL-GPRA05, analysts estimate benefits using a variety of off-line tools, as described in **Step 2**. These supporting analyses typically provide either estimates of market penetration and per-unit energy savings, or total site energy savings that are then used as inputs to NEMS-GPRA05 and MARKAL-GPRA05. In cases where the off-line analyses produce a direct estimate of site energy savings, analysts adjust this information by an "integration factor" and incorporate it in NEMS-GPRA05 and MARKAL-GPRA05 in order to calculate primary energy savings. The amount of the integration factor is based on how much program overlap or "integration" was captured by the off-line tools. The revision is based on the expert judgment of the benefits analysis team. See **Chapters 4 and 5** for discussion of program-by-program benefit estimates, including such reductions.

Once each of the programs (or group of programs) is represented individually within NEMS-GPRA05 and MARKAL-GPRA05, the benefits of EERE's portfolio are estimated by combining all of the program goals into one EERE Portfolio Case.

Detailed projections from the EERE Baseline and Portfolio Benefits Case are in **Appendix A**.

CHAPTER 3

FY 2005 BENEFITS ESTIMATES

The Office of Energy Efficiency and Renewable Energy (EERE) estimates expected benefits for its overall portfolio and for each of its 11 programs. Benefits for the FY 2005 budget request are estimated for the midterm (2010-2025) and long term (2030-2050). Two separate models suited to these periods are employed—NEMS-GPRA05 for the midterm and MARKAL-GPRA05 for the long term.

Benefits estimates are intended to reflect the value of program activities from 2005 forward. They do not include the impacts of past program success, nor technology development or deployment efforts outside EERE's programs. This distinction is difficult to implement in practice, because many research and deployment activities provide continuous improvements that build on past success; and because EERE programs are leveraged with private-sector and other government efforts (*e.g.*, in addition to the Baseline Case, private-sector improvements).

Outcomes and Benefits Metrics

The energy efficiency improvements and additional renewable energy production facilitated by EERE's programs reduce the consumption of traditional energy resources. Reducing energy consumption affords the Nation a number of economic, environmental, and energy security benefits.[1] The extent of these benefits depends on numerous factors including which energy sources are reduced, the costs of the new technologies, and the emissions performance of the energy technologies used. Different EERE portfolios would produce a different mix of benefits, even if the overall level of primary energy savings were the same.

The public benefits resulting from these reductions in the use of traditional energy resources take many forms. Environmental improvements, for instance, can include reductions in local, regional, or global air emissions; reduced water pollution; noise abatement, etc. These public benefits are typically difficult to measure directly, and some aspects are not quantifiable. EERE has developed a set of *indicators* intended to provide a sense of the magnitude and range of the benefits its programs provide the Nation. EERE estimates benefits for the following defined metrics:

Primary Outcome:

> **Energy Displaced - the difference in nonrenewable energy consumption with and without the technologies and market improvements developed by EERE programs.**

[1] This is a categorization of EERE's benefits estimates, based on the framework developed by a National Research Council (NRC) committee. The framework is described in more detail in the Introduction.

Analysts measure energy savings on a primary basis, accounting for the energy consumed in producing, transforming, and transporting energy to the final consumer. Energy savings from underlying private-sector improvements in technologies are not counted. Energy displaced is reported in quadrillion Btus per year (quads/yr).

Primary Benefits:

Economic Benefits: Economic benefits are the potential for EERE technologies to: make energy more affordable by reducing expenditures on energy and energy services, increase economic productivity and GDP through more efficient production processes, reduce the impact of energy price volatility on the U.S. economy by providing more efficient technologies and providing alternative energy sources, and improve the balance of trade by exporting energy technologies. Of these, EERE currently estimates two aspects of affordability—energy-expenditure savings and total system cost savings:[2]

Energy-expenditure savings – The difference in total consumer energy bills with and without the availability of technologies and market improvements developed by EERE technologies. This is an estimate of energy bill savings[3] and does not include the incremental cost to end users of acquiring the new technology. The EIA NEMS model does not currently have the capability to provide net costs in all sectors of the economy. Energy-expenditure savings are reported in billions of 2001 dollars per year.

Total system cost savings – The difference in total systems costs with and without the availability of technologies and market improvements developed by EERE technologies. Total system cost represents the economic cost to society to produce, import, convert and consume energy. It is calculated as the sum of domestic resource-extraction costs, imported fuel costs, and the annualized capital and operating and maintenance costs of energy technologies (including end-use demand devices). Total system cost savings is a net estimate of system costs generated by MARKAL-GPRA05, which unlike the energy expenditure savings estimates generated by NEMS-GPRA05, includes the incremental costs of end-use technologies. Total system cost savings are reported in billions of 2001 dollars per year.

Environmental Benefits: Environmental benefits that can result from use of EERE technologies include, among many others, lower carbon, SOx, NOx, and other air emissions. Of these, EERE currently estimates only the impacts of its programs on carbon emissions:

Carbon savings (*i.e.*, emission reductions) – The difference in the level of U.S. energy-related carbon emissions with and without the availability of EERE technologies and associated market improvements. Carbon emission reductions result from the reductions in fossil fuel consumption when these new supply (renewables) and

[2] Energy-expenditure savings are calculated through 2025 using the NEMS-GPRA05. Total system cost savings are calculated through 2050 using MARKAL-GPRA05.
[3] Energy efficiency improvements and increased use of nonfuel renewable energy (*e.g.*, renewable-generated electricity) reduce energy bills in two ways. Consumers who make energy efficiency or renewable energy investments benefit directly through reduced purchases of energy (quantity component). In addition, the lower demand for energy reduces the price of energy for all consumers (price component).

demand (energy-efficient) technologies are used in the market. As with the energy-savings metric, emission reductions count the effect of upstream energy savings in producing, transforming, and transporting energy to the end user. Carbon savings are reported in million metric tons of carbon (mmtc) equivalent per year.

Security Benefits: Security benefits include improvements in the reliability of fuel and electricity deliveries, reduced likelihood of supply disruptions, and reduced impacts from potential energy disruptions. EERE contributes to these security gains by reducing U.S. reliance on imported fuels, increasing the diversity of domestic energy supplies, increasing the flexibility and diversity of the Nation's energy infrastructure, reducing peak demand pressure on that infrastructure, and providing backup energy sources in the event of outages. Of these aspects of energy security, EERE has developed indicators related to concerns about fuel supplies and the reliability and diversity of electricity supplies:[4]

Oil savings – The difference in total U.S. oil consumption with and without EERE technologies and market improvements. Oil savings are reported in million barrels per day (mbpd).

Natural gas savings – The difference in total U.S. natural gas consumption with and without EERE technologies and market improvements. Natural gas savings are reported in quadrillion Btu per year (quads/yr).

Avoided additions to central conventional power – The difference in central conventional power additions with and without EERE technologies and market improvements. Avoided central conventional power additions result from electricity capacity displaced by efficiency improvements; additional distributed generation capacity (fossil or renewable); and central renewable power-generating capacity.[5] Avoided capacity additions are reported in gigawatts (GW).

In interpreting these metrics, it is important to remember that while the benefits of efficiency and renewable technologies are multifaceted, they are not always distinct or additive. Improvements in balance-of-trade or economic productivity, for instance, are contributory to improved GDP and not additional to improved GDP. Nonetheless, identifying the various types of economic or other contributions can help relate EERE's portfolio to various economic or other policy concerns.

Each of these metrics is ideally measured as a net benefit (*e.g.*, energy bill savings minus the cost to the consumer of investing in the efficient or renewable technology, or including positive and negative environmental impacts). Analysts calculate carbon emission reductions, as well as oil and natural gas savings, on a net basis, including cases in which EERE programs tend to increase

[4] The inclusion of reliability improvements within the security category was part of the NRC suggestions on how to structure the types of EERE benefits. The 2003 blackout in the Midwest and New England indicates the extent to which security and reliability are intertwined.
[5] These measures are not additive and are not the same as a measure of peak-load reduction for conventional electricity or of improved reliability. Renewable capacity additions are not equivalent to capacity additions avoided because of differences in capacity factors and coincidence of renewable generation at system peak (*i.e.*, peak electricity-generation output of wind, for example, may not coincide with the peak demand of the utility system to which it supplies power).

rather than decrease use or emissions. While consumer-expenditure estimates calculated by NEMS-GPRA05 do not reflect the costs to consumers of purchasing more efficient or cleaner technologies, MARKAL-GPRA05 is able to provide estimates of net economic costs.

Portfolio Benefits

Table 3.1 shows the estimated economic, environmental, and security benefits of EERE's overall portfolio of investments in improved energy-efficient technologies, renewable energy technologies, and assistance to consumers in adopting these technologies. Data by five-year increments (2010 to 2025) are shown for NEMS-GPRA05 and by 10-year intervals (2030 to 2050) for MARKAL-GPRA05.[6]

Table 3.1. Annual EERE Portfolio Benefits for FY 2005 Budget Request for Selected Years[7][8]

EERE Midterm Benefits	2010	2015	2020	2025
Energy Displaced				
• Nonrenewable energy savings (quadrillion Btu/yr)	1.8	3.6	6.9	10.4
Economic				
• Energy-expenditure savings (billion 2001 dollars/yr)*	27	51	90	134
Environment				
• Carbon dioxide emission reductions (mmtc equivalent/yr)	35	74	139	213
Security				
• Oil savings (mbpd)	0.2	0.5	1.1	2.1
• Natural gas savings (quadrillion Btu/yr)	0.7	1.0	1.9	1.9
• Avoided additions to central conventional power (gigawatts)[9]	24	66	105	157

EERE Long-Term Benefits	2020	2030	2040	2050
Energy Displaced				
• Nonrenewable energy savings (quadrillion Btu/yr)	7.4	16.5	25.8	32.3
Economic				
• Energy-system cost savings (billion 2001 dollars/yr)*	42	88	171	236
Environment				
• Carbon dioxide emission reductions (mmtc equivalent/yr)	145	334	471	593
Security				
• Oil savings (mbpd)	1.0	4.7	9.0	11.6
• Natural gas savings (quadrillion Btu/yr)	2.6	2.8	5.2	4.5

* Midterm energy-expenditure savings only include reductions in consumer energy bills, while long-term energy-system cost savings also include the incremental cost of the advanced energy technology purchased by the consumer.

[6] NEMS-GPRA05 runs using one-year intervals, while Markal-GPRA05 runs using five-year intervals.

[7] Estimates reflect the benefits associated with program activities from FY 2005 to the benefit year, or to program completion (whichever is nearer), and are based on program goals developed in alignment with assumptions in the President's Budget. Midterm program benefits were estimated using the GPRA05-NEMS model, based on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and using the EIA's *Annual Energy Outlook 2003* (*AEO2003*) reference case. Long-term benefits were estimated using the GPRA05-MARKAL model developed by Brookhaven National Laboratory. Results can differ among models due to structural differences. The models used in this analysis estimate economic benefits in different ways, with MARKAL reflecting the cost of additional investments required to achieve reductions in energy bills.

[8] For some metrics, the benefits estimated by MARKAL-GPRA05 do not align well with those reported by NEMS-GPRA05. Every attempt is made in the integrated modeling to use consistent baselines, input data and assumptions in both models to produce consistent results. However, NEMS and MARKAL are in some respects fundamentally different models (see Boxes 4.1 and 5.1). Discrepancies in the estimated benefits often differ simply because of these model differences.

[9] Small final changes in these estimates were not reflected in the FY 2005 Budget Request.

Energy Displaced: EERE's portfolio significantly dampens the expected growth in nonrenewable energy consumption. Absent the results of EERE's programs,[10] energy use is expected to grow by nearly 34 quads from 2005 to 2025, to about 130 quadrillion Btus of energy and by 54 quads from 2005 to 2050. If the goals of EERE's investment portfolio are achieved and the corresponding market outcomes realized, it will reduce nonrenewable energy consumption by more than 10 quadrillion Btu by 2025, or about 31 percent of the expected incremental growth in energy demand over this time period; and by 32 quadrillion Btus by 2050, or about 60 percent of the expected incremental growth in energy demand over this time period (see **Figure 3.1**). This results in a leveling of nonrenewable energy consumption starting in 2025 despite a growing economy.

Figure 3.1. U.S. Nonrenewable Energy Consumption, 1980-2000, and Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html.

These estimates account for interactions among program results. While some program activities reinforce each other to produce larger benefits than would be evident from each program's individual efforts, in other cases programs compete for the same markets. For example, the various renewable technology programs compete in the electricity-generation market. In addition, activities being funded by some programs reduce the potential market for technologies being developed in other programs. As an example, reductions in electricity demand due to efficiency improvements reduce the size of the generation market and, therefore, the market opportunity for renewable-generation technologies. The overall effect of these interactions is to reduce estimated benefits by about 1.3 quads in 2025 compared to

[10] See Chapter 1 for information on how EERE's "no-program" Baseline Case is developed.

the sum of the individual program benefits; and to reduce estimated benefits by about 7.1 quads in 2050 compared to the sum of the individual program benefits (*i.e.*, Program Case, see **Figure 3.1**).

Economic Benefits: The energy savings resulting from these efficiency and renewable energy contributions are estimated to reduce annual consumer energy expenditures in 2025 by $134 billion (expressed in real 2001 dollars) relative to the baseline projection of $1,030 billion (**Figure 3.2**), or about 13 percent of the nation's expected energy bill.
While these energy bill savings appear to be large, they represent both reduced energy purchases and lower energy prices resulting from reductions in demand. They also exclude incremental costs to end users of acquiring the new technology, because the EIA NEMS model does not currently have the capability to determine this in all sectors of the economy. Lower energy demand dampens fuel costs and reduces the need for expensive new energy infrastructure expenditures. Lower energy prices improve affordability for all consumers, including those who make no additional efficiency or renewable investments as a result of EERE's activities.

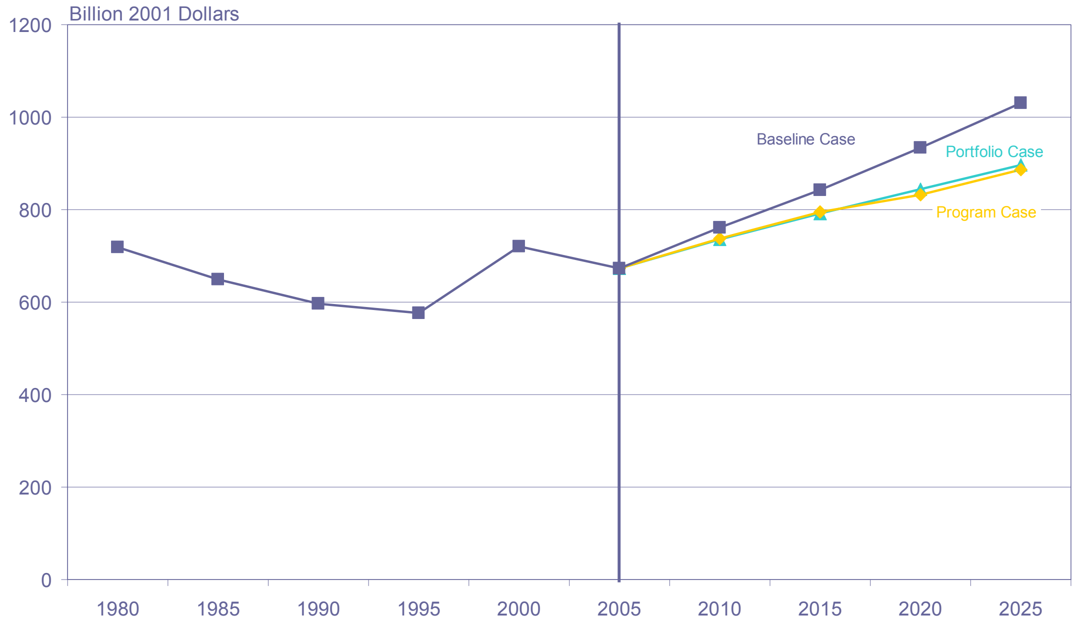

Figure 3.2. U.S. Total Energy Expenditure, 1980-2000, and Projections to 2025: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 3.4 and Table E1, Web site http://www.eia.doe.gov/emeu/aer/contents.html.

The EERE portfolio also will reduce annual total system energy costs by $236 billion (in real 2001 dollars) in 2050 (**Figure 3.3**). This longer-term analysis is done using MARKAL-GPRA05, which includes the incremental costs to end users of acquiring the new technology.

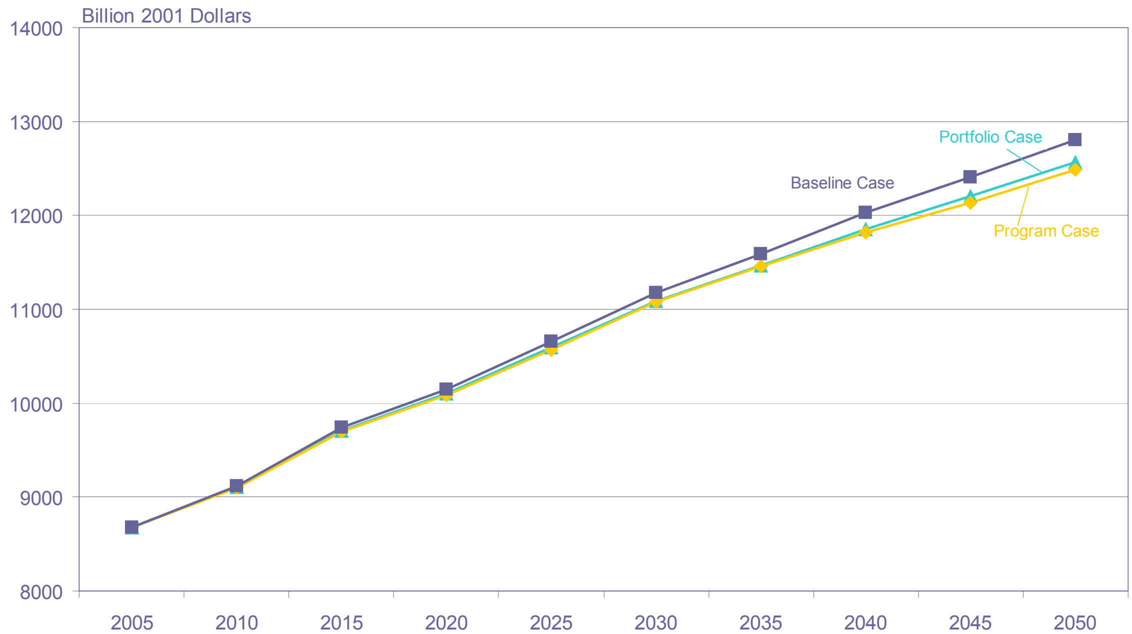

Figure 3.3. U.S. Total Energy-System Cost Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: MARKAL-GPRA05

Environmental Benefits: Annual carbon dioxide emissions are projected to be 213 million metric tons (carbon equivalent) less than the 2025 baseline projection of 2,230 million metric tons—a reduction of about 9.5 percent (**Figure 3.4**) or 35 percent of the expected increase from 2005 to 2025. Annual carbon dioxide emissions are projected to be 593 million metric tons (carbon equivalent) less than the 2050 baseline projection of 2,714 million metric tons—a reduction of about 22 percent or 54 percent of the expected increase from 2005 to 2050. By 2010, the projected reduction will be about 35 million metric tons, which could provide about one-third of the targeted 2012 carbon reduction under President Bush's Climate Change Initiative.

Although not quantified here, EERE's portfolio contributes toward improved regional and local air quality through reduced SO_2 and NOx emissions from fossil energy consumption (SO_2 reductions in the utility sector are likely to lower permit prices rather than reduce net emissions in this sector). The portfolio also provides State and local governments with additional options for meeting Clean Air Act ambient air quality standards. For instance, the Clean Cities activity in the Weatherization and Intergovernmental Program facilitates local purchases of alternative-fuel vehicles.

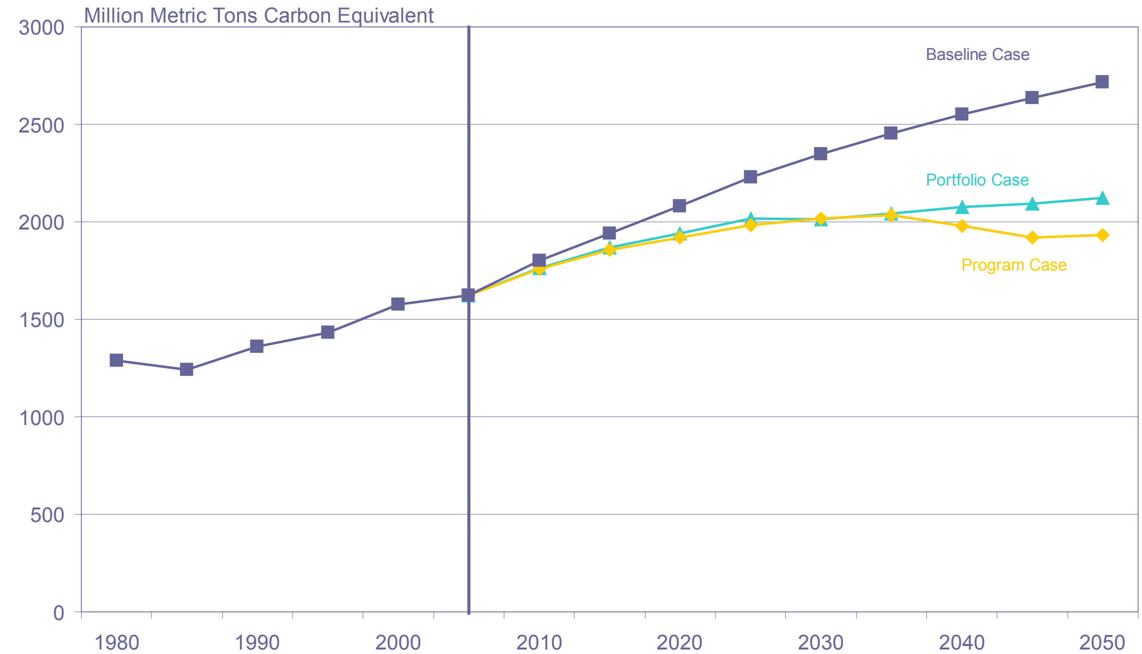

Figure 3.4. U.S. Carbon Dioxide Emissions, 1980-2000, and Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 12.2, Web site http://www.eia.doe.gov/emeu/aer/contents.html.

Security Benefits: The EERE portfolio is expected to reduce annual oil consumption by 2.1 mbpd from the 2025 baseline of 26.6 mbpd, or about 26 percent of expected growth in oil demand between 2005 and 2025 (**Figure 3.5**). The portfolio is expected to reduce oil consumption by 11.6 mbpd from the 2050 baseline of 32.5 mbpd (about 84 percent of expected growth in oil demand between 2005 and 2050). This results in declining oil consumption starting in 2030.

Figure 3.5. U.S. Oil Consumption, 1980-2000, and Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html. Data were converted from quads to mbpd using conversion factor of 1 quad = 0.472 mbpd.

While EERE's portfolio has elements that increase (as well as decrease) natural gas consumption; on balance, EERE's portfolio is expected to reduce annual natural gas consumption by about 2 quadrillion Btu from the baseline of 36 quadrillion Btu in 2025 and by 4.5 quadrillion Btu from the baseline of 46.6 quadrillion Btu in 2050 (**Figure 3.6**). While EERE does not estimate the portion of natural gas savings attributed to imported natural gas supplies, supplies from countries other than the United States and Canada may be the marginal sources of natural gas for meeting any future growth in demand.

EERE's technology programs also contribute to the security of the Nation's electricity supply by reducing central conventional power plant capacity additions. This is achieved through reduced demand for electricity (through improved efficiency or when coincident with renewable generation) and central renewable and distributed power additions. By 2025, EERE's portfolio is expected to reduce central conventional capacity additions by 157 gigawatts—by reducing demand by 40 gigawatts, and increasing central renewable and distributed power capacity by 117 gigawatts (**Figure 3.7**). As shown in **Figure 3.8**, renewable energy capacity additions (central and distributed) are projected to grow by an additional 83 GW compared with the Baseline Case in 2025, and 172 GW compared with the Baseline Case in 2050.

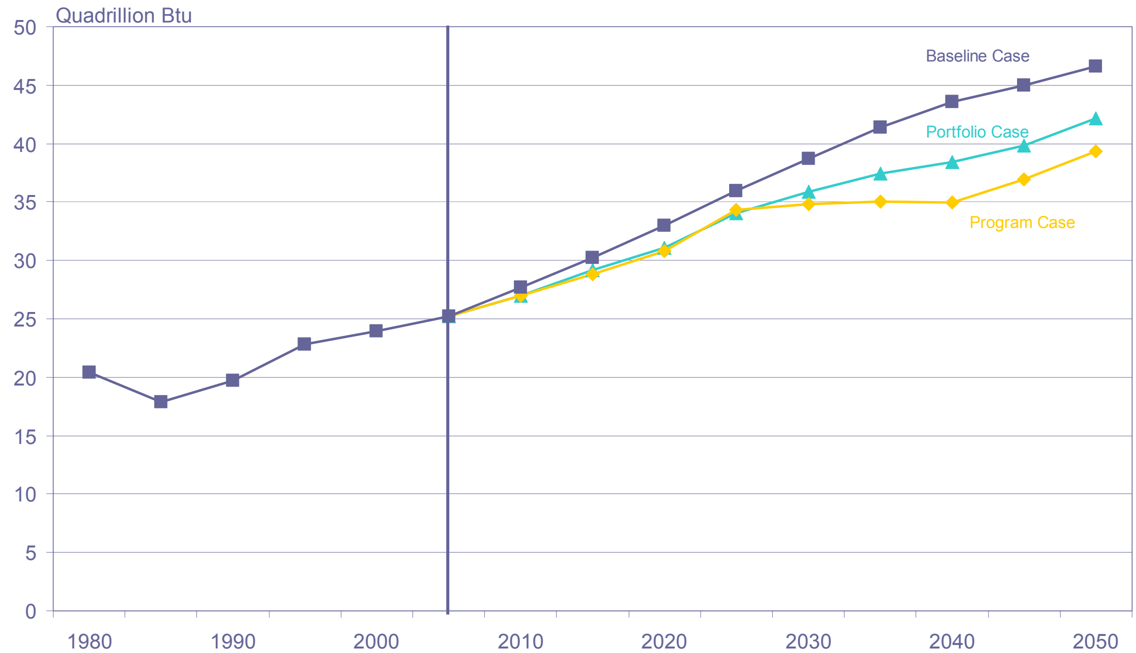

Figure 3.6. U.S. Natural Gas Consumption, 1980-2000, and Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 1.3, Web site http://www.eia.doe.gov/emeu/aer/contents.html.

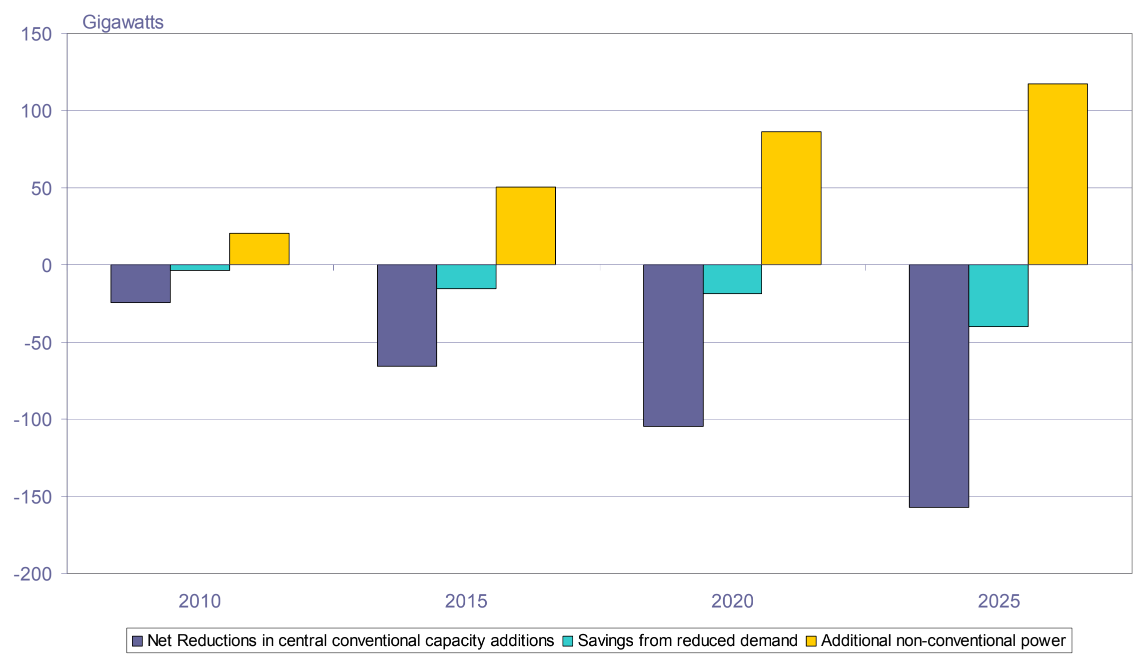

Figure 3.7. Impacts on Capacity Projections to 2025: Portfolio Case

Data Source: NEMS-GPRA05

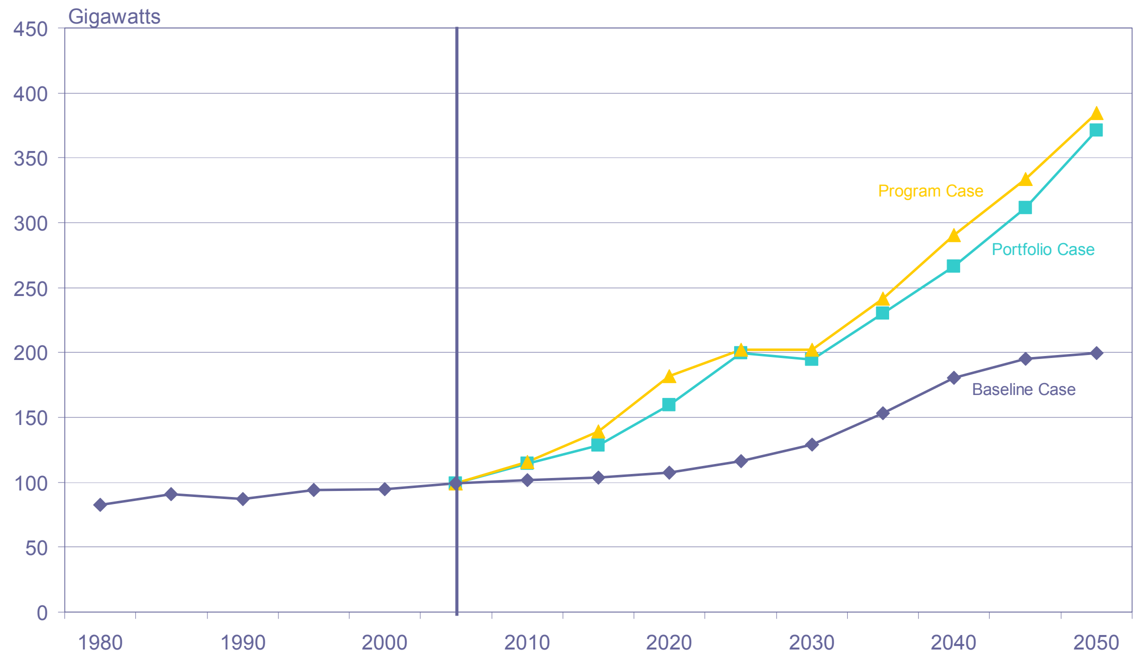

Figure 3.8. U.S. Renewable Energy Capacity, 1980-2000, and Projections to 2050: Baseline, Program, and Portfolio Cases

Data Source: 1980-2000, Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384 (2002) (Washington, D.C., October 2003), Table 8.7a, Web site http://www.eia.doe.gov/emeu/aer/contents.html.

Program Benefits

The remainder of this chapter is devoted to program-specific information, including program budget requests and benefits. See **Chapter 4** and **Chapter 5** for more specific program-level analysis. **Figure 3.9** displays the EERE program budget requests for FY 2005. The largest program budget is $348 million for the Weatherization and Intergovernmental Program (WIP), which includes $267 million for Low-Income Weatherization Assistance.

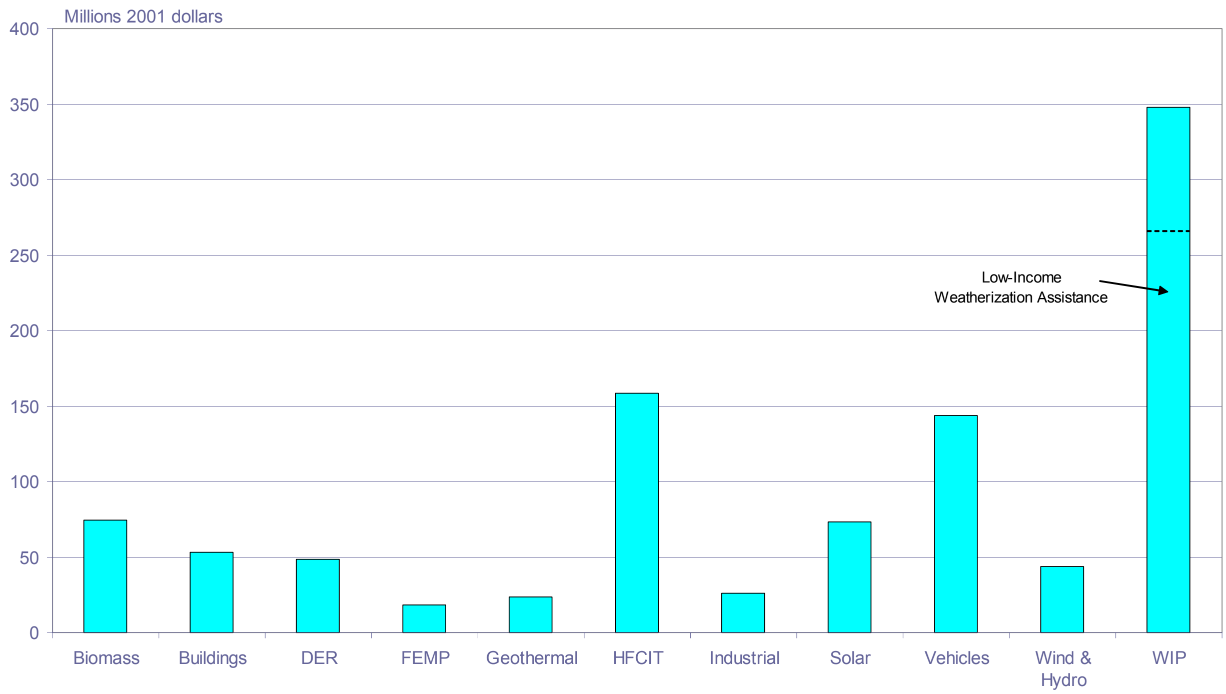

Figure 3.9. EERE Program FY 2005 Budget Requests

Source: Budget request from *FY 2005 Budget-in-Brief*, U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, http://www.eere.energy.gov/office_eere/pdfs/fy05_budget_in_brief.pdf. Figures converted to 2001 dollars using GDP implicit price deflators in *Annual Energy Outlook 2003*, Table A20.

The FY 2005 estimates of benefits for the individual EERE programs are shown for 2025 and 2050 in **Figures 3.10 through 3.16**. The benefits vary widely across EERE's programs, with each program providing a different level and mix of benefits. Often, individual programs target different types of benefits. Nonrenewable energy savings in 2025, for example, range from 0.07 quadrillion British thermal units (Btu) for the Federal Energy Management Program (FEMP) to 2.94 quadrillion Btu for the Vehicle Technologies Program (**Figure 3.10**). The differences in benefits result from a number of factors: (1) program size and target market; (2) time frames for program results and reported benefits; (3) primary types of benefits addressed by each program; (4) technical potential achievable within each program beyond the Baseline Case, and (5) ability to assess program goals or target markets with current capabilities. Note that these estimates do not reflect the relative performance risk associated with these program activities.

Several EERE programs are targeted toward benefits not well reflected in any of EERE's quantified benefits metrics. For instance, the Distributed Energy Resources (DER) Program focuses on improving electricity reliability by developing electricity-generating capacity at or near the point of use (**Figure 3.16**). However, EERE does not currently have the capability of quantifying the level or value of improved reliability, or of reflecting the consumer value for reliability in estimated future market purchases. Similarly, the State Energy Grant Program funds the development of State energy plans, including energy emergency planning. This key component of homeland security is not reflected in any of the security metrics in this analysis. In the case of the Biomass Program, there has been a substantial redirection of the research toward integrated biorefineries that will produce a mix of high-value chemicals, as well as fuels such as ethanol and electric power. These are very complex systems, and EERE does not yet have an adequate modeling capability for this, as described in **Chapters 4 and 5**.

While incomplete, the results indicate both the range and approximate level of benefits available to the Nation from funding the efficiency and renewable investments in EERE's portfolio of programs. They indicate a potential for making better use of existing technologies and for accelerating technological advances to make significant changes in our energy markets, which can drive the Nation to a period of level energy consumption.

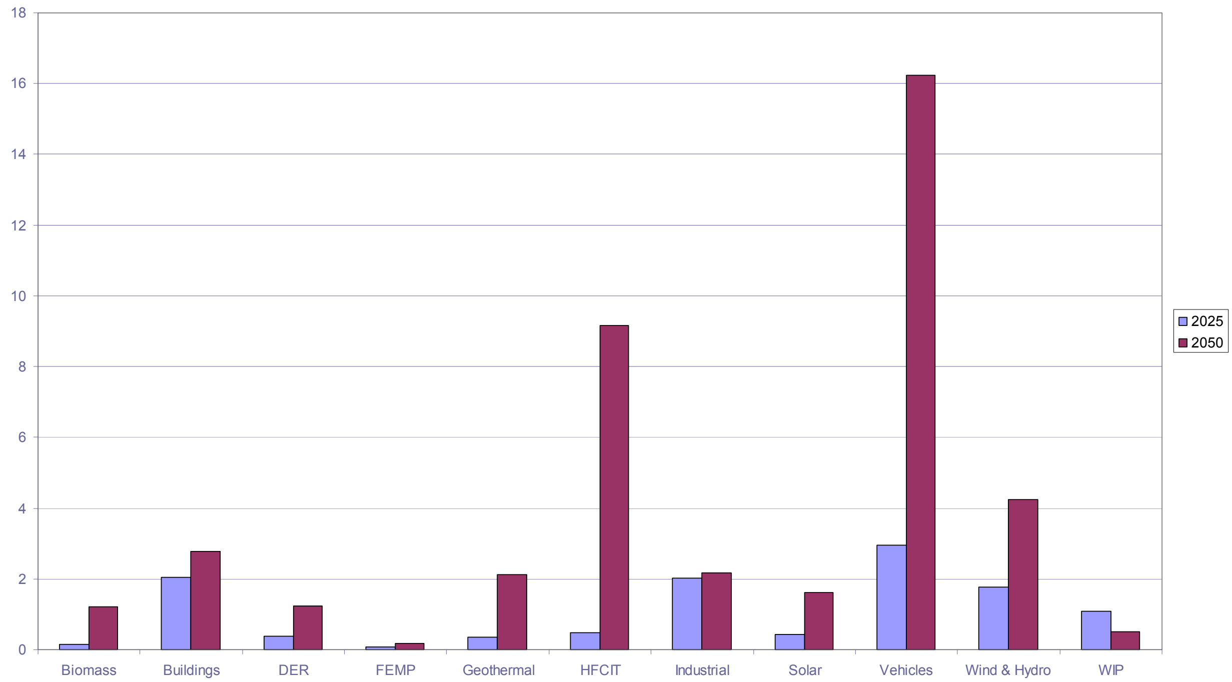

Figure 3.10. Annual Nonrenewable Energy Savings: 2025 and 2050 (quadrillion Btu)

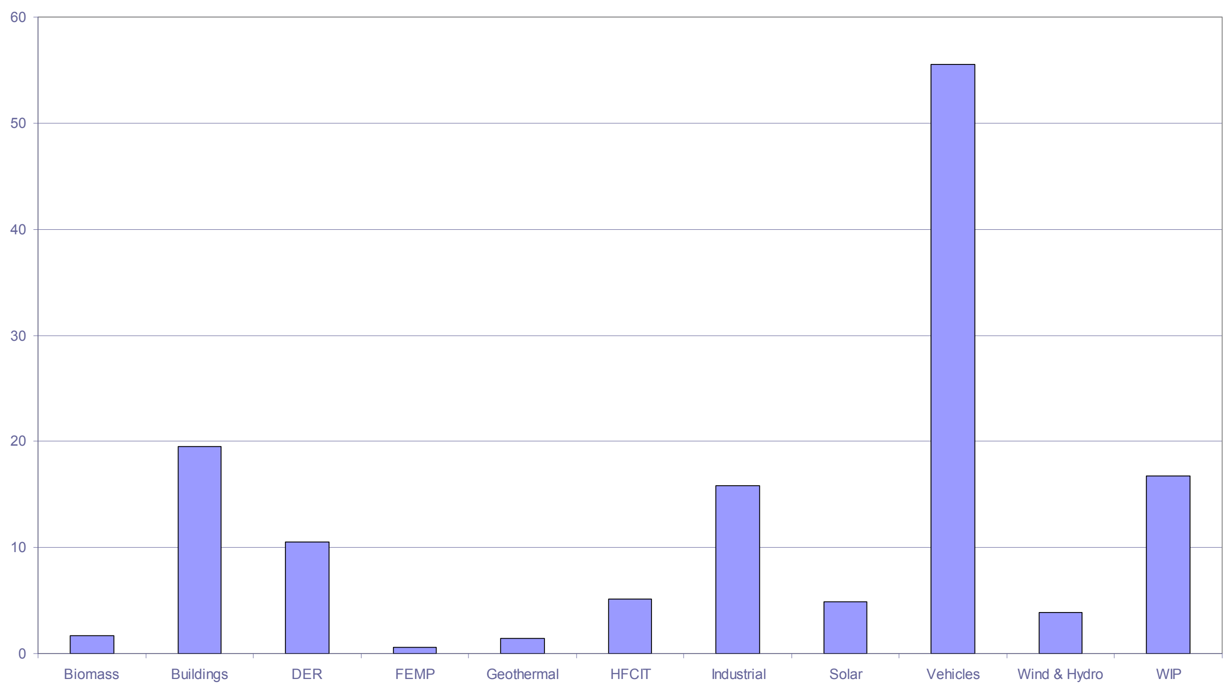

Figure 3.11. Annual Energy Expenditure Savings: 2025 (billion 2001 dollars)

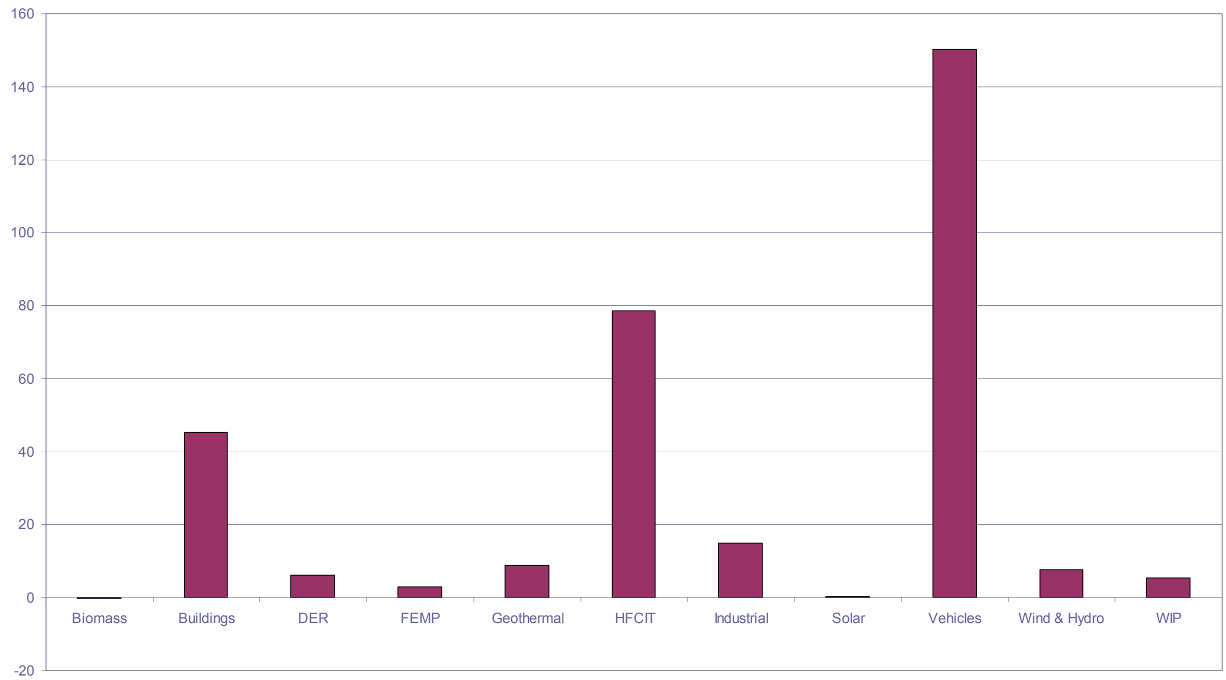

Figure 3.12. Annual Energy-System Cost Savings: 2050 (billion 2001 dollars)

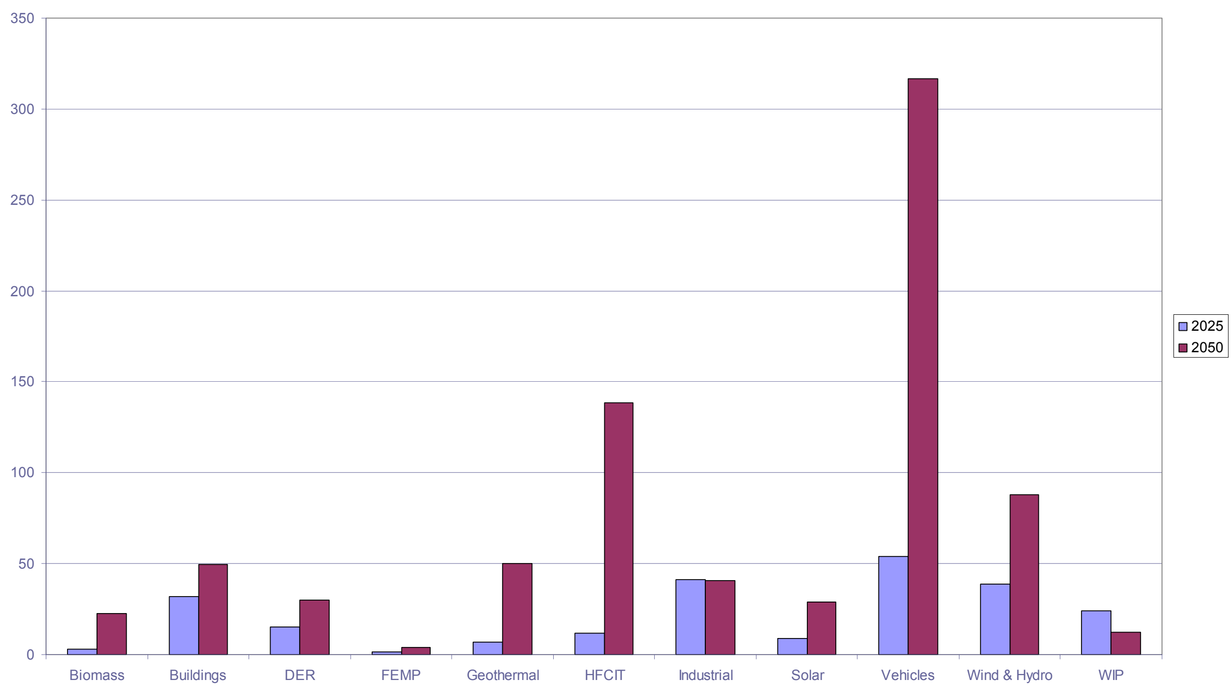

Figure 3.13. Annual Carbon Dioxide Savings: 2025 and 2050 (mmt carbon equivalent)

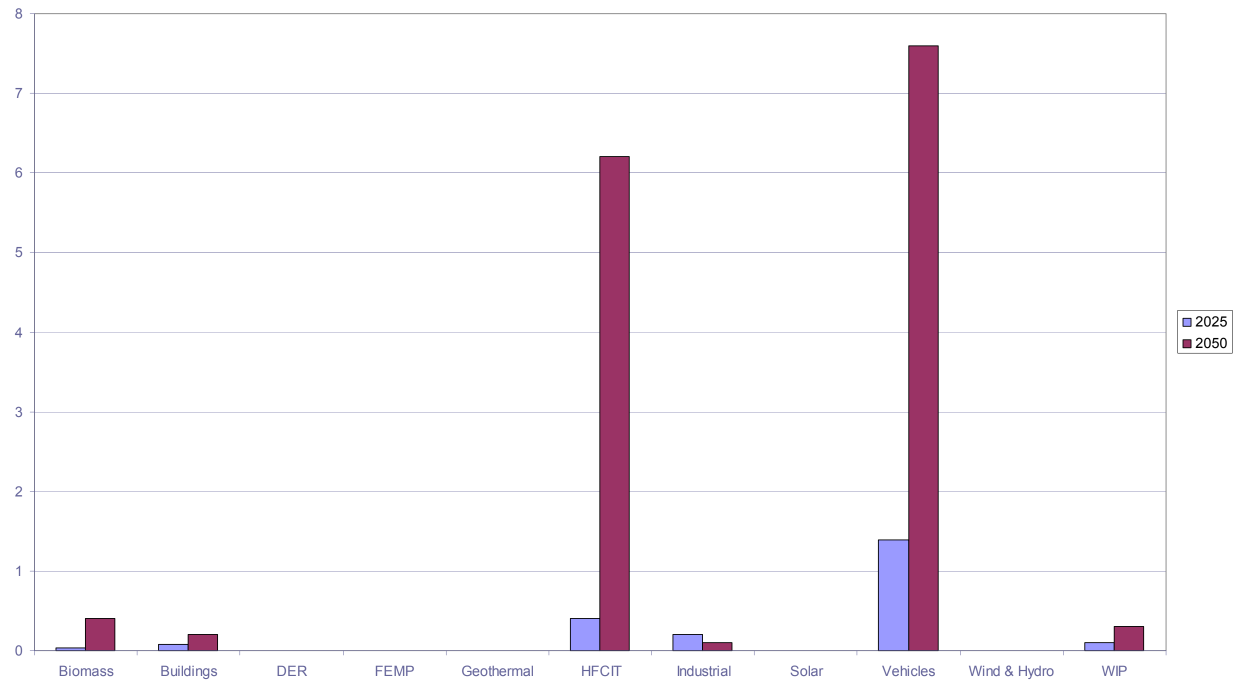

Figure 3.14. Annual Oil Savings: 2025 and 2050 (mbpd)

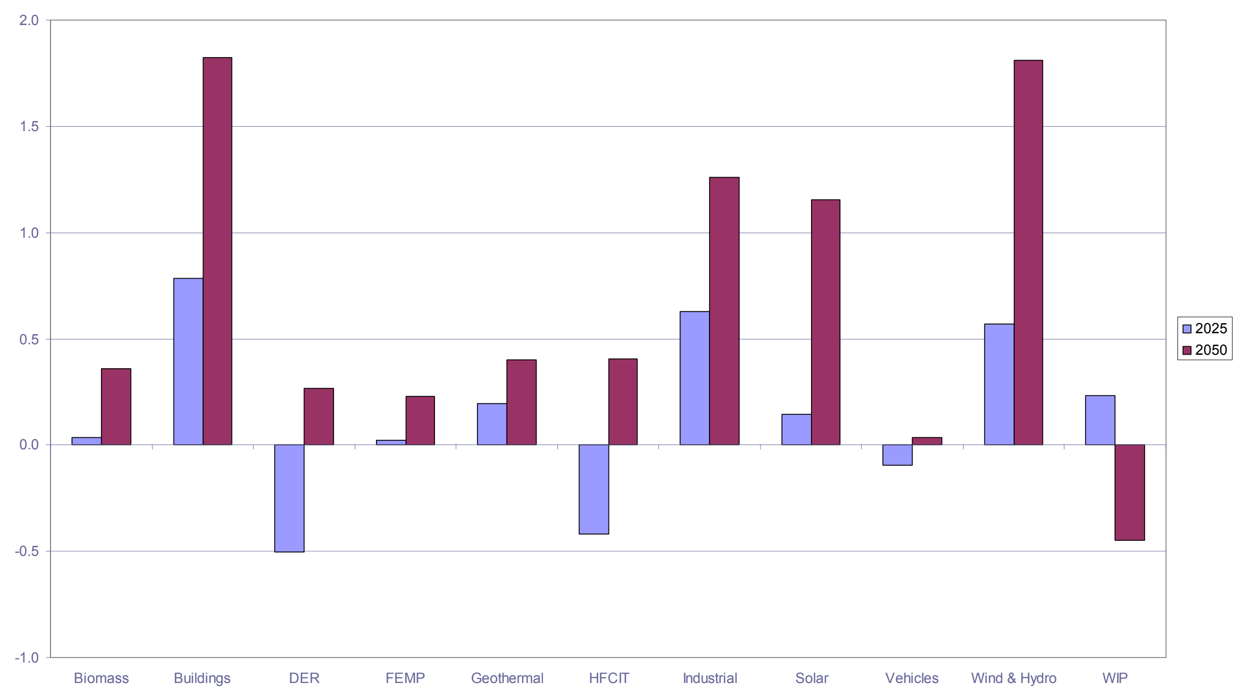

Figure 3.15. Annual Natural Gas Savings: 2025 and 2050 (quadrillion Btu)

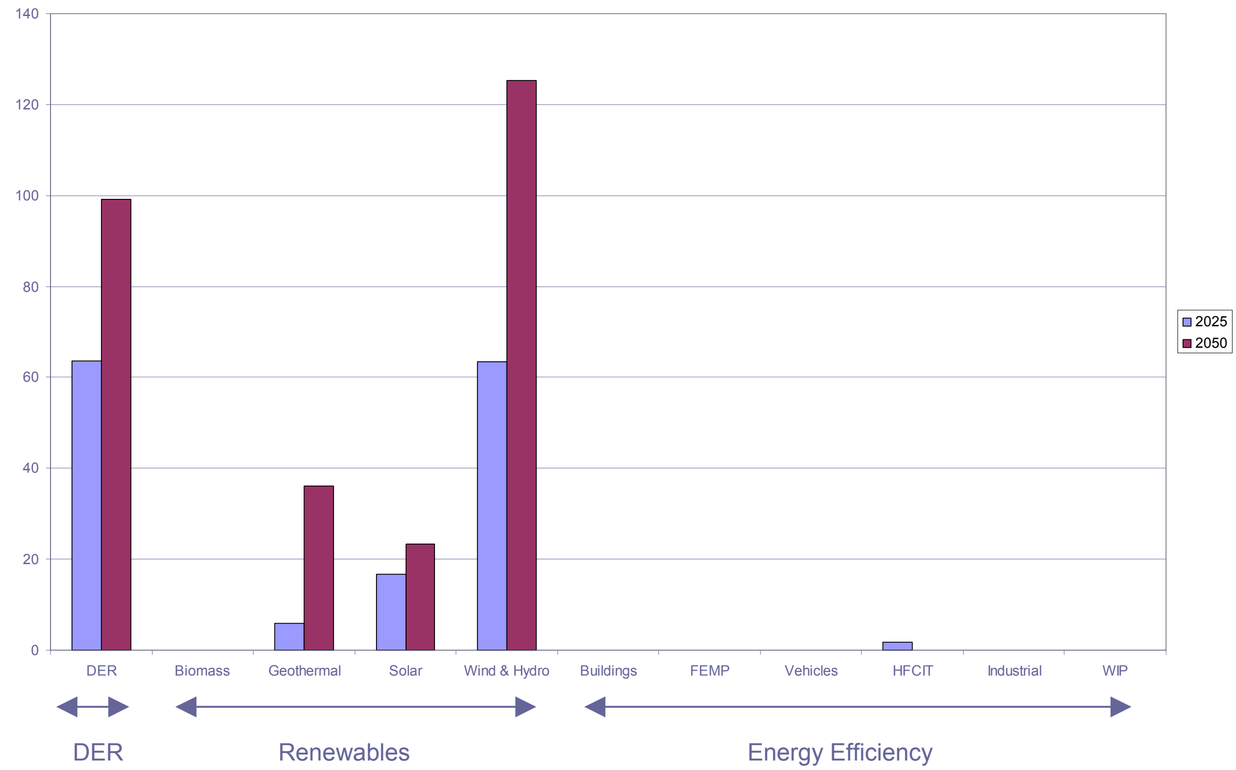

Figure 3.16. Annual Electric Generating Capacity – DER, Renewables, Energy Efficiency: 2025 and 2050 (gigawatts)

Note: Capacity for the DER Program includes gas-fired combined heat and power (CHP) systems in commercial and industrial applications and non-CHP grid support applications. Renewables include distributed and central station capacity. The Biomass Program does not create additional capacity because it is aimed at developing biomass refineries. The Buildings, FEMP, Vehicle Technologies, Industrial, and WIP programs do not create additional electric generating capacity because they are efficiency programs. Some of the efficiency programs do, however, reduce the need for additional capacity. The HFCIT Program includes fuel cell capacity.

CHAPTER 4

MIDTERM BENEFITS ANALYSIS OF EERE'S PROGRAMS

Introduction

The results of the **Step 2** program and market analyses are incorporated into NEMS-GPRA05 in the Program and Portfolio Cases to estimate the midterm (to 2025) benefits for each program and for EERE's overall portfolio. In some cases, NEMS-GPRA05 can directly utilize program performance goals (outputs). In other cases, analysts need to make adjustments to the program analyses when incorporating them in NEMS-GPRA05. This chapter describes the NEMS-GPRA05 analyses for each program. The appendices provide additional information on the inputs provided by each program.

Table 4.1 shows a breakdown by program of the two types of analytical tool employed in its benefits analyses—specialized "off-line" tools and NEMS-GPRA05. A description of EIA's NEMS model is provided in **Box 4.1** at the end of this chapter. Descriptions of the off-line tools are provided in the related program appendix.

Table 4.1. Program Benefits Modeling by Primary Type of Model Used and Activity Area

Program	Activity Area	Off-Line Tool	NEMS-GPRA05
Biomass	Bio-based Products	✓	
	Cellulosic Ethanol	✓	✓
Building Technologies	Technology R&D	✓	✓
	Regulatory Actions	✓	✓
	Market Enhancement	✓	
DER	DER		✓
FEMP	FEMP	✓	
Geothermal	Geothermal		✓
Hydrogen, Fuel Cells, and Infrastructure Technologies	Fuel Cells		✓
	Production	✓	
Industrial Technologies	R&D	✓	
	Deployment	✓	
Solar Energy Technologies	Solar Water Heaters		✓
	Photovoltaics	✓	✓
Vehicle Technologies	Light Vehicle Hybrid and Diesel		✓
	Heavy Vehicles	✓	
Weatherization and Intergovernmental	Weatherization	✓	
	Domestic Intergovernmental	✓	
Wind and Hydropower Technologies	Wind		✓
	Hydropower	✓	

Required off-line analysis can range from simple verification of program goals to an initial calculation of energy savings, depending on the treatment of the target market in NEMS-GPRA05 and the nature of the program. Analysts use specialized off-line tools to develop the inputs to NEMS-GPRA05 for each program case. The activity areas listed are groupings of activities within each program that share either technology or market features. They do not represent actual program-management categories.

Biomass Program

The goal of the Biomass Program is the development of biomass refineries, which produce a range of products including ethanol and biochemical feedstocks. This refinery approach reduces the cost of these biomass products compared to the earlier approach of individually producing each product. Unfortunately, it is currently not possible to directly model a biorefinery. Instead, analysts model individual biorefinery products (bio-based products and cellulosic ethanol) for the benefits analysis. This most likely results in an underestimation of the size of future markets and resulting benefits.

Bio-based products: The bio-based products activities seek to develop biomass-based chemical products through innovative biomass-conversion processes. The use of biomass would displace the use of petroleum and natural gas as chemical feedstocks. Because of the multitude of products and the complexity of the chemicals industry, NEMS-GPRA05 does not have sufficient detail within its representation of this industry to explicitly model bio-based products. Given the lack of a bio-based products sector in the model, analysts assessed energy savings off-line. The energy savings by fuel type (the largest share was petroleum feedstocks) were implemented in the integrated model, by subtracting the estimates from industrial energy consumption otherwise projected by NEMS-GPRA05. Analysts then used the model to compute the other benefits of primary energy savings, carbon emission reductions, and energy-expenditure savings.

Cellulosic ethanol: Cellulosic ethanol research is aimed at reducing the cost of producing ethanol from cellulosic biomass.[1] Estimates of future cellulosic ethanol production costs in the *AEO2003* and the Baseline Case are comparable. The biomass-to-ethanol conversion efficiencies for both the Baseline and Program Cases reflect more updated information than the *AEO2003* assumptions. In the *AEO2003*, EIA assumed that the growth in projected production was constrained by a number of factors in addition to ethanol production costs. In the Baseline Case, EERE was more conservative in terms of constraining the growth in ethanol production in the absence of EERE programs. EERE's biofuels analytic model, ELSAS, was used to estimate ethanol growth, with the enzyme-based technology for converting the cellulose and hemi-cellulose from the fiber contained in corn kernels will be available sooner than the related (but more complex) enzyme-based technology for converting agricultural residues to ethanol. NEMS-GPRA05 then adjusted the overall level of ethanol purchased by considering the price impacts of competing sources of demand for biomass (*e.g.*, for electricity production). Petroleum and fossil energy savings occur when the cellulosic ethanol displaces gasoline through enhanced blending. In the FY 2005 EERE benefits estimates, a large portion of the cellulosic ethanol displaces corn ethanol, which leads to fossil energy and carbon emission savings based on recent EERE life-cycle analysis. Analysts performed the adjustment for fossil energy and carbon reduction outside of NEMS-GPRA05, using results from EERE's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model.

[1] Cellulose and hemi-cellulose that can be converted to ethanol (and other chemicals, materials, and biofuels) are found in biomass such as agricultural residues (corn stover, wheat, and rice straw), mill residues, organic constituents of municipal solid wastes, wood wastes from forests, future grass, and tree crops dedicated to bio-energy production.

Table 4.2. FY05 Benefits Estimates for Biomass Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.04	0.06	0.09	0.15
Cellulosic Ethanol Production (billion gallons/yr)	0.11	0.28	0.62	1.46
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	0.0	0.0	1.2	1.7
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	0.5	0.8	1.4	2.7
Security				
Oil Savings (mbpd)	0.01	0.02	0.02	0.03
Natural Gas Savings (quadrillion Btu/yr)	0.01	0.02	0.02	0.04
Avoided Additions to Central Conventional Power (gigawatts)	ns	ns	ns	ns

Building Technologies Program

The activities of the Building Technologies Program can be classified into three general types: technology R&D, regulatory actions, and (to a far lesser extent) market enhancement.[2] The modeling approach and applicable end uses for the activities that comprise the Building Technologies Program are displayed in **Table 4.3**. Analysts model the technology R&D activities by modifying costs and efficiencies of the equipment and shell technology slates. Market-enhancement activities and some regulatory activities (such as buildings codes) are modeled using penetration rates and energy-savings estimates. A few R&D activities such as residential incandescent can light fixtures were not modeled, because they represented a small segment of the market and are not explicitly represented within NEMS-GPRA05.

Technology R&D: The technology R&D activities seek to develop new or improved technologies that are more energy efficient and more cost-effective than the alternatives currently available. The forecast benefits for these are measured by modifying the technology slates from those that are available in the Baseline Case to reflect the program goals. Building technologies in NEMS-GPRA05 are represented by end use. For most end uses, there are conversion technologies (*e.g.*, furnaces and water heaters) that use different fuels and that have several different levels of energy efficiency. The Baseline Case incorporates EIA's estimation of future technology improvement that is then modified in the Program Case.

Residential shell technologies, such as windows or insulation, are represented by several packages of technologies with different levels of improvements. Each package is characterized by a capital cost and heating and cooling load reductions. The commercial-sector shell measures are represented by window and insulation technologies that can be selected individually. EIA developed the residential methodology for the *AEO2001*, while OnLocation developed the commercial methodology for EERE.

[2] With the reorganization of EERE, the overwhelming majority of the market-enhancement activities are part of the Weatherization and Intergovernmental Program.

Table 4.3. Modeling Approach for Building Technologies Program Activities

Building Technology Project List	Sector		End-Use					Modeling Approach		
	Resd	Comm	Heat	Cool	Water Heating	Lighting	Other	Energy Savings and Penetration Rates	Equipment Technology Costs and Efficiencies	Shell Technology Costs and Efficiencies
Residential Buildings Team										
Residential Energy Codes	✓		✓	✓				✓		
Technology Research and Development	✓		✓	✓	✓	✓	✓			✓
Commercial Buildings Team										
Commercial Energy Codes		✓	✓	✓		✓		✓		
Technology Research and Development		✓	✓	✓				✓		
Building Equipment Team										
Equipment Standards and Analysis										
EPAct Standards		✓	✓	✓					✓	
Emerging Technologies Team										
Analysis Tools and Design Strategies		✓	✓	✓				✓		
Appliances and Emerging Techn. R&D										
Heat Pump Water Heater	✓				✓				✓	
Roof top AC		✓		✓					✓	
Incandescent Can Light Fixtures	✓					✓				
R-Lamp	✓					✓				
Envelope Research and Development										
Electrochromic Windows		✓	✓	✓		✓				✓
Superwindows/Low-e Windows	✓		✓	✓				✓		✓
Lighting Research and Development										
Lighting Controls		✓				✓		✓		
Next Generation Lighting	✓	✓				✓			✓	
Space Conditioning and Refrigeration R&D										
HVAC Distribution System		✓	✓	✓				✓		
Advanced Electric HPWH	✓								✓	
Commercial Refrigeration										
Refrigerant Meter		✓	✓	✓						✓

The residential and commercial sectors are each represented by several building types within nine Census divisions. NEMS-GPRA05 computes end-use technology choice for each of these building types and geographic regions, based on the relative economics and estimations of consumer behavior for the technologies. The latter is important to replicate current technology market shares.

Improved EERE technologies that have no incremental costs above the baseline technologies must be treated differently. If they were introduced into the modeling framework as technologies with zero incremental costs, there would be immediate adoption and unrealistic market shares. Thus, for these activities, program penetration estimates developed off-line are used to compute a target savings.[3] These savings were achieved in NEMS-GPRA05 by lowering the consumer

[3] The target savings, however, are first reduced by 5 percent to 50 percent, as are other program estimates that cannot be modeled within NEMS-GPRA05. These percentages were based on the extent of overlap with other program activities. The revision is based on the expert judgment of the benefits analysis team.

hurdle rates for the appropriate end uses or by modifying the autonomous shell efficiency indices.

Regulatory activities: Regulatory activities include setting new appliance standards, based on the legislatively mandated schedule and encouraging state adoption of more stringent building codes.[4] Representing appliance standards is straightforward. In the year that the program expects the new standard to be implemented, all technologies that are less efficient than the standard are removed from the market and unavailable for consumer choice. The resulting energy savings depend on the difference in the level of efficiency of the standard compared to the technology that had been selected in the Baseline Case.

Market enhancement: Building-code development is primarily a regulatory activity, although it also involves outreach to encourage the various states to adopt new and stricter standards. Analysts make a spreadsheet computation of average savings using off-line estimates for the fraction of buildings within areas that adopt more stringent codes, as well as the heating, cooling, and lighting load reductions associated with the new levels of codes. The building shell packages are modified to produce the appropriate savings.

The Building Technologies Program results in energy savings primarily in four end-use categories: space heating, space cooling, water heating, and lighting. **Table 4.4** demonstrates the level of savings from each category. In 2025, lighting energy-use reduction is the largest share of the total savings in both the residential and commercial sectors. Space heating and cooling also show significant savings. Water-heating savings occur only in the residential sector.[5]

Table 4.4. Building Technologies Program Energy Savings by End Use

Energy Reduction Percentage	Residential				Commercial			
	2010	2015	2020	2025	2010	2015	2020	2025
Space Heating	1%	3%	5%	6%	2%	4%	5%	7%
Space Cooling	0%	1%	2%	4%	2%	5%	7%	9%
Water Heating	3%	5%	5%	6%	0%	0%	-1%	-1%
Lighting	0%	0%	1%	16%	1%	2%	8%	16%
Other	0%	0%	0%	0%	0%	0%	0%	0%

Analysts estimate the Building Technologies Program benefits (**Table 4.5**) within the integrated NEMS-GPRA05, so that the electricity-related primary energy savings are directly computed. In addition, the estimates include any feedbacks in the buildings or other sectors resulting from changes in energy prices that result from the reduced energy consumption.

[4] The outreach/deployment aspects of the codes process occur with funding provided by the Weatherization and Intergovernmental Program.
[5] The very small increase in commercial water-heating consumption (shown as a negative savings in Table 4.4) stems from a response to lower energy prices. The lower energy prices result from reduced energy consumption in buildings and other sectors.

Table 4.5. FY05 Benefits Estimates for Building Technologies Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.33	0.66	1.12	2.03
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	4	10	16	27
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	6	13	22	43
Security				
Oil Savings (mbpd)	0.02	0.03	0.04	0.08
Natural Gas Savings (quadrillion Btu/yr)	0.15	0.33	0.54	0.78
Avoided Additions to Central Conventional Power (gigawatts)	3	8	16	26
Total Electricity Capacity Avoided (gigawatts)	5	10	21	36

Distributed Energy Resources Program

The Distributed Energy Resources (DER) Program encompasses many technologies and markets. The benefits were estimated by focusing on several segments of the distributed energy market: gas-fired combined heat and power (CHP) systems in commercial building and industrial applications, and non-CHP grid support applications. Distributed energy resource applications that are motivated by the need for electric reliability primarily will be systems that produce only electricity and are used in backup mode. In the program analysis, these are represented as grid-support DER for their similar technology characteristics, although the model treats them as though they are purchased by electric-power producers rather than electricity-consuming businesses. The value of these systems is difficult to capture in the GPRA benefits metrics. They do not provide significant energy or emissions savings, because they run for only a few hours per year and generally have similar or lower efficiencies than larger central-station peaking facilities. They do have the potential to contribute significantly to new electric power-generating capacity. The benefit estimates do not account for increased reliability and local Clean Air Act impacts on demand.

Combined heat and power systems produce both useful thermal heat and electricity. Their economics depend on the amount of thermal heat needed at the site, the electricity usage at the site, the price of the input fuel, and the value of the electricity. If the end-use customer is making the investment, the electricity value will depend on the customer-avoided purchases at the electricity retail price, and possibly the amount of excess electricity sold off-site at prevailing wholesale electricity prices. Using the average electricity price is a simplification that may overlook the requirement to continue paying some type of flat distribution charge, even though less electricity is purchased from the utility. If a vertically integrated electric utility is making the investment, the value is from avoided generation, and transmission and distribution (T&D) costs. The distributed systems would be placed strategically in the grid to avoid T&D expansion costs.

The DER Program facilitates the development of the DER market by improving the technology characteristics (lowering costs, improving efficiency, and reducing environmental emissions) and by removing barriers to adoption and consumer acceptance. Thus, the benefits are estimated based on the impact of improved technology and greater market penetration.

Baseline adjustments: The *AEO2003* Reference Case includes significant DER technological advancement. The Baseline Case included a modified set of technology characteristics that represented the absence of continued EERE programs. These modifications were made in all three areas in NEMS where distributed technologies are represented: commercial building combined heat and power (CHP), industrial CHP, and utility grid support. The technology assumptions for commercial gas-fired chillers also were modified, and these chillers were assumed to be applicable to all building types; unlike in the *AEO2003,* where they can be used only in the larger building sizes.

The adoption rates of distributed technologies in commercial buildings were modified to reflect market data gathered by EERE on consumer adoption of energy efficiency projects as a function of payback time (**Figure 4.1**).[6] The NEMS-GPRA05 framework uses a cash-flow model to evaluate the DER technologies—CHP and photovoltaic (PV) systems—within the building sectors. For commercial buildings, debt and interest payments are computed over a loan period of 20 years along with associated taxes and tax benefits and assuming a 20 percent down payment. Annual fixed maintenance costs also are included. For the gas-fired CHP technologies, NEMS-GPRA05 computes fuel costs based on the delivered cost of natural gas and the technology efficiency. The value of the useful waste heat produced is netted against the fuel cost, based on the delivered natural gas price, the thermal efficiency of the CHP system, and the internal thermal load. The value of the electricity produced is then subtracted from these costs to determine the cash flow. The value of electricity is equal to the larger of the electricity produced and the internal electricity demand, multiplied by the delivered electricity price. Any electricity produced in excess of internal needs is assumed to be sold to the grid at the wholesale rate. The number of years until positive cash flow is reached determines the market share in new buildings. The market share for existing buildings is assumed to be a fraction of the share for new.

Under both the EIA and program assumptions, market share in new buildings decreases sharply as the number of years required to achieve positive cash flows increases. This reflects the high rates of return generally expected for energy-related projects by commercial-building owners. These shares apply to the fraction of commercial buildings assumed to be eligible for an installation of distributed CHP. The *AEO2003* eligibility fraction assumption of 30 percent was increased to 50 percent. These adoption rate changes were made in the Baseline Case as well as the Program Case.

Technology improvements: The program provided characteristics for distributed energy systems that reflect the program's research goals. These included commercial CHP systems (gas engines, gas turbines, gas micro turbines), commercial gas-fired chillers, industrial CHP (five systems sizes for gas-fired engines and turbines), and grid-support DER (base and peaking).

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[6] ***Market Trends in the U.S. ESCO Industry: Results from the NAESCO Database Project***. Goldman, C., J. Osborn and N. Hopper, LBNL, and T. Singer, NAESCO, May 2002, LBNL-49601.

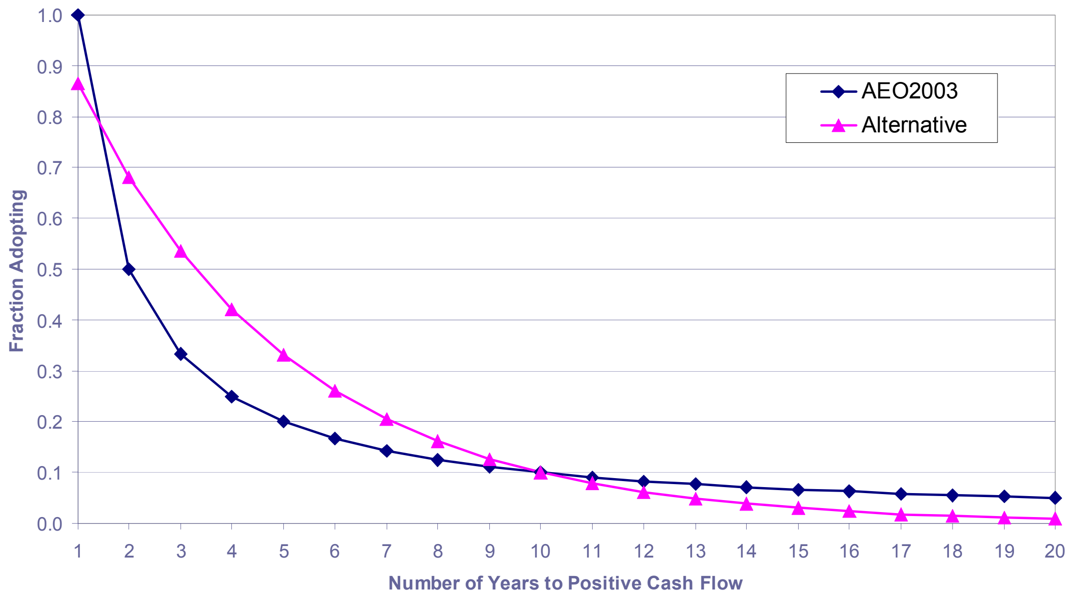


Figure 4.1. Commercial-Sector DG Adoption Rates

Market enhancement: The DER Program's impact on consumer-adoption rates was represented primarily for smaller distributed energy in commercial buildings. As described previously, the DER market share for the existing building stock in NEMS-GPRA05 is tied to the market share computed for new buildings. The baseline (and *AEO2003*) assumption is that the fraction of existing buildings that will adopt DER in a given year is one-fiftieth of the share for new buildings. For the Program Case, this was accelerated to one-tenth each year. Note that the adoption rate for the existing stock of buildings is considerably smaller than the market share for new buildings, reflecting that the entire existing stock will not make investments in distributed technologies as quickly as the increment that is built each year. Although the DER program does not impact PV technology performance, the rate of adoption of Baseline Case PV accelerates. This is due to the market-enhancement activities, as represented by the increased adoption rates in existing buildings. This share would likely grow if modeled in conjunction with the Solar Energy Technologies Program PV technology improvements.

The incremental DER capacity that results from this representation of the DER Program activities is shown in **Table 4.6**, along with the projected total quantities. Of the 64 GW of incremental capacity by 2025, more than 75 percent of the increase is expected from commercial-building applications, roughly 5 percent from generally larger industrial applications, and the remaining from grid-support systems.

In the Baseline Case, by 2025, the commercial sector is projected to satisfy roughly 3 percent of its total electricity demand with distributed generation, and the industrial sector 16 percent. With the DER Program, the share increases to 18 percent in the commercial sector and 17 percent in the industrial sector.

Table 4.6. Distributed Energy Resources Capacity (GW)

	2005	2010	2015	2020	2025
AEO Base					
Buildings	1.2	1.5	1.7	2.4	3.7
Industry*	29.9	33.1	35.9	39.2	43.8
Electric Industry	0.3	1.7	5.1	10.1	15.9
Baseline Case					
Buildings	1.8	1.9	2.3	5.5	15.1
Industry*	29.8	32.9	35.5	38.7	42.9
Electric Industry	1.8	8.6	18.6	32.9	55.6
Benefits Case					
Buildings	2.3	6.9	17.1	33.8	64.0
Industry*	29.9	33.1	35.9	39.7	46.1
Electric Industry	2.5	17.4	37.9	51.9	67.0
Incremental Capacity					
Buildings	0.5	5.1	14.8	28.3	48.9
Industry*	0.1	0.2	0.4	1.0	3.2
Electric Industry	0.8	8.8	19.3	19.0	11.5
Total	1.4	14.1	34.5	48.3	63.6

* Excludes nontraditional, large qualifying facility cogenerators.

The DER Program benefits (**Table 4.7**) are projected within the integrated modeling framework, so that the impact of the program will be reflected in the rest of the energy system. As a result of increased investments in DER, electricity purchases from the commercial and industrial sectors are reduced, and additional electricity is sold wholesale to the grid.

Table 4.7. FY05 Benefits Estimates for DER* (NEMS-GPRA05)

Benefits	**2010**	**2015**	**2020**	**2025**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.03	0.08	0.23	0.38
Generation (gigawatt-hours/yr)	28	102	194	315
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	2	3	7	11
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	1	6	10	15
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	-0.06	-0.30	-0.35	-0.50
Avoided Additions to Central Conventional Power (gigawatts)	11	38	55	80
Program-Specific Electric Capacity Additions (gigawatts)	14	35	48	64

* Includes increased market penetration for stationary fuel cells.

The central electricity-generation industry responds by reducing production from the most expensive plants operating in each region, and over time by building fewer central-station plants in the face of lower demand. Retirements are relatively unaffected, with only 6 GW of additional capacity retired by 2025 in the Program Case. Roughly 80 GW of central-station investments are avoided by the additional DER. In the Baseline Case, about 70 percent of new central-station capacity additions from 2005 to 2025 are projected to be natural gas fired, and about 80 percent of the avoided central-station investments are natural gas-fired turbines and combined-cycle plants. In 2025, roughly 65 percent of the avoided central generation is gas fired. In total, distributed generation makes up roughly 24 percent of new capacity additions from 2005 to 2025 in the Baseline Case. This share increases to 45 percent in the Program Case.

The energy- and carbon emission-reduction benefits that stem from distributed generation are computed as the decrease in traditional central-station nonrenewable energy consumption and associated carbon emissions, net of the energy and emissions from the DER. The central-station generation reductions are from a mix of existing plants and avoided new plants. Over time, the facilities that are used in the Baseline Case become more efficient as the gas combined-cycle and combustion turbine technologies continue to improve. As a result, the energy and emission savings from the central grid decline per kilowatt-hour.

Federal Energy Management Program

The Federal Energy Management Program (FEMP) is an implementation program to increase the energy efficiency of Federal Government buildings, which account for about 5 percent of U.S. commercial-building energy consumption. FEMP activities support the installation of a variety of existing technologies, rather than focusing on the development of specific technologies, as do many other EERE programs. Because it encompasses a broad technological scope—while, at the same time, targeting a specific market segment—FEMP is difficult to model in an integrated framework such as NEMS-GPRA05. However, there is also less uncertainty associated with achieved energy savings because the program tracks changes in Federal energy consumption.

Delivered energy savings (estimated off-line) are used as inputs for the integrated modeling. These projected savings are subtracted from the Baseline Case for commercial-building energy consumption. Analysts use the model to compute the other benefits metrics of primary energy savings, carbon emission reductions, and energy expenditure savings (**Table 4.8**).

Table 4.8. FY05 Benefits Estimates for FEMP (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Non-Renewable Energy Savings (quadrillion Btu/yr)	0.03	0.04	0.05	0.07
Economic				
Energy Expenditure Savings (billion 2001 dollars/yr)	0.2	0.3	0.5	0.6
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	0.5	0.8	1.1	1.5
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.02	0.02	0.02	0.02
Avoided Additions to Central Conventional Power (gigawatts)	0	0	1	1

Geothermal Technologies Program

The primary goal of the Geothermal Technologies Program is to reduce the cost of geothermal-generation technologies, including both conventional and enhanced geothermal systems (EGS). Measuring the benefits involves projecting the market share for these technologies, based on their economic and environmental characteristics.

The NEMS-GPRA05 electricity-sector module performs an economic analysis of alternative technologies in each of 13 regions. Within each region, new capacity is selected based on its relative capital and operating costs, its operating performance (*i.e.*, availability), the regional load requirements, and existing capacity resources. Geothermal capacity is treated in a unique manner, due to the specific geographic nature of the resources. The model characterizes 51 individual sites of known hydrothermal geothermal resources, each with a set of capital and operating and maintenance (O&M) costs. For the Program Case, an additional set of EGS sites were added to this slate.

The Geothermal Program was represented by reducing the capital and O&M costs for all hydrothermal geothermal sites, so that the average of the three lowest-cost sites matched the program cost goals, as reflected in the EERE/EPRI *Renewable Energy Technology Characterizations* report.[7] Separate program technology goals were provided for the added EGS sites. In addition, the program was assumed to reduce the risk associated with new geothermal development, and the Baseline Case limit on the size of annual developments per geothermal site was increased from 25 MW or 50 MW (depending on year) to 100 MW per year.

In addition to competing on an economic basis with other electricity-generation technologies, geothermal capacity may be constructed for its environmental benefit. Princeton Energy Resources International (PERI), using their Green Power Market Model, provided an estimate of geothermal capacity additions in response to the expanding green power markets in many places throughout the country. The projections for green power geothermal installations were incorporated into NEMS-GPRA05 as planned capacity additions.

Table 4.9 shows the resulting additional geothermal capacity and generation, by region and for capacity by technology type. The greatest incremental capacity is in California (CAL) and the Northwest (NWP), with less in the Rocky Mountain area (RA).

The primary energy, oil, and carbon emissions savings stem from geothermal power displacing fossil-fueled generation sources. Energy-expenditure savings are measured as the reduction in consumer expenditures for electricity and other fuels. Lower-cost renewable generation options reduce the price of electricity directly and reduce the pressure on natural gas supply, both of which benefit end-use consumers. **Table 4.10** shows the overall Geothermal Technologies Program benefits.

[7] EERE/EPRI (1997). *Renewable Energy Technology Characterizations*. EPRI-TR-109496.

Table 4.9. Geothermal Capacity and Generation

	2010	2015	2020	2025
GPRA Base Capacity (GW)				
NWP	1.0	1.5	2.2	2.6
RA	0.4	0.4	0.4	0.5
CAL	2.6	2.7	3.0	3.2
Total	3.9	4.6	5.7	6.3
Conventional	3.9	4.6	5.7	6.3
EGS	0.0	0.0	0.0	0.0
Program Case Capacity (GW)				
NWP	2.6	3.4	3.8	4.6
RA	0.4	0.7	0.8	1.3
CAL	3.5	4.0	5.3	6.3
Total	6.5	8.2	10.0	12.2
Conventional	6.5	8.2	8.7	8.8
EGS	0.0	0.0	1.2	3.4
Total	6.5	8.2	10.0	12.2
Incremental Capacity (GW)				
NWP	1.6	1.9	1.6	2.0
RA	0.1	0.3	0.4	0.8
CAL	0.9	1.4	2.3	3.0
Total	2.6	3.6	4.3	5.8
Conventional	2.6	3.6	3.0	2.4
EGS	0.0	0.0	1.2	3.4
Total	2.6	3.6	4.2	5.8
Incremental Generation (BkWh)				
NWP	12	16	13	16
RA	1	2	3	6
CAL	7	11	18	24
Total	20	29	35	46

Table 4.10. FY05 Benefits Estimates for Geothermal Technologies Program (NEMS-GPRA05)

Benefits	**2010**	**2015**	**2020**	**2025**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.15	0.17	0.23	0.35
Generation (gigawatt-hours/yr)	20	29	35	46
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	0.6	1.6	1.8	1.5
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	2.7	2.3	4.1	6.7
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.08	0.18	0.16	0.20
Avoided Additions to Central Conventional Power (gigawatts)	2	2	4	5
Program-Specific Electric Capacity Additions (gigawatts)	3	4	4	6

Hydrogen, Fuel Cells, and Infrastructure Technologies Program

The Hydrogen, Fuel Cells, and Infrastructure Technologies Program is targeted toward the introduction of fuel cells for both stationary and vehicular applications, as well as the production and delivery of hydrogen at a reasonable price. NEMS-GPRA05 does not have a representation of hydrogen supply options. Therefore, a simple assumption was used that all hydrogen through 2025 would be derived from natural gas. The hydrogen conversion process was assumed to be 75 percent efficient and yield a hydrogen price of $1.50 per gallon of gasoline equivalent (excluding taxes) when the natural gas price is $4 per MMBtu.

The stationary fuel cell research is focused on distributed proton-exchange membrane (PEM) fuel cells. The program goals for their capital costs and efficiencies were taken from the multiyear program plan (MYPP). The MYPP provides goals through 2010, and no further improvements were assumed. This conservative assumption most likely understates the benefits of these fuel cells.

The fuel cell vehicles were modeled along with the Vehicle Technologies Program. The success of fuel cell vehicles is predicated on some of the vehicular improvements being developed under the Vehicle Technologies Program, so the fuel cell vehicles could not be treated in isolation. Analysts modified the gasoline and hydrogen fuel cell vehicle costs and efficiencies to reflect the program goals (see the Vehicle Technologies Program description for more detail about the modeling of vehicle choice). In addition, hydrogen availability for vehicle refueling was assumed to be 10 percent by 2020 and 25 percent by 2025. The benefits associated with fuel cell vehicles were derived by comparing the amount of fuel cell vehicles from the case with "both Hydrogen and Vehicle Technologies" to the "Vehicle Technologies only" case. Analysts computed energy savings, oil savings, and carbon emission reductions, based on the incremental fuel cell vehicles assuming conventional gasoline vehicle displacement (**see Figure 4.2**). This leads to greater savings than a simple difference between the cases, while still having smaller savings than would be derived by comparing a fuel cell vehicles case with the Baseline Case. **Table 4.11** presents the overall benefits.

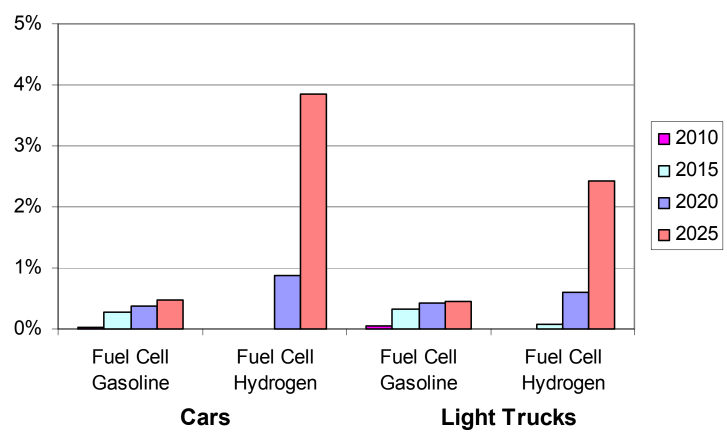


Figure 4.2. Vehicle Shares

Table 4.11. FY05 Benefits Estimates for Hydrogen, Fuel Cells, and Infrastructure Technologies Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.01	0.06	0.14	0.49
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	0.0	0.3	1.3	5.2
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	0.0	1.3	3.6	11.8
Security				
Oil Savings (mbpd)	ns	ns	0.10	0.40
Natural Gas Savings (quadrillion Btu/yr)	ns	ns	-0.13	-0.42
Avoided Additions to Central Conventional Power (gigawatts)	0	0	1	0
Program-Specific Electric Capacity Additions (gigawatts)	0	1	2	2

Industrial Technologies Program

The Industrial Technologies Program covers primarily the energy-intensive basic materials processing industries, as well as some key technologies that are common across most industries, with the objective of increasing energy efficiency. These can be characterized in two categories, R&D and deployment. The R&D projects generally apply to specific industries or to specific technologies that cut across industries. The R&D projects seek to develop new or improved technologies that are more energy efficient and more cost-effective than the alternatives currently available. The deployment projects seek to increase the adoption of existing, as well as new, energy-efficient technologies.

The heterogeneity of the program makes it difficult to represent the program activities explicitly through technologies in the NEMS-GPRA05 framework. Therefore, analysts perform an off-line analysis using detailed spreadsheet models, and use the resulting energy savings by fuel type to provide inputs into the integrated model. Because these programs cannot be modeled on an economic basis, analysts reduce the off-line energy savings by an "integration factor" before putting them into NEMS-GPRA05. This is to account for interactions among programs and feedback effects that could not be considered in their original estimation. The amount of the integration factor is based on how much program overlap or "integration" was captured by the off-line tools. The reduction is based on the expert judgment of the benefits analysis team. The three basic types of industrial programs were treated somewhat differently. Analysts reduced the Industries of the Future programs only 15 percent, because they are relatively specific and the least likely to experience overlap with other industrial programs. The crosscutting programs were reduced by 30 percent. The Best Practices activity initially was reduced by 50 percent. However, the program revised the Best Practices savings estimate, and the equivalent final reduction is roughly 35 percent.

Analysts then run the fully integrated NEMS-GPRA05 to compute the benefits metrics of primary energy savings, carbon emission reductions, and energy-expenditure savings that are associated with the fuel-consumption reductions.

The resulting estimated primary savings are slightly lower than those targeted because of feedback effects that come through the integration with other sectors. The primary feedback effect occurs through lower fuel prices. In this case, the lower energy consumption causes lower energy prices (although the feedback is small), which causes energy consumption to be higher than it otherwise would have been, leading to slightly lower program savings (**Table 4.12**).

Table 4.12. FY05 Benefits Estimates for Industrial Technologies Program (NEMS-GPRA05)

Benefits	**2010**	**2015**	**2020**	**2025**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.48	0.92	1.56	2.02
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	4.6	10.3	16.6	15.8
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	9.0	17.7	29.8	41.4
Security				
Oil Savings (mbpd)	0.10	0.10	0.10	0.20
Natural Gas Savings (quadrillion Btu/yr)	0.19	0.39	0.71	0.63
Avoided Additions to Central Conventional Power (gigawatts)	2	3	8	13
Total Electric Capacity Avoided (gigawatts)	3	2	8	15

Solar Energy Technologies Program

The Solar Energy Technologies Program develops both thermal-heat and electric-solar technologies. The solar water-heating component is focused on developing low-cost solar hot water and pool heaters to displace fossil-fueled or electric alternatives. For electricity generation, photovoltaics (PVs) are being improved for both distributed and central generation applications, and the program is working to accelerate PV adoption through the Million Solar Roofs Initiative. Concentrated Solar Power R&D also has been part of the Solar Energy Technologies Program, but is not included in the FY05 budget request. As a result, concentrated solar power has not been included in the GPRA05 benefits estimates.

The benefits for solar water heat are represented within the residential module of NEMS-GPRA05. The solar water heater is a specific technology defined by its capital cost, O&M costs, and electrical use. NEMS-GPRA05 was modified to add solar water heat as an option for new homes, and the algorithm governing water-heater replacements was modified so that solar water heaters could compete in a larger market. In the Program Case, the baseline assumptions were modified to reflect the program cost and performance goals. The costs were changed for both new and replacement water heaters.

Three changes were made to the representation of distributed PV systems in the Baseline and Program Cases. The size of the typical distributed PV installation was increased to 4 kW per home (from 2 kW) and to 100 kW per commercial building (from 10 kW) to reflect literature on recent installations. In addition, the fraction of eligible buildings was increased from 30 percent to 60 percent for homes and to 55 percent for commercial buildings. The California renewable energy credit program, which provides a PV credit of $4000/kW in 2003 declining by $40/kW per year, was included for the Pacific region. For the program case, the capital and O&M costs were modified to reflect the program's goals. The regional capacity factors in the Baseline Case were similar to those in the program's goals, so they were left unchanged.

In addition to competing on an economic basis with other electricity-generation technologies, PVs may be constructed for their environmental benefits. PERI, using their Green Power Market Model, provided an estimate of PV capacity additions in response to the expanding green power markets in many places throughout the country. The projections for green power PV installations were combined with the Million Solar Roofs Initiative goals (see **Table 4.13**) to determine the planned PV capacity additions that were incorporated into NEMS-GPRA05.

Table 4.13. NEMS-GPRA05 Solar Capacity (GW) and Water Heaters

Photovoltaics	**2010**	**2015**	**2020**	**2025**
GPRA Base				
Central PV	0.1	0.2	0.3	0.4
Distributed PV	0.6	0.6	2.1	9.0
Total	1.2	1.3	2.9	9.9
Solar Program Case				
Central PV	0.3	0.6	0.9	1.2
Distributed PV	1.5	4.1	12.2	24.9
Total	2.2	5.2	13.6	26.5
Incremental Capacity				
Central PV	0.2	0.4	0.6	0.8
Distributed PV	0.8	3.5	10.1	15.9
Total	1.1	4.0	10.8	16.7
Incremental Generation (BkWh)				
Central PV	0.5	1.0	1.5	1.8
Distributed PV	1.7	7.2	20.7	32.0
Total	2.2	8.2	22.2	33.8

Solar Water Heaters	**2010**	**2015**	**2020**	**2025**
GPRA Base				
Million	0.56	0.77	1.01	1.39
Share (percent)	0.5%	0.6%	0.8%	1.1%
Solar Program Case				
Million	1.98	5.23	8.49	12.47
Share (percent)	1.7%	4.3%	6.7%	9.4%

Estimates of primary energy, oil, and carbon emissions savings result from displacement of energy use for water and pool heating, and from electricity demand reductions and PV generation. The savings associated with reduced electricity requirements depend on which types of generating plants were built and operated in the Baseline Case. Over time, the mix of fuels and efficiencies of power generation vary; and, therefore, the energy savings will as well. Energy-expenditure savings are measured as the reduction in consumer expenditures for electricity and other fuels. Lower-cost renewable generation options reduce the price of electricity directly and reduce the pressure on natural gas supply, both of which benefit end-use consumers. Energy savings from water heaters also directly reduce energy expenditures. Overall benefits of the Solar Energy Technologies Program are shown in **Table 4.14**.

Table 4.14. FY05 Benefits Estimates for Solar Energy Technology Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.04	0.12	0.23	0.42
Generation (gigawatt-hours/yr)	2	8	22	34
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	0.2	1.2	6.6	4.9
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	0.9	2.0	4.7	9.0
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.00	0.10	0.10	0.15
Avoided Additions to Central Conventional Power (gigawatts)	1	3	8	10
Program-Specific Electric Capacity Additions (gigawatts)	1	4	11	17

Vehicle Technologies Program

The Vehicle Technologies Program[8] consists of research on light-vehicle hybrid and diesel technologies, heavy-vehicle and parasitic loss-reduction technologies, and lightweight materials for engines and vehicles. In addition, the program includes research in advanced petroleum and renewable fuels.

Light-vehicle hybrid and diesel technologies: This research aims to improve engine technologies in light-duty vehicles, which include passenger cars and light-duty trucks. Analysts compute benefits estimates for these activities through a process that estimates the penetration (sales) of the various technologies in the market for light-duty vehicles over time. The amount that each technology penetrates into the market determines the stock of these vehicles and the vehicle miles traveled (VMT) associated with each technology.

Heavy-vehicle and parasitic loss-reduction technologies: Heavy vehicles are those that have a gross weight (the weight when fully loaded) of 10,000 pounds or more. The benefits of this R&D

[8] The Vehicle Technologies Program is run by the Office of FreedomCAR and Vehicle Technologies.

activity are derived from penetration rates estimated by the Heavy Vehicle Model developed for the Vehicle Technologies Program, using efficiency and technology cost assumptions.

Lightweight materials for engines and vehicles: The lightweight materials developed under this R&D activity are used in both light and heavy vehicles. The benefits estimates for material are proportional to the percent of the fuel economy gain in light vehicles that is due to weight reduction. The benefits from weight reduction for heavy vehicles will be estimated in the future, but they are not in the current estimates.

In the NEMS-GPRA05 integrating model, the light-duty vehicle (LDV) market consists of six car classes—mini-compact, subcompact, compact, midsize, large, two-seater—and six light-duty truck classes—small and large pickup, small and large van, small and large sport utility vehicle (SUV)—in nine Census divisions. For each vehicle type and class and for each region, a number of LDV technologies compete against each other in the market for vehicle sales. These include conventional gasoline, advanced combustion diesel, gasoline hybrids, diesel hybrids, hydrogen internal combustion engine, gasoline fuel cell, hydrogen fuel cell, electric, natural gas, and alcohol. Each vehicle technology is represented by a number of characteristics that can change over the forecast time horizon and that influence the technology's acceptance in the marketplace (*i.e.*, its sales). These characteristics include the vehicle cost, the fuel cost per mile (a combination of the fuel price and the vehicle efficiency), the vehicle range, the operating and maintenance cost, the acceleration, the luggage space, the fuel availability, and the make and model availability. The NEMS-GPRA05 model also includes "calibration" coefficients to calibrate the model to historical data. The associated characteristics for all the "nonconventional" technologies are specified as relative to those for the conventional gasoline vehicle.

The model estimates the sales-penetration share of each technology in all of the vehicles, classes, and regions in each year of the forecast. The various characteristics of the technologies determine the technology's acceptance in the marketplace, but each characteristic has a differing degree of influence.[9] The vehicle cost is generally the most influential of the characteristics, certainly having a much stronger influence than luggage space for example. All the technologies are competed against each other using a nested logit formulation. In a logit formulation, the sum of all the influences from the characteristics for each technology is the "utility" for that technology, and the relative sizes of the "utility" for each technology determines the relative penetration shares for that technology. Technologies that have higher "utilities" are given greater sales shares. The overall sales-penetration results are the sum of all the more disaggregated results.

In the FY 2005 benefits analysis, the Baseline Case for transportation programs is essentially the *AEO2003* Reference Case, which already includes some small amount of penetration for the program vehicle technologies. The Program Case uses the program technology characteristics, along with a variety of other assumptions relating to behavioral responses in the underlying logit formulation of the NEMS-GPRA05 model. These include moving away from the "calibration"

[9] The vehicle shares are sensitive to assumptions about consumer preference for each vehicle attribute. In the NEMS-GPRA05 transportation model, a different set of consumer-choice assumptions is made than those in the NEMS *AEO2003* transportation model, leading to different rates of technology adoption.

coefficients over the forecast period (used by the model for a tie to history), and reworking the manner in which the make and model availability coefficients are used.

Using the fully integrated NEMS-GPRA05 model, the overall sales share for gasoline vehicles in 2025 falls from 80 percent in the Baseline Case to 38 percent in the Program Case (**Figure 4.3**). This decrease in share is due to the penetration of the alternative technologies. The overall share in 2025 for advanced combustion diesel increases from 4 percent to 24 percent, for gasoline hybrids from 9 percent to 19 percent, and for diesel hybrids from 1 percent to 14 percent.

These large-vehicle sales shares for advanced technology vehicles in 2025, however, translate into much smaller shares of overall vehicle stocks and overall shares of vehicle miles traveled (VMT) for each technology. The stock shares depend on the share of sales over time, which only gradually increases for the alternative-technology vehicles, and the rate of vehicle replacement and growth. The total VMT for gasoline vehicles falls from 3,367 billion miles in 2025 to 2,516 billion miles (about 60 percent of the VMT) between the two cases (**Figure 4.4**). The total VMT for advanced combustion diesel increases from 151 to 467 billion miles (11 percent), for diesel hybrids from 18 to 300 billion miles (6 percent), and for gasoline hybrids from 295 to 685 billion miles (16 percent).

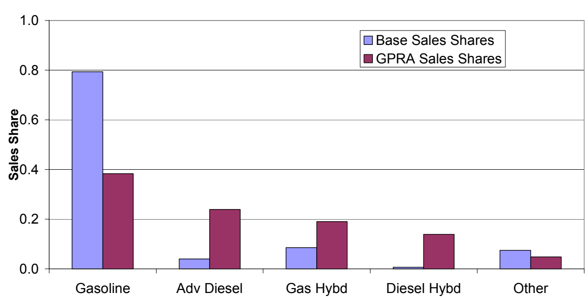


Figure 4.3. Sales Shares in 2025

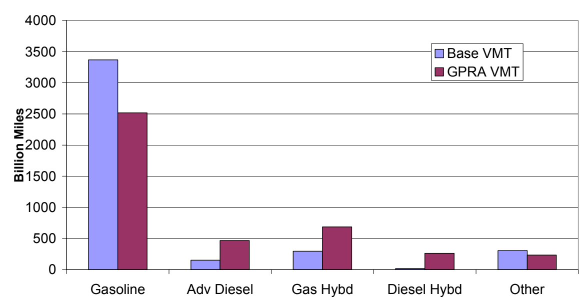


Figure 4.4. Vehicle Miles Traveled in 2025

The miles per gallon (MPG) for advanced combustion diesel and for hybrid vehicles is much greater than the MPG for conventional gasoline vehicles. As a consequence, since these advanced-technology vehicles are substituting for the conventional gasoline vehicles, there is a considerable amount of fuel savings.

In these fully integrated NEMS-GPRA05 model runs, the savings are typically somewhat less than if they were estimated in a transportation-only model, because of feedback effects that come through the integration with other sectors. The primary feedback effect occurs through lower fuel prices. In this case, reduced gasoline demand causes lower gasoline prices, which leads to an increase in travel and less-efficient vehicle purchases than would otherwise have occurred absent the price change. The rebound of gasoline consumption reduces the program savings. At the same time, energy-expenditure savings are greater. The small decreases in price apply to the total amount of fuel consumed and contribute significant additional expenditure savings. In addition, the "rebound" effect is also influenced by the fact that vehicles are more efficient, thereby reducing the cost to drive, causing more miles to be driven. **Table 4.15** presents the total program benefits, including those of heavy trucks.

Table 4.15. FY05 Benefits Estimates for Vehicle Technologies Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.19	0.65	1.55	2.94
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	6.4	9.0	27.5	55.5
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	4	13	29	54
Security				
Oil Savings (mbpd)	0.08	0.27	0.67	1.39
Natural Gas Savings (quadrillion Btu/yr)	ns	ns	ns	-0.10
Avoided Additions to Central Conventional Power (gigawatts)	ns	ns	ns	ns

Weatherization and Intergovernmental Program

The Weatherization and Intergovernmental Program (WIP) encompasses a broad range of activities in virtually all demand sectors of the energy economy. These activities generally are comprised of market enhancement, rather than R&D. The major components include: International, Native American Renewable Initiative (also referred to as Tribal Energy), Weatherization (Assistance), State and Community Grants, and Gateway Deployment (Energy Star, Clean Cities, Inventions and Innovations, and building codes). The FY 2005 benefits estimate methodologies vary by activity.

The international activities are currently outside the scope of the integrated modeling framework. The Native American renewable initiative also is not being modeled for this year. Weatherization and State and Community grants are implementation programs that lead to greater adoption of energy efficiency. They are represented by reducing energy consumption in the residential sector, based on the program goals.

The Clean Cities subprogram is represented through an increase in alternative-fuel vehicles. Analysts determined the cumulative number of expected vehicles participating in Clean Cities through off-line analysis. These were converted to annual vehicle sales and used as inputs into NEMS-GPRA05. The incremental sales were allocated to vehicle types, based on program information, although the fuel types in the model do not directly correspond in all cases. The largest share of vehicles are compressed natural gas, ethanol, and liquefied petroleum gas. Electric and methanol vehicle shares are small.

The Inventions and Innovation (I&I) subprogram savings estimates are based on numerous individual technologies receiving grants in the previous year, because this is the most recent year of award data available for analysis. For this analysis, the projects with the greatest expected energy savings are represented using specific technology characteristics or by targeting the energy-savings goals of the individual projects funded. This year, the technologies include two inventions involving ethanol production, two buildings equipment, and one industrial process. The ethanol and industrial process inventions could not be modeled on an economic basis within NEMS-GPRA05, so the estimated off-line energy savings were used in the model after being discounted by 30 percent to 50 percent to reflect potential interactions with other EERE markets and technologies. This discounting is comparable to that used for the Industrial Technologies Program. In the building sector, the electrochromic windows reduce heating and cooling loads. Based on an analysis performed by PNNL,[10] the windows were modeled in NEMS-GPRA05 based on technology cost and efficiency characteristics. The humidity-control invention was modeled using an assumption of air-conditioning savings in homes with commercial applications and in the markets where humidity control is important.

Analysts represented the Energy Star activities of Gateway Deployment by modifying the consumer-behavior coefficients, indicating how consumers trade first-cost expenditures for annual energy savings. The program goals for market penetration were used to determine the degree of change of these parameters. For the compact fluorescent bulb (CFL) activities, the target market share was defined as the fraction of lighting demand rather than the fraction of bulbs, in order to reflect that CFLs are most likely to be installed in high-use fixtures. The other component of Gateway Deployment is a portion of the savings associated with the upgrading of building codes. Because the other portion of the building code savings are attributed to the Building Technologies Program, the entire code effort was modeled as part of the Building Technologies Program, and then a fraction based on the program estimates was allocated to WIP. Overall benefits for WIP are shown in **Table 4.16**.

Table 4.16. FY05 Benefits Estimates for Weatherization and Intergovernmental Program (NEMS-GPRA05)

Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.42	0.67	0.90	1.08
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	5.2	7.7	10.9	16.8
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	8.2	13.3	19.1	24.3
Security				
Oil Savings (mbpd)	0.00	0.00	0.10	0.10
Natural Gas Savings (quadrillion Btu/yr)	0.19	0.29	0.29	0.23
Avoided Additions to Central Conventional Power (gigawatts)	4	8	10	9
Total Electric Capacity Avoided (gigawatts)	6	11	11	13

Wind and Hydropower Technologies Program

The wind component of the Wind and Hydropower Technologies Program seeks to reduce the cost—and improve the performance—of wind generation. The FY05 benefits are based primarily on projecting the market share for wind technologies, based on their economic characteristics.

The hydropower subprogram goal is to reduce the environmental impact of hydroelectric facilities. Because this program is driven more by environmental than economic concerns, off-

[10] See Appendix K on the Weatherization and Intergovernmental Program analysis.

line analysis provided the market-penetration estimates for incremental capacity and generation that are the primary source for the FY 2005 benefits estimates.

Representation of Wind: The NEMS-GPRA05 electricity-sector module performs an economic analysis of alternative technologies in each of 13 regions. Within each region, new capacity is selected based on its relative capital and operating costs, its operating performance (*i.e.*, availability), the regional load requirements, and existing capacity resources. Unlike the *AEO2003* version of NEMS, NEMS-GPRA05 characterizes wind by three wind classes, which each have their own capital costs and resource cost multipliers. For example, wind turbines being developed by the program for use in Class 4 winds are expected to be more expensive, but deliver more electricity per unit of capacity. The regional resource cost multipliers act to increase costs as more of a wind class is developed in a region, and development may move to the next most cost-effective wind class. The same resource multipliers are used as in the *AEO2003*, although they are applied at the class level rather than for the entire regional resource. Other key assumptions that can affect projections include a limit on the share of generation in each region that can be met with intermittent technologies.[11] NEMS-GPRA05, as in the *AEO2003*, assumes that the capacity value of wind diminishes with greater wind capacity in a region. Finally, another constraint on the growth of wind-resource development is how quickly the wind industry can expand before costs increase due to manufacturing bottlenecks. The *AEO2003* assumption that a cost premium is imposed when new orders exceed 50 percent of installed capacity was maintained for the Program Case analysis (see **Table 4.17**).

Table 4.17. Wind Capacity (GW)

		2010	2015	2020	2025
AEO Base		8.5	10.1	11.0	12.0
GPRA Baseline					
By Wind Class	Class 6	3.1	3.3	3.3	3.3
	Class 5	1.4	1.7	1.7	1.7
	Class 4	3.4	3.7	4.0	4.0
	Total	7.9	8.7	9.0	9.1
Wind Program Case					
By Wind Class	Class 6	4.2	7.5	9.3	9.3
	Class 5	5.1	5.5	5.5	5.9
	Class 4	5.3	19.3	49.1	52.5
	Total	14.6	32.3	63.9	67.7
Incremental Capacity					
By Wind Class	Class 6	1.0	4.2	6.0	6.0
	Class 5	3.7	3.8	3.8	4.1
	Class 4	1.9	15.6	45.1	48.5
	Total	6.7	23.6	54.9	58.6

Analysts represented the Wind Program R&D activities by reducing the capital and O&M costs and increasing the performance of wind capacity to match the program cost goals. In addition to competing on an economic basis with other electricity-generation technologies, wind capacity

[11] The *AEO2003* assumption that wind may provide only a maximum of 20 percent of a region's generation was maintained although the program disagrees with that characterization.

may be constructed for its environmental benefit. PERI, using their Green Power Market Model, provided an estimate of wind capacity additions in response to the expanding green power markets in many places nationwide. Analysts incorporated the projections for green power wind installations into NEMS-GPRA05 as planned capacity additions.

Representation of Hydropower: Hydropower Program analysts expect that future hydroelectric capacity and generation may decrease due to environmental concerns as facilities undergo relicensing. The program goal is to develop hydro turbines that reduce fish mortality rates, and therefore reduce the risk of these capacity reductions. The *AEO2003* projected relatively constant hydropower, implying that the technology was assumed to be deployed already or that the issue had not been examined. As a result, the Baseline Case was modified to reflect a loss of 6 percent of hydro capacity and generation by 2025 in the absence of the fish-friendly turbines. The Program Case then returned hydropower to the prior constant levels, and the forecast benefits result from the increased hydroelectric output.

The program is also working on methods to optimize generation from hydroelectric facilities and provide additional electricity with little capital investment. The program's goal of increasing generation from existing facilities up to 6 percent by 2020 was incorporated in NEMS-GPRA05 by increasing the hydro capacity factors.

Table 4.18 provides the estimates of primary energy, oil, and carbon emissions savings stemming from wind and hydropower displacing fossil-fueled generation sources. Analysts measure the energy-expenditure savings as the reduction in consumer expenditures for electricity and other fuels. Lower-cost renewable generation options reduce the price of electricity directly and reduce the pressure on natural gas supply, both of which benefit end-use consumers.

Table 4.18. FY05 Benefits Estimates for Wind and Hydropower Technologies Program (NEMS-GPRA05)

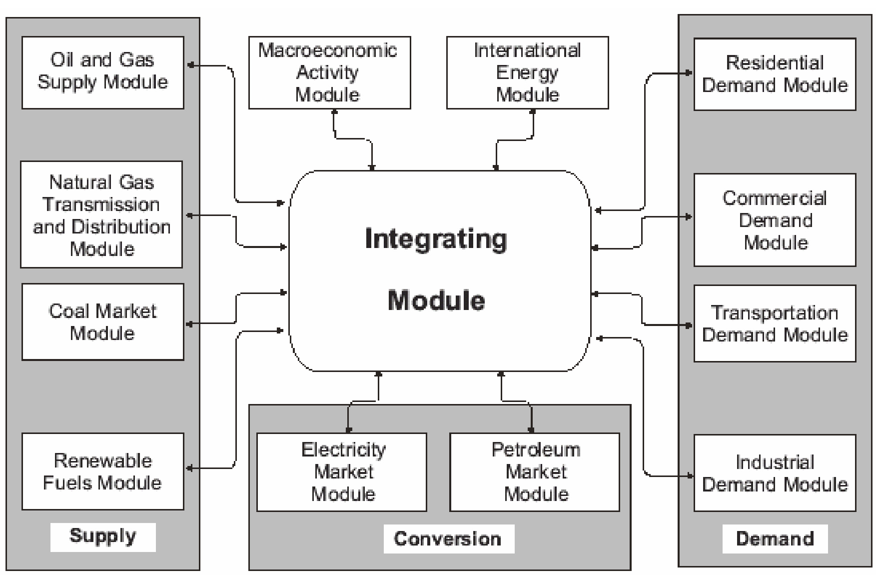
Benefits	2010	2015	2020	2025
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.27	0.79	1.65	1.77
Generation (gigawatt-hours/yr)	41	105	232	248
Economic				
Energy-Expenditure Savings (billion 2001 dollars/yr)	1.1	4.2	12.0	3.9
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	5.6	16.1	32.7	38.9
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.12	0.37	0.84	0.57
Avoided Additions to Central Conventional Power (gigawatts)	6	9	13	20
Program-Specific Electric Capacity Additions (gigawatts)	10	28	59	63

Box 4.1—EIA's National Energy Modeling System (NEMS)*

The National Energy Modeling System (NEMS) is an energy-economy modeling system of U.S. energy markets for the midterm period through 2025. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). As described in the GPRA Baseline section, the NEMS-GPRA05 version of the model used for the EERE GPRA analysis includes minor modifications to the standard EIA NEMS.

NEMS is designed as a modular system. Four end-use demand modules represent fuel consumption in the residential, commercial, transportation, and industrial sectors; subject to delivered fuel prices, macroeconomic influences, and technology characteristics. The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy; subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel. Because of the modular design, each sector can be represented with the methodology and the level of detail (including regional detail) that is appropriate for that sector.

A key feature of NEMS is the representation of technology and technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, and refining—include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the sector. Technological progress results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies and for a decline in cost as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment. In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is more limited, due to a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicitly considered and characterized. Cost reductions resulting from technological progress in combined heat and power technologies are represented as a function of time as experience with the technologies grows. Technological progress is not explicitly modeled for the industrial motor technologies. Other technologies in the energy-intensive industries are represented by technology bundles, with technology possibility curves representing efficiency improvement over time. In the oil and gas supply sector, technological progress is represented by econometrically estimated improvements in finding rates, success rates, and costs. Productivity improvements over time represent technological progress in coal production.



* Most of this description is taken from *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003), March 2003.

CHAPTER 5

LONG-TERM BENEFITS ANALYSIS OF EERE'S PROGRAMS

Introduction

This chapter provides an overview of the modeling approach used in MARKAL-GPRA05 to evaluate the benefits of EERE R&D programs and technologies. The program benefits reported in this section result from comparisons of each Program Case to the Baseline Case, as modeled in MARKAL-GPRA05.

The Baseline Case used to evaluate the impact of the EERE portfolio was benchmarked to EIA's *Annual Energy Outlook 2003* (*AEO2003*) for the period between 2000 and 2025. To the extent possible, the same input data and assumptions were used in MARKAL-GPRA05 as were used to generate the *AEO2003* Reference Case. For example, the macroeconomic projections for GDP, housing stock, commercial square footage, industrial output, and vehicle miles traveled were taken from the *AEO2003*. At the sector level, both supply-side and demand-side technologies were characterized to reflect the *AEO2003* assumptions, in cases where the representation of technologies is similar between MARKAL (MARKet ALlocation) and the National Energy Modeling System (NEMS). The resulting projections track closely with the *AEO2003* at the aggregate level, although they do not match exactly at the end-use level. For the period after 2025, various sources were used to compile a set of economic and technical assumptions. For instance, the primary economic drivers of GDP and population were based on the real GDP growth rate from the Congressional Budget Office's *Long-Term Budget Outlook* and population growth rates from the Social Security Administration's 2002 *Annual Report* to the Board of Trustees. **Appendix A** provides a more complete discussion of the MARKAL-GPRA05 Baseline Case.

For each EERE R&D program, analysts make modifications to the characteristics of the technologies involved to generate a Program Case. Program Cases also may include technologies not available in the Baseline Case. The modifications made to the model parameters and attributes of a technology depend on the nature of the program. They directly affect the technology's competitiveness and market deployment presented in the model.

Table 5.1 provides a breakdown by program of the two types of analytical methods employed in EERE's long-term benefits analyses—specialized "off-line" tools and MARKAL-GPRA05. The activities listed are groupings of activities within each program that share either technology or market features. They do not represent actual program-management categories. A description of the MARKAL model is provided in **Box 5.1** at the end of this chapter. Descriptions of the off-line models are provided in the related program appendix. It is important to note that the offline analysis served to feed appropriate parameters and other factors into MARKAL-GPRA05, which was then run for all the programs. The indication that the Industrial Technologies Program (or other program areas) was modeled using off-line tools should not be interpreted to mean that the Industrial Technologies Program was not included in the MARKAL-GPRA05 modeling, or that the results of the Industrial Technologies Program analysis are not impacted by the MARKAL-GPRA05 modeling.

Table 5.1. Long-Term Benefits Modeling by Primary Type of Model Used and Activity Area

Program	Activities	Off-Line Tools	MARKAL-GPRA05
Biomass	Bio-based Products	✓	
	Cellulosic Ethanol	✓	✓
Buildings Technologies	Residential Sector	✓	
	Commercial Sector	✓	
DER	DER / CHP		✓
FEMP	FEMP	✓	
Geothermal	Geothermal		✓
Hydrogen, Fuel Cells, and Infrastructure Technologies	Fuel Cells		✓
	Production		✓
Industrial Technologies	R&D	✓	
	Deployment	✓	
Solar Energy Technologies	Solar Water Heaters		✓
	Photovoltaics	✓	✓
Vehicle Technologies	Light-Vehicle Hybrid and Diesel		✓
	Heavy Trucks		✓
Weatherization and Intergovernmental	Weatherization	✓	
	Domestic Intergovernmental	✓	
Wind and Hydropower Technologies	Wind		✓
	Hydropower	✓	

The following sections summarize how each EERE R&D program is formulated in MARKAL-GPRA05. In many cases, analysts convert the technological data and their projected market potentials in each program directly to MARKAL-GPRA05 input. When this is not feasible, the quantitative analyses undertaken in **Step 2** are used, in part, to generate the Program Cases.

Biomass Program

The goal of the Biomass Program is the development of biomass refineries, which produce a range of products including ethanol and biochemical feedstocks. This refinery approach reduces the cost of these biomass products compared to the earlier approach of individually producing each product. Unfortunately, it is currently not possible to directly model a biorefinery. Instead, analysts model individual biorefinery products (bio-based products and cellulosic ethanol) for the benefits analysis. This most likely results in an underestimation of the size of future markets and resulting benefits.

Bio-based products: In the Baseline Case, the supply/demand of petrochemical feedstocks is explicitly represented as nonenergy use of petroleum products and natural gas. At this early stage of biorefinery R&D, the output and cost of biorefineries are not yet well defined. Off-line projections of the use of petroleum and natural gas as chemical feedstock are represented in a highly aggregated manner. Program goals are estimated off-line and represented in MARKAL-GPRA05 as reductions in petroleum and natural gas demand for feedstocks. Off-line estimates include changes in fuel requirements for process heat. The off-line energy savings for displaced feedstocks and changes in process heat are represented in the MARKAL-GPRA05 model as upper bounds in the amounts shown in **Table 5.2**.

Table 5.2. Bio-based Products Energy Savings by Year

	2010	2020	2030	2040	2050
Natural Gas (TBtu/yr)	7.49	12.20	21.85	39.13	70.08
Coal (TBtu/yr)	-0.82	-1.34	-2.40	-4.31	-7.71
Electricity (Billion kWh/yr)	-0.66	-1.07	-1.92	-3.45	-6.17
Distillate (TBtu/yr)	7.88	12.84	22.99	41.16	73.72
Oil Feedstock (TBtu/yr)	18.27	29.74	53.26	95.38	170.82
Total (TBtu/yr)	**26.87**	**44.96**	**80.51**	**144.18**	**258.20**

Cellulosic ethanol: In the Biomass Program Case, a cellulosic ethanol production process is introduced, which is capable of producing ethanol beginning in 2007 at an initial cost comparable to current corn ethanol.[1] The enzyme-based technology for converting the cellulose and hemi-cellulose from the fiber contained in corn kernels will be available sooner than the related (but more complex) enzyme-based technology for converting agricultural residues to ethanol. Beginning in 2019, biorefineries producing ethanol as a major product, along with high-value coproducts, from biomass wastes and residues, will begin operation. However, as ethanol volumes increase, the total cost may increase as the process competes with other biomass-based technologies for the supply of biomass it uses as feedstocks. Currently, the MARKAL-GPRA05 model lacks sufficient technical detail to properly capture beneficial qualities of ethanol, such as octane enhancement; or the regional detail to model niche markets in agricultural states where ethanol/gasoline blends may compete on an even basis with traditional gasoline. Therefore, estimates of future ethanol demand from biomass-specific models are used for both the Baseline and Program Cases. In MARKAL-GPRA05, a portion of the total gasoline supply is blended with ethanol to produce blended ethanol for use in road vehicles. A single blending level (5.6 percent ethanol) is used in the model to match estimated demand. Actual blend levels vary across the country due to regulations and cost competitiveness. For instance, in some agricultural regions of the country, higher ethanol blends may be cost-competitive. **Table 5.3** depicts the upper bound of cellulosic and corn ethanol production set in MARKAL-GPRA05, which reflects cellulosic ethanol's penetration if program cost goals are met.

Table 5.3. Projected Ethanol Demand (million gallons/year)

	2000	2010	2020	2030	2040	2050
Corn	1,600	3,000	3,140	2,920	2,680	2,380
Cellulosic	0	90	710	3,010	6,400	10,200
Total	**1,600**	**3,090**	**3,850**	**5,930**	**9,080**	**12,580**

The benefits of the Biomass Program derived in MARKAL-GPRA05 (**Table 5.4**) are the results of direct substitution of biomass-based energy for fossil fuels. Bio-based products reduce the demand for petroleum feedstocks. Cellulosic ethanol displaces an increasing fraction of the gasoline used in light-duty vehicles (LDVs) in later periods. The reduction in fossil fuel consumption at high marginal cost generates savings both in carbon emissions and energy-system costs.

[1] Cellulose and hemi-cellulose that can be converted to ethanol (and other chemicals, materials, and biofuels) are found in biomass such as agricultural residues (corn stover, wheat, and rice straw), mill residues, organic constituents of municipal solid wastes, wood wastes from forests, future grass, and tree crops dedicated to bio-energy production.

Table 5.4. FY05 Benefits Estimates for Biomass Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.11	0.38	0.73	1.20
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	2	3	2	0
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	1	4	11	23
Security				
Oil Savings (mbpd)	0.0	0.0	0.2	0.4
Natural Gas Savings (quadrillion Btu/yr)	0.07	0.32	0.34	0.36

Buildings Technologies Program

MARKAL-GPRA05 models technologies and activities in the Buildings Program based on two general types of activities: technology R&D and regulatory actions.

Technology R&D: New and improved technologies are introduced into MARKAL-GPRA05 by modifying the technology slates that are available in the Baseline Case. These modifications are accomplished by changing any (or all) of the following three parameters to reflect program goals: the date of commercialization, capital cost, and efficiency. Building technologies for which these parameters can be characterized to meet specific building service demands include end-use devices such as heating burners, air conditioners, and water heaters (**Figure 5.1**). In instances where the market potentials of a technology were estimated off-line, a maximum initial market penetration rate was imposed, combined with an annual growth rate limit to replicate these potentials in MARKAL-GPRA05. For example, in the Buildings Program Case, an improved electric heat-pump water heater was modeled in the residential sector with an initial maximum market penetration of 400 TBtu and a potential growth rate of 5 percent per year. In the commercial sector, solid-state lighting technologies for 2010, 2015, and 2020 are modeled with their technological characteristic shown in **Table 5.5**.

Table 5.5. New Commercial Lighting Technologies

	Maximum Initial Penetration*	Annual Growth Rate	Investment Cost**
Solid-State Lighting 2010	1000	5.0%	4.3079
Solid-State Lighting 2015	2000	5.0%	3.8437
Solid-State Lighting 2020	5000	10.0%	3.8437
Lighting Controls	500	5%-10%	2.6795

* Maximum initial investment is in 10^12 lumens-second
** Lighting investment cost in million $ per 10^12 lumen-second capacity

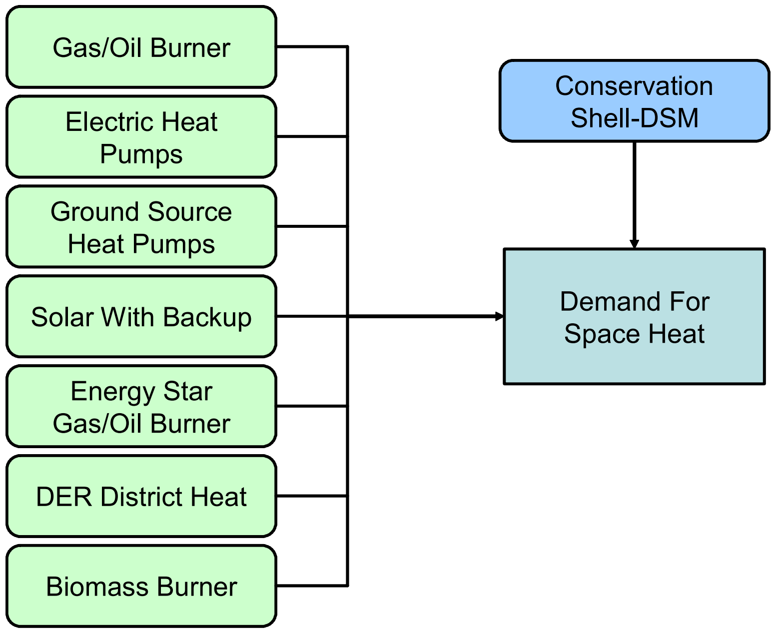


Figure 5.1. Demand-Side Linkages for End-Use Technologies and Energy Services

Technologies that lower service demand (*e.g.*, building shell technologies, lighting controls) are modeled in MARKAL-GPRA05 as conservation supply steps. Each supply step is characterized by capital cost, load-reduction potentials expressed as upper bounds of market penetration, consumer's hurdle rate, and technology lifetime. These conservation steps reduce the market size or load demand for end-use devices (**Figure 5.1**). In the Buildings Program Case, these newly introduced technologies compete with the baseline technologies for market share. For example, in future time periods, the size of the market for commercial air conditioning is the projected total heat in trillion Btus to be removed from the service areas. The new investment opportunity in that time period is the difference between the projected service demands in that period and the vintage capacities carried over from the previous period.

Technologies such as solid-state lighting in commercial buildings, although available in the Baseline Case, do not have a market share initially because of their high consumer hurdle rate (44 percent). These hurdle rates are lowered to 18 percent when running the Buildings Technology Case to reflect consumer acceptance of these products with improved performance.[2] The 18 percent is an empirical value based on observed consumer responses, but is much higher than would be observed if consumers were minimizing life cycle costs. Although the future market potential of new lighting technologies is great due to the relatively short life of the equipment, the penetration of these technologies modeled in MARKAL-GPRA05 is limited to a sustainable growth path that generates a potential market penetration path consistent with the program goals.

[2] The hurdle rates in MARKAL-GPRA05 include factors to reflect both the interest rate available to consumers, as well as behavioral and risk premiums that are implicit in consumer decisions. Behavioral premiums would reflect a documented consumer bias towards choosing reduced up-front investment costs over longer-term operating cost savings. The behavioral premium also incorporates agency issues where the decision maker would not benefit from long-term operating costs and, thus, would make decisions based primarily on initial capital costs. Risk premiums would apply to new, unfamiliar products that are presumed to be less desirable to consumers due to the lack of familiarity or a track record of successful application. Also, risk premiums would be appropriate for modeling situations where technologies may appear to be cost effective on paper, but are not chosen by consumers for reasons such as convenience, styling or lack of availability.

Regulatory Activities: Analysts represent new appliance standards and building codes in MARKAL-GPRA05 as either new technologies or energy-conservation supply steps. In the time period that a new standard becomes effective, the model removes technologies with efficiency below the set standard from the market. Regulatory activities primarily affect the performance of new energy products for a specific end-use product purchased by consumers in future markets. The overall impact of the Buildings Program, therefore, depends on the size of these markets. MARKAL-GPRA05 determines the size of these markets by dynamically keeping track of the turnover of capital equipment and deriving the new investment needed to meet projected energy service demands. Because some end-use devices (*e.g.*, heating equipments) have a long service lifetime, the stock turnover constraints modeled in MARKAL-GPRA05 limit near-term energy savings. **Table 5.6** depicts the size of the future markets for the major end-use categories defined in MARKAL-GPRA05 for buildings.

Table 5.6. Projected Annual Investment in Energy Capital Stock Used in Buildings

	2010	2020	2030	2040	2050
Residential Sector					
Space Heating (Million Units/yr)[1]	3.86	4.25	4.39	4.63	5.02
Air Conditioning (Million Ton/yr)	9.30	10.22	10.47	11.34	12.79
Water Heating (Million Units/yr)[2]	2.87	2.94	3.10	3.20	3.43
Refrigeration (Million Units/yr)[3]	2.99	2.80	3.32	3.34	3.44
Lighting (Million Units/yr)[4]	207.78	246.90	258.48	268.84	275.62
Commercial Sector					
Space Heating (Billion Btu per Hour/yr)	65.89	70.46	85.08	96.40	98.53
Air Conditioning (Million Ton/yr)	7.20	8.21	8.70	9.87	10.65
Water Heating (Billion Btu per Hour/yr)	9.90	11.22	12.91	14.30	14.94
Lighting (Million Units/yr)[5]	144.54	166.54	179.45	208.80	232.02

[1] Units with equivalent capacity of 150,000 Btu/hour.
[2] Units with equivalent capacity of 30,000 Btu/hour.
[3] Units with equivalent capacity of 1500 W.
[4] In terms of a 75W incandescent light or equivalent.
[5] In terms of a 40W standard fluorescent light or equivalent.

In MARKAL-GPRA05, energy savings are achieved when a more efficient and economic (on a life-cycle basis) end-use device is selected to substitute for a conventional device competing in the same market. For example, a 20 Watt (W) CFL can replace a 75W incandescent lightbulb and provide the same level of lighting service, but uses much less electricity. The total market potential for this substitution in a future time period, however, is constrained by the investment opportunity established in MARKAL-GPRA05 (*e.g.*, 275.62 million units for residential lighting in 2050, as shown in **Table 5.6**).

For building codes, analysts estimated unit load reductions in heating, cooling, and lighting demands—resulting from the implementation of more stringent building codes—within NEMS and implemented in MARKAL-GPRA05 as a set of conservation curves. **Table 5.7** depicts these potentials used in formulating the Buildings Program Case. The reduced loads or energy service demands lead to less electricity and fuels used in buildings.

Table 5.7: Building Conservation/Load-Reduction Potentials: Building Code and Envelop Improvement (% of total load)

	2010	2020	2030	2040	2050
Residential Sector					
Heating	0.5%	2.4%	3.1%	3.1%	3.1%
Cooling	1.8%	1.6%	3.0%	3.0%	3.0%
Commercial Sector					
Heating	1.5%	5.0%	5.8%	5.8%	5.8%
Cooling	2.2%	5.2%	5.2%	5.2%	5.2%

Tables 5.8 and 5.9 depict the projected delivered energy savings by demand and fuel generated from the use of more efficient end-use devices and cost-effective conservation measures covered under the Buildings Program.

Table 5.8. Residential Delivered Energy Savings by Demand and Fuel (trillion Btu/year)

	2010	2020	2030	2040	2050
Reduction by Service Demand					
Space Heating	24	142	207	348	497
Space Cooling	12	12	24	21	15
Water Heating	55	136	298	369	351
Lighting	60	0	0	0	0
Other	0	0	0	0	0
Total	**151**	**290**	**528**	**737**	**863**
Reduction by Fuel					
Petroleum	0	-2	105	246	323
Natural Gas	44	170	318	638	741
Coal	0	0	0	4	4
Electricity	107	122	106	-151	-204
Total	**151**	**290**	**528**	**737**	**863**

Table 5.9. Commercial Delivered Energy Savings by Demand and Fuel (trillion Btu/year)

	2010	2020	2030	2040	2050
Reduction by Service Demand					
Space Heating	27	104	142	132	149
Space Cooling	10	30	27	21	22
Water Heating	0	0	0	0	0
Lighting	20	149	423	716	755
Other	0	0	0	0	0
Total	**57**	**283**	**592**	**869**	**926**
Reduction by Fuel					
Petroleum	10	0	22	0	1
Natural Gas	5	82	102	4	17
Coal	0	0	0	0	0
Electricity	41	201	467	865	905
Total	**57**	**283**	**592**	**869**	**923**

In addition to the reduction in delivered primary energy, the reduction in electricity demand in buildings also leads to the reduction in gas-fired generation capacity, as well as fuel used for generation. Furthermore, building code and envelop improvements reduce both the demand for delivered energy and the required output capacity of end-use devices, such as furnaces or air conditioners. Thus, consumers see both a reduction in their energy bills, as well as reduced capital costs for end-use appliances. This is another factor attributable to the overall reduction in energy-system cost in addition to direct energy savings.

Table 5.10. FY05 Benefits Estimates for Building Technologies Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	1.2	2.3	2.3	2.8
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	15	23	34	45
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	25	43	43	50
Security				
Oil Savings (mbpd)	0.0	0.1	0.2	0.2
Natural Gas Savings (quadrillion Btu/yr)	0.56	1.12	1.54	1.82
Electricity Capacity Avoided (gigawatts)	46	46	48	53

Distributed Energy Resources Program

The Distributed Energy Resources (DER) Program covers distributed generation technologies (DG) and combined heat and power (CHP). The program focuses on the improvement of these technologies (higher efficiency, lower cost, and lower emissions) and removal of market barriers for consumer acceptance.

The DER Program Case in MARKAL-GPRA05 is formulated by the introduction and performance improvements in several combined heat and power technologies. Two of these are for industrial applications: A relatively large gas-fired turbine (10 MW) and a smaller internal combustion engine (3 MW). Both produce electricity and heat for industrial-process steam. The third technology is a micro-turbine (100 KW)-based CHP serving commercial building electricity demand, and space and water heat. The heat generated from CHP is utilized through heat exchangers, displacing the conventional heating devices and the fuel they use. The fourth technology is a 1 MW-distributed generator to meet local peaking demands. The overall efficiencies and capital costs used to characterize these technologies are assumed to become more favorable due to R&D achievements expected from the DER Program (**Table 5.11**).

All of these technologies are modeled explicitly as decentralized systems in MARKAL-GPRA05 and do not require transmission and distribution for their electricity or heat output; and, therefore, avoid the associated costs and electricity losses. Implicitly, this improves the electric reliability at the end-use locations—although this value to consumers is not reflected in the model representation of consumer choices. In addition to the improvements in technological attributes, the discount (hurdle) rate of DG technologies are lowered by one percentage point to reflect DER's activities in enhancing the technologies' consumer acceptance. As currently modeled, distributed generation technologies do not directly contribute to the overall system peak in electric power demand.[3]

Under the DER Program, MARKAL-GPRA05 results in accelerated market penetration of DER technologies, as shown in **Table 5.12**.

Table 5.11. Distributed Generation Technology Assumptions

	2000	2005	2010	2015	2020
10MW Industrial Turbine					
Cost (2001$/kW)	950	914	879	843	807
Electric Efficiency	29%	30%	32%	33%	34%
Combined Efficiency	69%	70%	70%	71%	71%
3MW Industrial Gas Engine					
Cost (2001$/kW)	843	677	511	511	511
Electric Efficiency	34%	42%	50%	50%	50%
Combined Efficiency	65%	66%	67%	67%	67%
100kW Commercial Microturbine					
Cost (2001$/kW)	2000	1400	601	601	601
Electric Efficiency	26%	33%	40%	40%	40%
Combined Efficiency	65%	68%	70%	71%	72%
1MW Distributed Peaking Units					
Cost (2001$/kW)	766	613	460	460	460
Electric Efficiency	31%	36%	40%	40%	40%

Table 5.12. Installed Distributed Generation Capacity by Sector and Case (gigawatts)

	Commercial Sector	Industrial Sector	Distributed Peakers	Total
Baseline Case				
2015	0	62	6	68
2025	1	73	16	90
2050	8	131	171	310
DER Program Case				
2015	0	64	7	71
2025	12	78	20	110
2050	51	146	212	409
Increase				
2015	0	2	1	3
2025	11	5	4	20
2050	44	15	41	99

With the increase in distributed generation capacity, MARKAL-GPRA05 directly reduces the investment in centralized gas and coal-fired generators. On the demand side, the heat generated

[3] This will be addressed in the GPRA06 benefits analysis.

from CHP further reduces fuel use for space and water heat in buildings, and for process steam in industrial applications. The higher overall efficiency (combined heat and power with no transmission loss) of these technologies results in long-term benefits in energy savings, energy-system costs, and carbon emission reductions (**Table 5.13**).

Table 5.13. FY05 Benefits Estimates for DER Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.3	0.4	1.4	1.2
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	4	4	3	6
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	9	8	23	30
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	-0.14	0.11	1.04	0.27
Capacity (gigawatts)	6	36	70	99
Total Displaced Need for New Electric Capacity (gigawatts)	26	26	30	63

Federal Energy Management Program

The Federal Energy Management Program (FEMP) aims to improve the overall energy efficiency in Federal Government buildings. As a deployment program, FEMP utilizes a broad spectrum of existing technologies and practices for achieving its goal. Therefore, it does not provide specific technological information in relating costs and energy savings under its activities. The program has a well-documented track record and provided estimates of future savings based on past results and current budgets. The savings by specific energy type projected by the program through the year 2030 are depicted in **Table 5.14**. For the period after 2030, the amount of energy displaced continues at a 2.7% annual growth rate.

Table 5.14. FEMP Annual Energy Savings Projections

Year	Total Primary Energy Displaced (TBtu/yr)	Direct Electricity Displaced (billion kWh/yr)	Direct Natural Gas Displaced (billion CF/yr)	Direct Petroleum Displaced (million barrels/yr)	Direct Coal Displaced (million short tons/yr)
2005	6.444	0.434	1.089	0.070	0.012
2006	12.364	0.860	2.158	0.138	0.023
2007	18.341	1.278	3.207	0.205	0.034
2008	23.346	1.689	4.237	0.271	0.045
2010	32.974	2.486	6.240	0.399	0.067
2015	44.437	3.549	8.942	0.565	0.096
2020	55.408	4.560	11.511	0.723	0.125
2025	67.108	5.521	13.955	0.874	0.151
2030	78.233	6.435	16.279	1.017	0.177

In order to quantify the broader benefits of these savings in MARKAL-GPRA05, a single energy-conservation supply curve was modeled in the FEMP Case to reduce the energy service demands in “miscellaneous” commercial energy demand. The conservation curve was set to reflect the program’s estimated delivered energy savings as shown in **Table 5.14**. Further adjustments were made to the case to roughly match the level of delivered energy savings for each fuel type.

The reduction in commercial energy demand effectively leads to lower investment in the future capacity of demand devices servicing the Federal buildings, resulting in lower energy use in these devices. The reduction in electricity demand also leads to a slight drop in the electric generation by gas-fired power plants. FEMP also directly reduces fossil fuels used in commercial (government) buildings. The long-term systemwide benefits are provided in **Table 5.15**.

Table 5.15. FY05 Benefits Estimates for FEMP (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.08	0.10	0.17	0.17
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	1	1	3	3
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	1.3	1.5	3.3	4.0
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.07	0.09	0.16	0.23

Geothermal Technologies Program

The main goals of the Geothermal Technologies Program are to reduce the cost of conventional geothermal technologies and to develop Enhanced Geothermal Systems (EGS) as a new source of electricity generation.

The Geothermal Technologies Program Case formulated in MARKAL-GPRA05 reflects the program goals for both conventional systems and EGS. For conventional geothermal systems, analysts changed the capital and operating and maintenance (O&M) costs to reflect program goals. However, EGS represents a new geothermal resource not previously represented in the MARKAL-GPRA05 model. The program identified three types of potential geothermal reservoirs:

Type I. Improvement prospects in existing commercial reservoirs
Type II. Identified reservoirs with suboptimal characteristics
Type III. Prospective sites that are not currently identified as hydrothermal prospects

Due to program activities, the capital and O&M costs of EGS systems are projected to decline. **Table 5.16** shows the estimated capital and O&M costs for the three types of EGS systems for 2000 and 2050.

The EGS sites projected under the program are grouped into a set of supply steps, and the discount rate of these technologies is set at 8 percent (instead of 10 percent for the power generation-sector average) to reflect the accelerated depreciation schedule permitted by the Internal Revenue Service for renewable-generation technologies. The EGS systems are modeled as centralized base-load generation.

Table 5.16. EGS Generation Assumptions

EGS Type	Projected Resource MWe	2000 Cost		2050 Cost	
		Capital Cost 2001$/kW	O&M 2001$/kW/yr	Capital Cost 2001$/kW	O&M 2001$/kW/yr
I	3,400	2,448	153	934	50
II	25,000	2,815	176	1,074	58
III	60,000	3,182	199	1,214	66

Geothermal plants compete directly with fossil fuel-based plants for both electricity generation and meeting peak power requirements. In MARKAL-GPRA05, EGS becomes more competitive, as its higher capital cost is offset by increased fossil fuel costs for gas and coal-fired generators, which increase during the projection period as overall fuel demand increases.

The improvements in capital and O&M costs lead to increased market penetration for conventional geothermal-generation capacity. Furthermore, EGS capacity, which was not available in the Baseline Case, shows significant market penetration between 2020 and 2050. **Table 5.17** shows both Baseline Case and Geothermal Technologies Program Case capacity, while **Table 5.18** shows geothermal power generation for both cases.

The projected market penetration of geothermal generation technologies in MARKAL-GPRA05's Geothermal Technologies Program Case directly displaces both natural gas and coal-fired generation beginning in 2010. The long-term benefits are shown in **Table 5.19**.

Table 5.17. Total Geothermal Capacity by Type (gigawatts)

	2000	2010	2020	2030	2040	2050
Baseline Case						
Conventional	2.9	3.3	4.6	6.2	9.4	8.7
EGS	0.0	0.0	0.0	0.0	0.0	0.0
Total	**2.9**	**3.3**	**4.6**	**6.2**	**9.4**	**8.7**
Geothermal Program Case						
Conventional	2.9	5.4	6.4	7.1	11.8	10.4
EGS	0.0	0.0	0.2	6.0	20.0	34.4
Total	**2.9**	**5.4**	**6.6**	**13.0**	**31.7**	**44.8**
Increase						
Conventional	0.0	2.1	1.8	0.9	2.4	1.7
EGS	0.0	0.0	0.2	6.0	20.0	34.4
Total	**0.0**	**2.1**	**2.0**	**6.9**	**22.3**	**36.1**

Table 5.18. Total Geothermal Power Generation by Type (billion kilowatt hours/year)

	2000	2010	2020	2030	2040	2050
Baseline Case						
Conventional	15.0	19.6	30.5	42.2	64.4	59.9
EGS	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.0**	**19.6**	**30.5**	**42.2**	**64.4**	**59.9**
Geothermal Program GPRA Case						
Conventional	15.0	35.4	44.2	49.3	82.6	72.9
EGS	0.0	0.0	1.7	50.6	169.5	292.3
Total	**15.0**	**35.4**	**45.9**	**99.9**	**252.1**	**365.3**
Increase						
Conventional	0.0	15.8	13.6	7.1	18.1	13.0
EGS	0.0	0.0	1.7	50.6	169.5	292.3
Total	**0.0**	**15.8**	**15.3**	**57.7**	**187.7**	**305.4**

Table 5.19. FY05 Benefits Estimates for Geothermal Technologies Program (MARKAL-GPRA05)

Annual Benefits	**2020**	**2030**	**2040**	**2050**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.17	0.42	1.47	2.13
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	2	4	5	9
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	5	9	27	50
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	-0.03	0.16	0.92	0.40
Capacity (gigawatts)	2	7	22	36

Hydrogen, Fuel Cells, and Infrastructure Technologies Program

The Hydrogen, Fuel Cells, and Infrastructure Technologies (HFCIT) Program conducts research and development activities in hydrogen production, storage, and delivery, and transportation and stationary fuel cells. On the demand side, the program's activities focus on the introduction of fuel cells for both stationary and mobile applications. On the supply side, the program goal is to lower the production cost of hydrogen to a competitive level against petroleum products.

The representation of the Hydrogen, Fuel Cells, and Infrastructure Technologies Program in MARKAL-GPRA05 requires representation of fuel cell vehicles and transportation markets, hydrogen production and distribution infrastructure, and stationary fuel cell applications.

Fuel Cell Vehicles and Transportation Markets: Fuel cell vehicles are projected to compete with traditional petroleum and hybrid-electric vehicles for market share in the light-duty vehicle and commercial light truck markets. In MARKAL-GPRA05, analysts measure energy service demands for road transportation in vehicle miles traveled (VMT). Projected VMTs are taken directly from the *Annual Energy Outlook 2003* and extended past 2025, based on historical relationships between passenger and commercial VMTs and population and economic growth. Projected VMTs for cars, light trucks, and commercial light trucks are shown in **Table 5.20**.

Table 5.20. LDV and Commercial Light Truck Vehicle Miles Traveled (billion VMTs/year)

	2000	2010	2020	2030	2040	2050
Total Light-Duty Vehicles	2,355	3,004	3,753	4,417	4,868	5,241
Cars	1,498	1,649	1,992	2,325	2,382	2,288
Light Trucks	857	1,355	1,761	2,092	2,485	2,953
Commercial Light Trucks	69	84	107	134	157	177

For each time period, these demands are met by a mix of vehicle types selected by the model on the basis of total life-cycle costs. The vehicle type is characterized for each model year it is available for purchase. The Baseline Case cost and efficiencies of these vehicles were derived from the *AEO2003* assumptions, with cost and efficiency improvements extrapolated after 2025.

For the Hydrogen Program Case, capital costs, operation and maintenance costs, and fuel efficiency goals were provided by the HFCIT Program for gasoline fuel cell and hydrogen fuel cell vehicles. Assumptions were provided for gasoline fuel cell vehicles for 2010 and 2020, and for hydrogen fuel cell vehicles from 2012 to 2050. As with the Vehicle Technologies Program, these were provided as ratios to conventional gasoline-powered vehicles of the same vintage. For example, a 2020 gasoline-fuel cell passenger car with a cost ratio of 1.20 and an efficiency ratio of 1.8 would cost 20 percent more than the average 2020 traditional gasoline passenger car and have 80 percent higher fuel economy. The cost and efficiency assumptions for passenger cars, sport utility vehicles (SUVs), and commercial light trucks are shown in **Table 5.21**.

Table 5.21. Cost and Efficiency Assumptions for Fuel Cell Vehicles

	2010	2020	2030	2040	2050
Passenger Cars					
Cost Ratio to Conventional					
Fuel Cell (Gasoline)	1.30	1.20			
Fuel Cell (H2)		1.05	1.05	1.05	1.05
Efficiency Ratio to Conventional					
Fuel Cell (Gasoline)	1.50	1.80			
Fuel Cell (H2)		2.50	3.20	3.40	3.40
SUVs & Commercial Light Trucks					
Cost Ratio to Conventional					
Fuel Cell (Gasoline)	1.30	1.20			
Fuel Cell (H2)	1.25	1.05	1.05	1.05	1.05
Efficiency Ratio to Conventional					
Fuel Cell (Gasoline)	1.40	1.80			
Fuel Cell (H2)	2.00	2.50	3.20	3.40	3.40

Hydrogen Production and Distribution Infrastructure: The HFCIT Program conducts research on developing cost-effective hydrogen production technologies from distributed natural gas reformers, as well as a variety of renewable sources, including biomass. For the Hydrogen Case, analysts modeled five hydrogen production technologies: distributed natural gas reformers, central natural gas reformers, central coal gasification, central biomass gasification, and central electrolytic production. Other renewable hydrogen-production technologies were not modeled, due to a greater degree of uncertainty in their costs. Nuclear hydrogen production technologies were also not represented in the MARKAL-GPRA05 model. Carbon sequestration pathways were available for central coal and natural gas hydrogen production. However, because no carbon policies were assumed, producers would not have an economic incentive to incur the incremental cost to sequester carbon generated from hydrogen production activities and, thus, no carbon was sequestered in this Program Case.

HFCIT Program goals were used to estimate capital and O&M costs and production efficiencies for distributed natural gas reformers and central biomass gasifiers and electrolytic production technologies. Assumptions for central coal and natural gas production technologies were adapted from *Hydrogen Production Facilities Plant Performance and Cost Comparisons, Final Report*.[4] The infrastructure requirements and operating costs for the widespread distribution of hydrogen vary widely by distance and method. As a simplifying assumption, a flat cost of $5.28 per MMBtu—or $0.65 per gallon of gasoline equivalent (gge)—was assumed for hydrogen distribution costs based on published data from NREL.[5] (Please note that one kilogram of hydrogen is roughly equivalent in energy content to one gallon of gasoline, and is often referred to as a gallon of gasoline equivalent (gge).) **Table 5.22** shows projected hydrogen costs by cost component for the Hydrogen Program Case.

(Please note that due to market factors affecting feedstock costs, the projected costs may not match HFCIT Program goals.)

Stationary Fuel Cell Applications: In addition to use in vehicles, fuel cells also may be used for distributed electric generation. The HFCIT Program provided cost and performance goals for a 5kW CHP residential fuel cell system and a 200kW CHP commercial fuel cell system. The cost and performance parameters are shown in **Tables 5.23 and 5.24**.

Unlike other program cases, analysts ran the Hydrogen Program Case with both HFCIT and Vehicle Technologies Program assumptions. The rationale for this change is that the hydrogen fuel cell vehicle assumptions provided by the HFCIT Program assume that the Vehicle Technologies Program's hybrid systems and materials technologies R&D activities are successful. The market penetration of hydrogen fuel vehicles is somewhat limited by the increased competition from more-advanced hybrid vehicles. The market shares for LDVs are shown in **Table 5.25**.

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4 *Hydrogen Production Facilities Plant Performance and Cost Comparisons, Final Report*, March 2002, prepared for NETL by Parsons Infrastructure and Technology Group.

5 Amos W.A., Lane J.M., Mann M.K., and Spath P.L. *Update of hydrogen from biomass – determination of the delivered cost of hydrogen*, NREL, 2000.

Table 5.22. Hydrogen Production Costs by Technology and Component (2001 $/gge)

Central Coal								
Unit Costs	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs			$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
O&M			$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Feedstock Costs			$0.22	$0.24	$0.25	$0.27	$0.27	$0.28
Plant Gate			**$0.97**	**$0.99**	**$0.99**	**$1.01**	**$1.02**	**$1.02**
Distribution, Storage & Tax			$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Total			**$2.00**	**$2.02**	**$2.03**	**$2.04**	**$2.05**	**$2.06**
Distributed Natural Gas Reformer								
Unit Costs	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs	$0.73	$0.42	$0.42	$0.42	$0.42			
O&M	$0.53	$0.54	$0.53	$0.54	$0.54			
Feedstock Costs	$0.79	$0.83	$0.84	$0.90	$0.93			
Plant Gate	**$2.05**	**$1.79**	**$1.80**	**$1.86**	**$1.89**			
Tax	$0.38	$0.38	$0.38	$0.38	$0.38			
Total	**$2.43**	**$2.17**	**$2.17**	**$2.24**	**$2.27**			
Central Natural Gas Reformer								
Unit Costs	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs			$0.15	$0.15	$0.15	$0.15	$0.15	
O&M			$0.08	$0.08	$0.08	$0.08	$0.08	
Feedstock Costs			$0.80	$0.86	$0.89	$0.93	$0.97	
Plant Gate			**$1.04**	**$1.10**	**$1.13**	**$1.17**	**$1.21**	
Distribution, Storage & Tax			$1.03	$1.03	$1.03	$1.03	$1.03	
Total			**$2.07**	**$2.13**	**$2.16**	**$2.20**	**$2.24**	
Central Biomass								
Unit Costs	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs		$1.16	$1.02	$0.98	$0.96	$0.95	$0.95	$0.95
O&M		$0.34	$0.31	$0.31	$0.31	$0.31	$0.31	$0.31
Feedstock Costs		$0.35	$0.32	$0.32	$0.32	$0.32	$0.32	$0.32
Plant Gate		**$1.85**	**$1.65**	**$1.61**	**$1.59**	**$1.58**	**$1.58**	**$1.58**
Distribution & Storage*		$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65
Total		**$2.50**	**$2.31**	**$2.26**	**$2.25**	**$2.24**	**$2.23**	**$2.23**
Central Electrolytic Production**								
Unit Costs	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs		$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11
O&M		$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
Feedstock Costs		$2.06	$2.02	$1.99	$2.31	$2.30	$2.21	$1.87
Plant Gate		**$2.37**	**$2.32**	**$2.30**	**$2.61**	**$2.60**	**$2.52**	**$2.17**
Distribution, Storage & Tax		$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Total		**$3.41**	**$3.36**	**$3.33**	**$3.64**	**$3.64**	**$3.55**	**$3.20**

* Note: Hydrogen produced from biomass was assumed to receive preferential tax treatment.
** Central electrolytic production technologies did not penetrate in the Hydrogen Case. The above costs are based on a separate model run where this technology was required to produce.

Table 5.23. 5 kW Residential Combined Heat and Power System Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2001 $/kW)	Maint. Cost (2001$/kW-yr)
2002	2004	0.70	0.30	0.571	$3,000	84.5
2005	2009	0.75	0.32	0.632	$1,500	81.6
2010	2014	0.80	0.35	0.692	$1,000	78.3
2015	2025	0.80	0.35	0.692	$1,000	74.3

Table 5.24. 200 kW Commercial Combined Heat and Power System Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2001 $/kW)	Maint. Cost (2001$/kW-yr)
2002	2004	0.70	0.30	0.571	$2,500	84.5
2005	2009	0.75	0.32	0.632	$1,250	81.6
2010	2014	0.80	0.40	0.667	$750	78.3
2015	2019	0.80	0.40	0.667	$750	74.3
2020	2025	0.80	0.40	0.667	$750	72.5

Table 5.25. Light-Duty Vehicle Market Shares for the Hydrogen Case (% of VMT)

	2000	2010	2020	2030	2040	2050
Gasoline	100%	94%	81%	51%	21%	8%
Hybrid	0%	2%	17%	32%	51%	54%
Hydrogen	0%	0%	1%	13%	27%	38%
Other	0%	4%	1%	4%	1%	0%

Because the Hydrogen Program Case was run with both Hydrogen and Vehicle Technologies Programs' assumptions, analysts could not perform the calculation of benefits through the direct comparison of the Hydrogen Program Case and the Baseline Case. Instead, analysts based the calculation of oil and carbon benefits for the Hydrogen Program on the relative fuel/carbon intensities per vehicle miles traveled (VMTs) of gasoline and hydrogen fuel cell vehicles.

To determine petroleum savings, analysts calculated the average consumption of petroleum products per billion vehicle miles traveled (oil intensity) for light-duty vehicles and commercial light trucks in the Baseline Case. Analysts then multiplied the Baseline Case oil intensity by the VMTs traveled by gasoline fuel cell and hydrogen vehicles in the Hydrogen Program Case to estimate how much oil would be consumed if these VMTs were traveled by traditional gasoline vehicles. Finally, the gasoline consumed by gasoline fuel cell vehicles was subtracted to arrive at the total petroleum savings. These calculations are shown in **Table 5.26**.

Table 5.26. Calculation of Petroleum Savings

	2010	2020	2030	2040	2050
Baseline Case Oil Intensities (TBtu/billion VMT)					
Light-Duty Vehicles	6.59	6.37	6.22	6.12	5.98
Light Trucks	10.90	9.99	9.56	9.37	8.82
Gasoline Fuel Cell Vehicle (VMTs/yr)					
Light-Duty Vehicles	20.00	10.00	135.35	0.00	0.00
Light Trucks	0.00	0.00	0.00	0.00	0.00
Hydrogen Vehicle (VMTs/yr)					
Light-Duty Vehicles	0	45	582	1369	2037
Light Trucks	0	7	15	80	115
Petroleum Savings (TBtu/yr)					
Light-Duty Vehicles	10	290	4,053	8,376	12,186
Light Trucks	0	70	143	749	1,018
Total	**10**	**359**	**4,197**	**9,126**	**13,204**
Total (million barrels per day)	**0.00**	**0.17**	**1.98**	**4.31**	**6.24**

Carbon emission reductions accounted for both the reduced carbon emissions from burning gasoline, as well as increases in carbon emissions from the production of hydrogen, assuming no sequestration. If the hydrogen is produced at central facilities and the resulting carbon is sequestered, then the carbon savings will be accordingly larger in the projections below. These calculations are shown in **Table 5.27**.

Table 5.27. Calculation of Carbon Emission Reduction

	2010	2020	2030	2040	2050
Decreased CO2 Emissions from Decline in Gasoline Consumption					
Decrease in Gasoline Consumption (TBtu/yr)	10	359	4,197	9,126	13,204
Carbon Intensity of Gasoline (MT of Carbon per MMBtu)	19.3	19.3	19.3	19.3	19.3
Decline in Carbon (MMT/yr)	**0.2**	**7.0**	**81.2**	**176.5**	**255.3**
CO2 Emissions from Hydrogen Production					
Production of Hydrogen (TBtu/yr)	n.a.	134	1,196	2,825	4,010
Carbon Intensity of Hydrogen (MT of Carbon per MMBtu)	n.a.	12.2	22.5	25.3	29.2
Increase in Carbon (MMT/yr)	**n.a.**	**1.6**	**27.0**	**71.5**	**117.1**
Net decrease in Carbon Emissions (MMT/yr)	**0.2**	**5.4**	**54.2**	**105.0**	**138.2**

The carbon intensity of hydrogen varies significantly, because of the varying carbon content and market shares of the feedstocks used to produce hydrogen. Hydrogen production by feedstock is shown in **Table 5.28**. It should be noted that this analysis was conducted with a single-region MARKAL-GPRA05 model, and that the price of feedstocks and distribution costs are based on national averages. There is significant variation in regional fuel costs in the United States, and it is likely that during the development of a hydrogen infrastructure, these differences would lead to a greater diversity of hydrogen-production technologies than shown below. Furthermore, this analysis was conducted with only a subset of the full range of hydrogen-production technologies. Thus, this analysis may be biased toward hydrogen production from coal. Future efforts are planned to correct for these modeling limitations.

Table 5.28. Hydrogen Production by Feedstock
(% of total hydrogen production)

	2015	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Central Coal	0%	0%	46%	55%	60%	75%	84%	91%
Remote Natural Gas	100%	84%	33%	22%	12%	0%	0%	0%
Central Natural Gas	0%	0%	6%	7%	8%	6%	4%	0%
Central Biomass	0%	16%	14%	15%	20%	19%	12%	9%

Overall, the Hydrogen, Fuel Cells, and Infrastructure Technologies Program reduces gasoline consumption in the transportation sector through more efficient gasoline fuel cell vehicles and the deployment of hydrogen fuel cell LDVs and commercial light trucks (**Table 5.29**). Furthermore, the reduction in petroleum consumption leads to reduced carbon emissions. However, as noted above, these reductions in carbon emissions are partly offset due to carbon emissions from the production of hydrogen. The reductions in total energy-system costs arise from both the reduction in petroleum imports, as well as associated refining and distribution capacity. However, this is offset somewhat by the cost of establishing the hydrogen-production and -distribution infrastructure.

Table 5.29. FY05 Benefits Estimates for Hydrogen, Fuel Cells, and Infrastructure Technologies Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.2	2.8	6.4	9.2
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	-6	16	51	79
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	5	54	105	138
Security				
Oil Savings (mbpd)	0.2	2.0	4.3	6.2
Natural Gas Savings (quadrillion Btu/yr)	-0.19	-0.56	-0.09	0.40

Industrial Technologies Program

The Industrial Technologies Program (ITP) covers a wide range of technologies, industries, and end-use applications. The overall goal of this program is to increase energy efficiency through R&D, as well as the deployment of new and improved technologies. The heterogeneity of the program's R&D activities makes it difficult to represent program activities explicitly in the MARKAL-GPRA05 framework. Instead, the projected ITP goals by various industries were aggregated into MARKAL-GPRA05 industrial energy-use demand categories as a set of conservation supply curves. Because this approach does not reflect economic competition nor interaction among program technologies, analysts reduced the off-line energy savings by an "integration factor" before these supply curves were constructed and input into the model (**Table 5.30**). The amount of the integration factor is based on how much program overlap or "integration" was captured by the off-line tools. The reduction is based on the expert judgment of the benefits analysis team.

Table 5.30. Industrial Program Integration Factors

Subprogram	Integration Factor
Industries of the Future	15%
Crosscutting R&D	30%
Industrial Assessment Centers	15%
Best Practices[6]	35%

The potential savings represented in these conservation measures are depicted in **Table 5.31**.

The implementation of the conservation curves characterized in the previous section yields an overall reduction in delivered energy consumption, as shown in **Table 5.32**.

The reduction in electricity demand also leads to the reduction in gas-based generation. Both conservation and reduction in electricity demand result in less investment in end-use devices and electric-generation capacity on the supply side (**Table 5.33**).

[6] The Best Practices activity was initially reduced by 50 percent. However, the program revised the Best Practices savings estimate, and the equivalent final reduction is roughly 35 percent.

Table 5.31. Industrial-Sector Conservation Curves (trillion Btu/year)

	2005	2010	2015	2020	2025	2030
Aluminum	0.0	3.9	20.0	43.6	39.1	31.2
Machine Drive						
Step 1	0.0	8.6	41.2	92.2	132.0	187.2
Step 2	0.0	1.2	7.9	26.3	35.5	31.9
Step 3	0.0	4.4	9.6	13.9	14.8	14.8
Step 4	0.0	49.5	70.0	73.4	71.7	71.7
Industrial Steam Heat						
Step 1	0.0	16.7	82.1	187.3	214.5	204.4
Step 2	0.0	7.8	48.2	158.6	205.4	129.0
Step 3	0.0	10.5	21.1	29.6	31.7	32.2
Step 4	0.0	119.4	152.3	153.7	155.6	157.7
Other Industrial Heat						
Step 1	0.0	13.8	64.7	143.4	161.2	149.0
Step 2	0.0	5.3	30.8	98.4	125.0	76.2
Step 3	0.0	7.1	13.5	18.4	19.3	19.0
Step 4	0.0	80.2	97.2	95.3	94.7	93.1
Petrochemicals and Nonenergy Use	0.0	2.9	15.4	43.3	62.0	78.8

Table 5.32. Delivered Energy Savings in the Industrial Sector (trillion Btu/year)

	2010	2015	2020	2025	2030	2040	2050
Petroleum	55	111	164	176	79	100	179
Natural Gas	229	459	854	997	919	919	919
Coal	38	59	74	71	65	61	6
Electricity	68	149	249	293	337	366	398
Heat	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	9
Subtotal	**390**	**778**	**1,341**	**1,537**	**1,399**	**1,446**	**1,493**
Petrochemicals	3	15	43	62	79	83	88
Total	**392**	**794**	**1,385**	**1,599**	**1,478**	**1,529**	**1,581**

Table 5.33. FY05 Benefits Estimates for Industrial Technologies Program (MARKAL-GPRA05)

Annual Benefits	**2020**	**2030**	**2040**	**2050**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	1.9	2.1	2.1	2.2
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	14	13	15	15
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	35	38	34	41
Security				
Oil Savings (mbpd)	0.1	0.1	0.1	0.1
Natural Gas Savings (quadrillion Btu/yr)	1.16	1.12	1.57	1.26
Displaced Capacity (gigawatts)	19	19	18	23

Solar Energy Technologies Program

The Solar Energy Technologies Program covers solar water-heating technologies and photovoltaic (PV)-based electricity generation. The program goal is to lower the cost and improve performance of these technologies.

The Solar Energy Technologies Program Case includes characterization of several solar water heaters with backup systems and PV systems for electricity generation. Analysts base the characterization of solar water heaters for households on the capital cost reductions and reduced reliance on backup fuels as projected in the program objectives. The use of backup fuels is modeled as the percentage of total use. Thus, a 2020 solar water heater would rely on its backup fuel for 45 percent of the time. Analysts assume the efficiency of the backup system to be the efficiency of the least-expensive traditional water heater of the same vintage. Because the MARKAL-GPRA05 model assumes that homes will utilize the same fuel for water heat that is used for space heat, it was assumed that solar water heaters could use natural gas, electricity, and heating oil as the backup fuel.

Analysts modeled both centralized and decentralized PV power systems. The capital cost and O&M costs for both units are reduced to meet program goals. In addition, analysts set the discount rates of these technologies at 8 percent (instead of the industrial average of 10 percent) to reflect the accelerated depreciation schedule available for renewable-generation technologies. The total installed capacity of the decentralized units reflects the Million Solar Roofs installation goals for reducing end-use electricity demand from the central grid. Analysts model the centralized PV-generating systems to compete with conventional fossil fuel-based power plants. To reflect uncertainty in the availability of the solar resource, the potential contribution from these systems to meeting peak power demand is limited to 50 percent of installed capacity for central systems and 30 percent for distributed systems. This disadvantages PV in competing with fossil fuel-based plants, because additional reserve capacity is needed for PV systems. The cost and performance characteristics of the Solar Energy Technologies Program Case for water heaters and PV systems are shown in **Table 5.34**.

Likewise, solar photovoltaic capacity increases dramatically over the Baseline Case (**Table 5.36**). By 2050, the Solar Energy Technologies Program Case shows an additional 25.3 GW of photovoltaic capacity over the Baseline Case. However, potential improvements in central solar-thermal generation were not included in this analysis. Consequently, photovoltaics displace two GW of central solar-thermal capacity.

Central PV-generation technologies in the Solar Energy Technologies Program Case directly displace central gas-fired generation capacity. However, because of the solar technologies' lower availability factor and reduced contribution to peak power supply, the total gas capacity replaced is less than the installed solar capacity. Solar water heaters and rooftop PV reduce fuel use in residential water heating and end-use electricity demand from the central grid, reducing fossil fuel use, carbon emissions, and overall energy system cost. Benefits estimates for the Solar Energy Technologies Program are shown in **Table 5.37**

Table 5.34. Solar Program Technology Assumptions

Photovoltaics

Year	Central Generation Installed Price (2001$/kW)	Central Generation O&M (2001$/kW)	Residential Buildings Installed Price (2000$/kW)	Residential Buildings O&M (2000$/kW)	Commercial Buildings Installed Price (2000$/kW)	Commercial Buildings O&M (2000$/kW)
2003	5,300	60	9,450	160	6,250	160.0
2007	3,600	40	6,250	40	4,500	40.0
2020	2,000	10	2,800	10	2,800	10.0
2025	1,700	9	2,380	9	2,380	8.5
2030	1,445	7	2,023	7	2,023	7.2
2035	1,228	6	1,720	6	1,720	6.1
2040	1,105	6	1,548	6	1,548	5.5
2050	1,050	5	1,470	5	1,470	5.3

Solar Water Heaters

Vintage	Installed Cost	Backup Fuel Use
2000	2,300	50%
2010	2,000	48%
2020	1,000	45%
2030	680	36%
2040	680	33%

Table 5.35. Solar Water-Heater Market Share by Backup Fuel (% of total market)

	2000	2010	2020	2030	2040	2050
Electric	0%	0%	0%	8%	22%	21%
Natural Gas	0%	0%	0%	0%	11%	19%
Oil	0%	0%	0%	2%	13%	10%
Total	**0%**	**0%**	**0%**	**10%**	**46%**	**51%**

Table 5.36. Solar-Generation Capacity by Case and Type (gigawatts)

	2000	2010	2020	2030	2040	2050
Baseline Case						
Central Thermal	0.3	0.4	0.5	0.6	2.1	2.0
Central PV	0.0	0.1	0.3	2.9	8.8	8.7
Distributed PV	0.0	0.1	0.1	0.0	0.0	0.0
Total	**0.3**	**0.6**	**0.9**	**3.5**	**10.9**	**10.6**
Solar Program Case						
Central Thermal	0.3	0.4	0.5	0.4	0.2	0.0
Central PV	0.0	0.5	1.8	5.5	11.1	13.0
Distributed PV	0.0	0.8	4.0	9.1	21.5	21.0
Total	**0.3**	**1.8**	**6.2**	**15.0**	**32.7**	**34.0**
Increase						
Central Thermal	0.0	0.0	0.0	-0.1	-2.0	-2.0
Central PV	0.0	0.4	1.5	2.5	2.3	4.3
Distributed PV	0.0	0.7	3.9	9.1	21.5	21.0
Total	**0.0**	**1.1**	**5.4**	**11.5**	**21.8**	**23.4**

Table 5.37. FY05 Benefits Estimates for Solar Energy Technologies Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.11	0.41	1.51	1.61
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	0.2	0.1	0.3	0.3
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	1	5	22	29
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.22	0.33	1.41	1.16
Capacity (gigawatts)	5	11	22	23

Vehicle Technologies Program

The Vehicle Technologies Program[7] consists of Hybrid Systems R&D, Advanced Combustion R&D, Heavy Systems R&D, and Materials Technologies R&D. The general goal of these R&D activities is to improve the efficiency and lower the cost of road vehicles.

Energy service demands for road transportation are measured in vehicle miles traveled (VMT). Projected VMTs are taken directly from the *Annual Energy Outlook 2003 (AEO 2003)* and extended past 2025 based on historical relationships between passenger and commercial VMTs, and population and economic growth. Projected VMTs for cars, light trucks[8], commercial light trucks,[9] and heavy trucks are shown in **Table 5.38**.

Table 5.38. Projected Vehicle Miles Traveled by Vehicle Class (billion VMTs/year)

Vehicle Class	2000	2010	2020	2030	2040	2050
Light-Duty Vehicles	2,355	3,004	3,753	4,417	4,868	5,241
Cars	1,498	1,649	1,992	2,325	2,382	2,288
Light Trucks	857	1,355	1,761	2,092	2,485	2,953
Commercial Light Trucks	69	84	107	134	157	177
Heavy Trucks	207	263	338	422	493	544

For each time period, these demands are met by a mix of vehicle types, selected by the model on the basis of total life-cycle costs. The vehicle type is characterized for each model year that it is available for purchase. The Baseline Case cost and efficiencies of these vehicles were derived from the *AEO2003* assumptions, with cost and efficiency improvements extrapolated for periods after 2025.

For the Vehicle Technologies Program Case, the costs and efficiencies for hybrid (HEV) and advanced diesel vehicles were changed for passenger cars, sport utility vehicles (SUVs),

[7] The Vehicle Technologies Program is run by the Office of FreedomCAR and Vehicle Technologies.
[8] Light trucks include trucks with a gross vehicle weight under 8,500 pounds and may include pickups, vans, or sport utility vehicles (SUVs).
[9] Commercial light trucks are light trucks with a gross vehicle weight between 8,500 and 10,000 pounds and may include pickups, vans, or SUVs.

commercial light trucks, and commercial heavy trucks. These changes reflect the results of the fuel combustion, hybrid systems, and materials R&D activities. Alternate cost and efficiency assumptions were provided for gasoline and diesel hybrid vehicles, as well as advanced diesel engines for use in passenger cars, SUVs, and commercial light trucks for the period 2010 to 2050. Cost and efficiency assumptions for diesel hybrid Class 3-6 trucks and advanced diesel Class 7-8 trucks also were provided for the period 2010 to 2040. The cost and efficiency assumptions were provided from the off-line analysis as ratios to conventional gasoline or diesel internal combustion engine-powered vehicles of that vintage. For example, a 2020 gasoline-hybrid passenger car with a cost ratio of 1.05 and an efficiency ratio of 1.7 would cost 5 percent more than the average 2020 traditional gasoline passenger car and have 70 percent better fuel economy. The cost and efficiency assumptions for passenger cars, SUVs, and commercial light trucks are shown in **Table 5.39**, while **Table 5.40** shows these assumptions for heavy trucks.

Table 5.39. Cost and Efficiency Assumptions for Light Duty Vehicles

	2010	2020	2030	2040	2050
Passenger Cars					
Cost Ratio to Conventional in Same Year					
Gasoline HEV	1.09	1.05	1.03	1.02	1.01
Advanced Diesel	1.07	1.04	1.02	1.02	1.02
Diesel HEV	1.12	1.07	1.05	1.04	1.04
Efficiency Ratio to Conventional in Same Year					
Gasoline HEV	1.50	1.70	1.90	2.00	2.00
Advanced. Diesel	1.40	1.50	1.50	1.60	1.60
Diesel HEV	1.70	1.90	2.10	2.19	2.27
Light Trucks and SUVs					
Cost Ratio to Conventional in Same Year					
Gasoline HEV	1.10	1.06	1.04	1.03	1.02
Advanced Diesel	1.08	1.05	1.03	1.02	1.02
Diesel HEV	1.13	1.09	1.07	1.06	1.05
Efficiency Ratio to Conventional in Same Year					
Gasoline HEV	1.35	1.50	1.60	1.62	1.64
Advanced Diesel	1.40	1.45	1.50	1.60	1.60
Diesel HEV	1.50	1.75	1.80	1.81	1.82

Table 5.40. Cost and Efficiency Assumptions for Heavy Trucks*

	2010	2020	2030	2040
Class 7-8 - Diesel				
Efficiency Ratio	1.03	1.18	1.31	1.33
Cost Ratio	1.05	1.02	1.01	1.01
Class 3-6 - Diesel Hybrid				
Efficiency Ratio	1.09	1.34	1.62	1.67
Cost Ratio	1.04	1.01	1.01	1.01

* Note: Ratios are compared to conventional vehicles in the same year.

The oil savings generated from the Vehicle Technologies Program are attributable to the market penetration of more efficient LDVs and heavy trucks. **Table 5.41** shows the market shares for traditional gasoline and alternative light-duty vehicles for the Vehicle Technologies Program Case, while **Table 5.42** shows transportation-sector petroleum consumption for the Baseline and Vehicles Technologies Program Case.

The reduction in transportation-sector petroleum consumption (**Table 5.43**) is due to both increased market share and fuel efficiency of alternative vehicles, particularly hybrid-electric vehicles. The reductions in total energy-system costs arise from both the reduction in petroleum imports, as well as associated refining and distribution capacity.

Table 5.41. Light-Duty Vehicle Market Shares for the Vehicles Technologies Program Case (% of total fleet)

	2000	2010	2020	2030	2040	2050
Gasoline	100%	93%	84%	63%	22%	0%
Hybrid	0%	3%	15%	36%	77%	100%
Advanced Diesel and Other	0%	3%	1%	0%	0%	0%

Table 5.42. Petroleum Consumption by Vehicle Class and Case (trillion Btu/year)

	2000	2010	2020	2030	2040	2050
Baseline Case						
Light-Duty Vehicles	14,826	19,801	23,911	27,469	29,789	31,350
Commercial Light Trucks	654	916	1,069	1,279	1,468	1,559
Heavy Trucks	4,215	5,549	7,065	8,002	9,255	10,014
Vehicle Technologies Program Case						
Light-Duty Vehicles	14,826	19,540	22,802	23,512	20,141	18,339
Commercial Light Trucks	654	977	1,012	1,214	1,070	1,110
Heavy Trucks	4,215	5,549	6,905	6,303	7,006	7,500
Savings						
Light-Duty Vehicles	0	261	1,108	3,957	9,648	13,011
Commercial Light Trucks	0	-62	57	64	397	449
Heavy Trucks	0	0	159	1,699	2,249	2,514
Total Transportation Sector	0	199	1,325	5,720	12,295	15,974

Table 5.43. FY05 Benefits Estimates for Vehicle Technologies Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	1.31	5.88	12.36	16.24
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	18	25	83	150
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	25	117	241	317
Security				
Oil Savings (mbpd)	0.6	2.8	5.8	7.6
Natural Gas Savings (quadrillion Btu/yr)	-0.03	-0.30	-0.03	0.03

The Weatherization and Intergovernmental Program

The Weatherization and Intergovernmental Program (WIP) Case formulated in MARKAL-GPRA05 focuses on deployment programs that have impact on the energy consumption in the residential sector and vehicle fuel use. Projected program goals of the Weatherization Assistance

Program, Rebuild America, and Code Training and Assistance are transformed into conservation-supply curves that reduce the heating and cooling loads in households benefiting from these programs. **Table 5.44** depicts the projected funds and program goals of the Weatherization Assistance Program used to develop the MARKAL-GPRA05 input.

The aggregated conservation supply curves estimated for MARKAL-GPRA05 (**Table 5.45**) are consistent with the potential savings projected in NEMS. Analysts distributed the aggregated market potentials in proportion to household savings in the four MARKAL-GPRA05 residential regions: Northeast, Midwest, South, and West.

Table 5.44. Weatherization Assistance Program Projected Budget and Goals[10]

Year	Funds for Houses	Cost per House	No. Houses Weatherized	Annual Total Houses Weatherized	SITE Energy Savings (TBtu/yr)	Single-Family Home Savings (TBtu/yr)	Mobile Home Savings (TBtu/yr)	Multi-family Home Savings (TBtu/yr)
2005	$ 531,640,642	$ 2,391	222,395	222,395	6.97	4.46	1.39	1.12
2010	$ 569,455,081	$ 2,463	231,243	1,360,565	42.68	27.31	8.54	6.83
2015	$ 577,584,873	$ 2,478	233,119	2,526,161	79.28	50.74	15.86	12.68
2020	$ 577,584,873	$ 2,478	233,119	3,469,363	108.91	69.7	21.78	17.43
2025	$ 577,584,873	$ 2,478	233,119	3,496,788	109.81	70.28	21.96	17.57
2030	$ 577,584,873	$ 2,478	233,119	3,496,788	109.81	70.28	21.96	17.57

Table 5.45. Residential-Sector Conservation Curves (trillion Btu/year)

	2010	2020	2030	2040	2050
Heating	40.6	97.5	129.9	136.0	140.4
Cooling	0.0	0.0	27.0	28.6	29.6

In addition to the heating and cooling supply curves, the compact fluorescent light (CFL) technology included in these programs is specifically modeled in MARKAL-GPRA05 to compete with the conventional incandescent light in households. The deployment of CFL is achieved by lowering the Baseline Case hurdle rate of 44 percent to the normal rate of 18 percent. An upper bound of CFL's market penetration is imposed to reflect the program goals of increasing the market share of lighting service demand met by CFL. This increasing trend of CFL's market share is projected to continue in the long run (**Table 5.46**).

Table 5.46. Compact Florescent Market Penetration (10^{12} lumen-second)

	2010	2020	2030	2040	2050
Penetration	2,456	9,045	14,726	18,395	20,828

Analysts modeled the Clean Cities Program based on program estimates of alternative-fueled vehicle market penetration, as shown in **Table 5.47**. These vehicles were then allocated to different vehicle classes and fuel types by the breakdown of the 2002 fleet (**Table 5.48**).

[10] See Appendix K for additional documentation on these goals.

Table 5.47. Projection of Baseline Case and Clean Cities Program Case Alternative-Fueled Vehicles (number of vehicles on the road)

	Baseline Case	Program Case	Additional Vehicles due to Program
2000	321,495	432,344	n.a.
2005	337,894	566,709	228,815
2010	355,130	723,431	368,301
2015	373,245	936,661	563,415
2020	392,284	1,230,259	811,353
2025	412,295	1,638,871	1,194,843

Table 5.48. Alternative-Fueled Vehicles by Type and Class, 2002

	Total	LDV	% of LDV	HDV	% of HDV
CNG	66,197	55,923	45%	10,274	38%
LNG	2,158	88	0%	2,070	8%
Propane	29,203	24,027	19%	5,176	19%
Ethanol	29,229	29,173	24%	56	0%
Electric	4,244	3,935	3%	309	1%
Biodiesel	16,970	7,806	6%	9,164	34%
Methanol	787	771	1%	16	0%
Neighborhood Electric	1,955	1,955	2%	0	0%
Other	485	430	0%	55	0%
Total	**151,228**	**124,108**	**100%**	**27,120**	**100%**

The program goals of Inventions and Innovations and the State Energy Program were not modeled in the WIP Program Case, because of insufficient data to develop the input required in MARKAL-GPRA05. **Tables 5.49 and 5.50** depict the energy savings by end-use demand and fuel type in the residential sector mainly due to the Weatherization Assistance Program and CFL modeled in MARKAL-GPRA05.

Table 5.51 reports the change of fuel mix in transportation fuel generated from the use of Clean Cities Vehicles. It is highlighted by the penetration of natural gas (CNG) as a transportation to replace gasoline and diesel fuels.

Table 5.49. Delivered Energy Demand Reductions in the Residential Sector (trillion Btu/year)

	2010	**2020**	**2030**	**2040**	**2050**
Reductions by Demand Service					
Space Heating	38	85	182	157	172
Space Cooling	-1	-2	10	8	8
Water Heating	4	15	23	2	3
Lighting	100	191	184	160	106
Other	0	0	0	0	0
Total	**140**	**290**	**400**	**328**	**288**
Reduction by Fuel					
Petroleum	-6	-1	38	55	85
Natural Gas	19	71	189	103	99
Coal	19	3	2	0	2
Electricity	109	216	170	170	104
Total	**140**	**290**	**400**	**328**	**289**

Table 5.50. Delivered Energy Demand Reductions in the Commercial Sector (trillion Btu/year)

	2010	2020	2030	2040	2050
Reductions by Demand Service					
Space Heating	-3	-1	3	0	-9
Space Cooling	0	0	1	0	1
Water Heating	0	0	0	0	0
Lighting	1	2	2	2	2
Other	0	0	0	0	0
Total	**-3**	**1**	**6**	**2**	**-7**
Reduction by Fuel					
Petroleum	0	1	0	0	0
Natural Gas	-15	-7	-10	0	8
Coal	0	0	0	0	0
Electricity	12	7	15	2	-15
Total	**-3**	**1**	**6**	**2**	**-7**

Table 5.51. Reduction in Fuel Consumption in the Transportation Sector (trillion Btu/year)

	2010	2020	2030	2040	2050
Petroleum	-32	17	84	249	581
Gasoline	-32	-40	-17	75	330
Distillate	0	64	114	190	291
Jet Fuel	0	0	0	0	0
LPG	0	-6	-12	-16	-40
Residual Fuel	0	0	0	0	0
Natural Gas	28	-38	-113	-262	-569
Ethanol	-2	-4	-9	-20	-45
Total	**-6**	**-26**	**-38**	**-36**	**-33**

The reduction in electricity demand in residential space conditioning and lighting also leads to the reduction in gas-based generation in the long run. Both conservation and reduction in electricity demand result in fewer investments in end-use devices and electric-generation capacity on the supply side. This is another factor attributable to the overall reduction in energy-system cost and carbon emissions, in addition to direct energy savings (**Table 5.52**).

Table 5.52. FY05 Benefits Estimates for Weatherization and Intergovernmental Program (MARKAL-GPRA05)

Annual Benefits	**2020**	**2030**	**2040**	**2050**
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.8	0.6	0.5	0.5
Economic				
Energy System Cost Savings (billion 2001 dollars/yr)	4	5	6	5
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	16	9	10	12
Security				
Oil Savings (mbpd)	0.0	0.1	0.1	0.3
Natural Gas Savings (quadrillion Btu/yr)	0.37	0.43	0.20	-0.45
Displaced Capacity (gigawatts)	6	6	6	2

Wind and Hydropower Technologies Program

The goal of the wind component under the Wind and Hydropower Technologies Program is to reduce the cost and improve the performance of wind generators. The Hydropower Program seeks to reduce the environmental impact of hydroelectric facilities through improved turbine design and operating practices. Reducing the environmental impact of these facilities ensures that they will be relicensed, maintaining overall hydroelectric-generating capacity.

The Wind Program R&D aims to reduce capital and O&M costs and improve capacity factors for wind turbines. The program goals are represented in the MARKAL-GPRA05 model by changing the capital and O&M costs and capacity factors for wind turbines to coincide with the program goals as represented in **Table 5.53**.

Table 5.53. Wind-Power Assumptions

	2010	2020	2030	2040	2050
Capital Costs with Contingency Factor (2003 $/kW)					
Class 6	$910	$835	$803	$781	$760
Class 5	$910	$835	$803	$781	$760
Class 4	$1,017	$936	$899	$877	$856
Fixed O&M Cost ($/kW/year)	8.0	7.6	7.6	7.6	7.6
Capacity Factor					
Class 6	50%	51%	52%	52%	52%
Class 5	44%	46%	46%	46%	46%
Class 4	39%	47%	47%	47%	47%

The discount rate for wind generators is set at 8 percent (instead of the utility average of 10 percent) to reflect the accelerated depreciation schedule available for renewable-generation technologies. Wind generators are modeled as centralized plants to compete with fossil fuel-based plants. The potential contribution of wind systems to meeting peak power demand is limited to 40 percent, reflecting the intermittent nature of the technology. As with PV systems, this disadvantages wind generators, as additional reserve capacity is needed to meet peak power requirements. However, this disadvantage is offset by the reduction in capital cost and performance improvements projected for wind technologies by the program. As a result, wind generators near the central grid are very competitive with fossil fuel-based power plants.

For the Hydropower Program, the projected capacity and electricity output represented in the MARKAL-GPRA05 Baseline Case was reduced from the *AEO2003* reference projection levels to account for the reduction in capacity and generation resulting from environmental concerns during the relicensing process. These reductions were taken from program estimates and indicate that a total of 4.7 GW of hydro capacity and 19.7 billion kWh of hydro generation would be lost between 2000 and 2010. For the Hydropower Technologies Program Case, it was assumed that, due to improved turbines, no hydro capacity would be lost through the relicensing process; and that improved operations would result in an additional 1.1 billion kWh of hydrogenation in 2010 and 5.3 billion kWh in 2020 to *AEO2003* levels.

The improvements in wind turbines result in a significant increase in installed wind generation capacity over the Baseline Case. Total wind generation increases due to both the increase in total installed capacity and the increase in capacity factors. The change in wind capacity and generation is shown in **Table 5.54**.

For the Hydopower Program, total hydropower capacity returns to *AEO2003* levels, while improved operations result in additional hydropower generation. These results are shown in **Table 5.55**.

In the Wind and Hydropower Technologies Program Case, wind and hydropower generation directly displaces gas-fired and coal-based generation. However, because of wind's lower availability and reduced contribution to peak, the total gas and coal generation capacity replaced is less than the wind capacity installed.

Table 5.54. Total Wind Capacity and Generation

	2000	2010	2020	2030	2040	2050
Wind Capacity (GW)						
Baseline Case	4.0	7.1	10.3	23.0	53.6	66.1
GPRA Case	4.0	12.1	37.4	73.0	114.5	186.7
Increase	**0.0**	**5.0**	**27.1**	**50.1**	**60.9**	**120.6**
Wind Generation (Billion kWh/year)						
Baseline Case	11.2	22.4	35.9	83.1	193.2	240.2
GPRA Case	11.2	40.4	149.9	296.6	467.1	763.0
Increase	**0.0**	**18.0**	**114.0**	**213.5**	**273.9**	**522.8**
Wind % of Total Capacity						
Baseline Case	0.5%	0.7%	0.9%	1.6%	3.5%	3.8%
GPRA Case	0.5%	1.3%	3.2%	5.1%	7.4%	10.2%
Wind % of Total Generation						
Baseline Case	0.3%	0.5%	0.7%	1.3%	2.7%	2.9%
GPRA Case	0.3%	0.9%	2.7%	4.7%	6.5%	9.3%

Table 5.55. Total Hydropower Capacity and Generation

	2000	2010	2020	2030	2040	2050
Total Capacity (GW)						
Baseline Case	79.0	74.3	74.3	74.3	74.3	74.3
GPRA Case	79.0	79.0	79.0	79.0	79.0	79.0
Increase	**0.0**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**
Total Generation (Billion kWh/year)						
Baseline Case	301.7	282.0	280.7	280.7	280.7	280.7
GPRA Case	301.7	302.9	307.0	307.0	307.0	307.0
Increase	**0.0**	**20.8**	**26.3**	**26.3**	**26.3**	**26.3**

The estimated benefits of for the Wind and Hydropower Programs are shown in **Tables 5.56 and 5.57**, respectively.

Table 5.56. FY05 Benefits Estimates for Wind Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	1.21	1.81	2.34	4.01
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	3	4	6	6
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	26	35	46	85
Security				
Oil Savings (mbpd)	ns	ns	0.1	ns
Natural Gas Savings (quadrillion Btu/yr)	0.49	0.84	1.31	1.56
Capacity (gigawatts)	27	50	61	121

Table 5.57. FY05 Benefits Estimates for Hydropower Program (MARKAL-GPRA05)

Annual Benefits	2020	2030	2040	2050
Energy Displaced				
Nonrenewable Energy Savings (quadrillion Btu/yr)	0.27	0.22	0.23	0.24
Economic				
Energy-System Cost Savings (billion 2001 dollars/yr)	2	2	2	2
Environmental				
Carbon Savings (million metric tons carbon equivalent/yr)	4	3	3	3
Security				
Oil Savings (mbpd)	ns	ns	ns	ns
Natural Gas Savings (quadrillion Btu/yr)	0.26	0.20	0.23	0.25
Capacity (gigawatts)	5	5	5	5

Box 5.1—The MARKAL Model

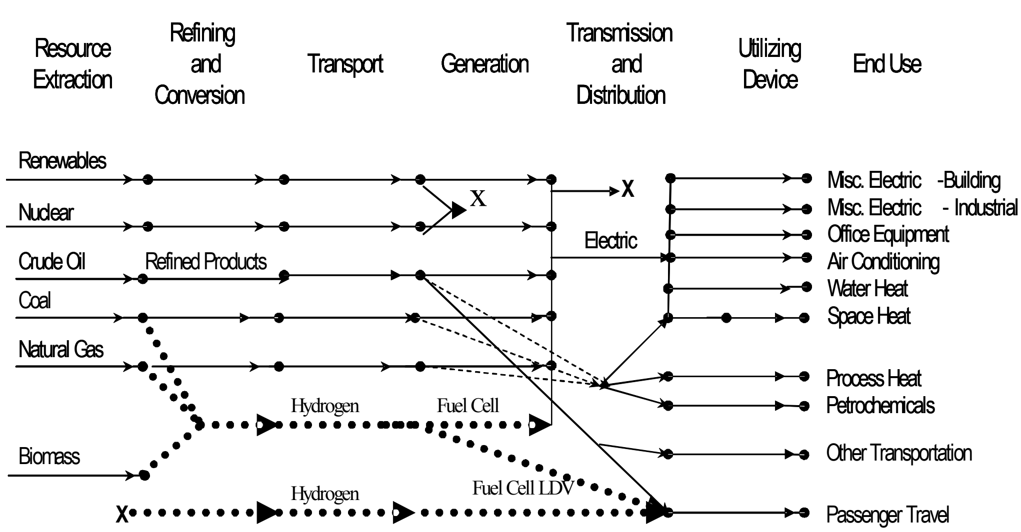
The U.S. MARKAL model is a technology-driven linear optimization model of the U.S. energy system that runs in five-year intervals over a 50-year projection period. MARKAL provides a framework to evaluate all resource and technology options within the context of the entire energy/materials system, and captures the market interaction among fuels to meet demands (*i.e.*, competition between gas and coal for electric generation). The model explicitly tracks the vintage structure of all capital stock in the economy that produces, transports, transforms, or uses energy.

In MARKAL, the entire energy system is represented as a network, based on the reference energy system (RES) concept. The RES depicts all possible flows of energy from resource extraction, through energy transformation, distribution, and transportation; to end-use devices that satisfy the demands of useful energy services (e.g., vehicle miles traveled, lumen-second in lighting). **Figure 5.2** illustrates a simplified RES in graphical form. The U.S. MARKAL has detailed technical representations of four end-use sectors (residential, commercial, industrial, and transportation), as well as fossil fuel and renewable resources, petroleum refining, power generation, hydrogen production, and other intermediate conversion sectors. Cross comparisons of MARKAL outputs provide detailed technical and economic information to use in estimating the programs' benefits.

Technology choice in the MARKAL framework is based on the present value of the marginal costs of competing technologies in the same market sector. On the demand side, the marginal cost of demand devices is a function of levelized capital cost, O&M cost, efficiency, and the imputed price of the fuel used by these devices. For a specific energy-service demand and time period, the sum of the energy-service output of competing technologies has to meet the projected demand in that period. The relative size of the energy-service output (market share) of these technologies depends not only on their individual characteristics (technical, economic, and environmental), but also on the availability and cost of the fuels (from the supply side) they use. The actual market size of a demand sector in a future time period depends on the growth rate of the demand services and the stock turnover rate of vintage capacities. MARKAL dynamically tracks these changes and defines future market potentials. Another factor considered in MARKAL, which affects the market penetration of a specific demand device, is the sustainability of the expansion in the implied manufacturing capacity to produce these devices. For EERE R&D programs that have independently projected the market potentials of their technologies, an initial market penetration (combined with an annual growth rate limit) was imposed in MARKAL to replicate these potentials for assessing the benefits of these technologies.

On the supply side, technology choice made in MARKAL is based on the imputed price of the energy products and the marginal cost of using these products downstream in the demand sectors. The cost of resource input for production (exogenously projected in MARKAL) such as imported oil prices and cost of biomass feedstock, together with the characteristics of supply technologies (including electricity generation) determine the market share of a particular fuel type (including renewables) and the technology that produces it. The supply-demand balance achieved for all fuels under the least energy-system cost represents a partial equilibrium in the energy market.

Figure 5.2. An Illustrative Reference Energy System



Appendix A – GPRA05 Benefits Estimates: MARKAL and NEMS Model Baseline Cases

MARKAL Baseline Case: Assumptions and Projections

Economic and Demographic Assumptions

The Baseline Case projection used to evaluate the impact of the EERE portfolio was benchmarked to the Energy Information Administration's (EIA) *2003 Annual Energy Outlook* (AEO) for the period between 2000 and 2025. To the extent possible, the same input data and assumptions were used in MARKAL (market allocation model) as were used to generate the AEO reference case. For example, the macroeconomic projections for gross domestic product (GDP), housing stock, commercial square footage, industrial output, and vehicle miles traveled (VMTs) were taken from the AEO. At the sector level, both supply-side and demand-side technologies were characterized to reflect the AEO assumptions, in cases where the representation of technologies is similar between MARKAL and the National Energy Modeling System (NEMS). The resulting projections track closely with the AEO at the aggregate level, although they do not match exactly at the end-use level. For the period after 2025, various sources were drawn upon to compile a set of economic and technical assumptions. The primary economic drivers of GDP and population were based on the real GDP growth rate from the Congressional Budget Office's Long-Term Budget Outlook and population growth rates from the Social Security Administration's 2002 Annual Report to the Board of Trustees.

In the Baseline Case, GDP is projected to increase at an average annual rate of 2.9 % 2000 to 2025, and then slow to an average annual rate of 2.3 % from 2025 to 2050. The population growth rate is projected to decline from an average annual rate of 0.8 % between 2000 and 2025 to 0.5 % from 2025 to 2050. The Baseline Case macroeconomic assumptions are shown in **Table 1.**

Table 1. Baseline Case Macroeconomic and Demographic Assumptions

												Annual Growth Rates		
	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'00-'25	25-'50	'00-'50
GDP (Bill. 2001$)	$10,052	$11,332	$13,407	$15,627	$17,991	$20,690	$23,582	$26,728	$29,694	$32,990	$36,246	2.9%	2.3%	2.6%
Population (Million)	275.3	287.7	299.9	312.3	324.9	337.8	347.8	358.0	365.6	373.4	379.4	0.8%	0.5%	0.6%
Total Households (Million)	105.2	110.8	117.2	123.5	128.8	134.3	135.9	139.8	142.8	145.9	148.2	1.0%	0.4%	0.7%
Commercial Floorspace (Bill. sq ft)	68.5	76.1	81.8	88.2	94.6	101.1	108.9	116.9	124.0	131.6	138.8	1.6%	1.3%	1.4%
Industrial Production (2000=100)	100	103	122	140	157	177	198	219	242	265	290	2.3%	2.0%	2.2%
Light Duty Vehicle Miles Traveled (Bill. VMT)	2,355	2,642	3,004	3,380	3,753	4,132	4,475	4,721	4,980	5,168	5,362	2.3%	1.0%	1.7%

Assumptions on Energy Prices

Table 2 shows projected energy prices for the reference case. Natural gas prices are projected to drop between 2000 and 2005, and then increase at about 1.5 % per year from 2005 to 2025, before increasing amounts of arctic gas and liquefied natural gas (LNG) imports limit the average annual increase to 1.1 % from 2025 to 2050. Crude oil prices are also projected to decrease between 2000 and 2005, increase at average annual rates of 0.6 % between 2005 and 2025, and 0.8 % per year thereafter.

Average mine-mouth coal prices are projected to continue to decline by about 0.6 % a year between 2000 and 2025 due to increasing productivity gains and a continued shift to less labor-intensive Western coal production. However, coal prices are projected to increase at an average rate of 1.1 % per year after 2025, due to increased demands, gradually increasing mine depths and a saturation of labor productivity gains.

Table 2. Baseline Case Energy Prices

												Annual Growth Rates		
2001 $s	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'00-'25	25-'50	'00-'50
World Oil Price ($/bbl)	$28.36	$23.58	$23.96	$24.71	$25.40	$26.66	$27.98	$29.11	$30.75	$31.56	$32.82	-0.2%	0.8%	0.3%
Natural Gas Wellhead Price ($/Mcf)	$3.83	$2.88	$3.33	$3.59	$3.73	$3.86	$4.10	$4.35	$4.71	$4.80	$5.05	0.0%	1.1%	0.6%
Coal Minemouth Price ($/short ton)	$17.05	$16.41	$14.76	$14.60	$14.32	$14.47	$15.29	$16.08	$16.56	$17.93	$19.33	-0.7%	1.2%	0.3%
Average Wholesale Electricity Price (¢/kWh)	4.0¢	3.9¢	4.4¢	4.6¢	4.8¢	4.4¢	4.6¢	4.9¢	5.0¢	4.8¢	4.6¢	0.4%	0.2%	0.3%

Primary Energy Consumption

As a result of slightly increasing energy prices, technology improvements, and shifts within the economy, energy demand is projected to increase more slowly than GDP. As shown in **Table 3**, total primary energy use is projected to increase at a rate of 1.4 % per year from 2000 to 2025, and at an average annual rate of 0.6 % between 2025 and 2050. By 2050, total primary energy consumption is projected to reach 163 quadrillion Btus (quads). Overall, the energy consumption to GDP ratio is projected to decline by 1.5 % per year from 2000 to 2050, while total carbon emissions increase by 1.1 % per year during the same period.

Table 3. Primary Energy Consumption, Energy Intensity, and Carbon Emissions

												Annual Growth Rates		
	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'00-'25	25-'50	'00-'50
Petroleum	37.5	39.9	44.6	48.9	52.7	56.9	59.7	62.6	65.0	67.1	68.9	1.7%	0.8%	1.2%
Natural Gas	23.3	24.9	28.1	30.6	33.2	35.2	38.7	41.4	43.6	45.0	46.6	1.7%	1.1%	1.4%
Coal	22.5	23.3	25.2	26.6	28.3	29.8	29.0	29.7	30.6	31.8	32.8	1.1%	0.4%	0.8%
Nuclear	7.9	8.6	8.7	8.7	8.7	8.7	7.6	6.1	5.2	3.4	1.6	0.4%	-6.5%	-3.1%
Renewables	7.2	7.8	7.8	8.2	8.6	9.1	9.8	11.3	12.5	12.9	12.9	1.0%	1.4%	1.2%
Total Primary Energy	**98.3**	**104.5**	**114.3**	**123.0**	**131.5**	**139.8**	**144.7**	**151.1**	**156.8**	**160.1**	**162.8**	**1.4%**	**0.6%**	**1.0%**
Energy/GDP (Thos. Btu/ '01$ GDP)	9.8	9.2	8.5	7.9	7.3	6.8	6.1	5.7	5.3	4.9	4.5	-1.5%	-1.6%	-1.5%
Carbon Emissions (MMT)	1,564	1,657	1,835	1,983	2,130	2,274	2,347	2,454	2,549	2,634	2,714	1.5%	0.7%	1.1%

Crude oil's share of total energy consumption is projected to increase from 38 % in 2000 to 42% in 2050. The natural gas share is projected to grow from 24% to 28% during the same period. Coal generation is projected to decline from a 23% share in 2000 to 20% in 2050. All currently existing nuclear-generation capacity is assumed to retire between 2025 and 2045. However, 14 GW of new nuclear capacity is projected to be added between 2025 and 2040. The share of renewable energy is projected to be relatively stable at between 7% and 8% throughout the projection period.

It should be noted that the outlook for natural gas supply has changed considerably during the past few years. The 2004 Annual Energy Outlook shows considerably tighter gas markets than the 2003 edition. Both U.S. production and net pipeline imports (from Canada and Mexico) show significant declines. While LNG imports for the 2004 AEO are more than twice the level of the 2003 AEO, total gas supply in 2025 is 9.5% lower between the two projections. Overall, the 2025 average natural gas supply price increases by about 11%. A summary of these changes is shown in **Table 4.**

Table 4. Comparison of 2003 and 2004 AEO Natural Gas Supply for 2025

Quad. Btus	AEO 2003	AEO 2004	Difference
U.S. Production	27.6	24.7	-2.8
Net Pipleine Imports	5.7	2.5	-3.2
Net LNG Inports	2.2	4.9	2.7
Total Supply	35.5	32.1	-3.4
Average Supply Price (2001$)	$3.97	$4.42	$0.45

As the MARKAL Baseline Case projection was calibrated to the 2003 Annual Energy Outlook, the natural gas supply assumptions are more optimistic than in the more recent AEO. Nevertheless, LNG imports and Arctic gas supplies account for 44% of gas supply in 2050. **Figure 1** shows natural gas supplies by source for the reference case.

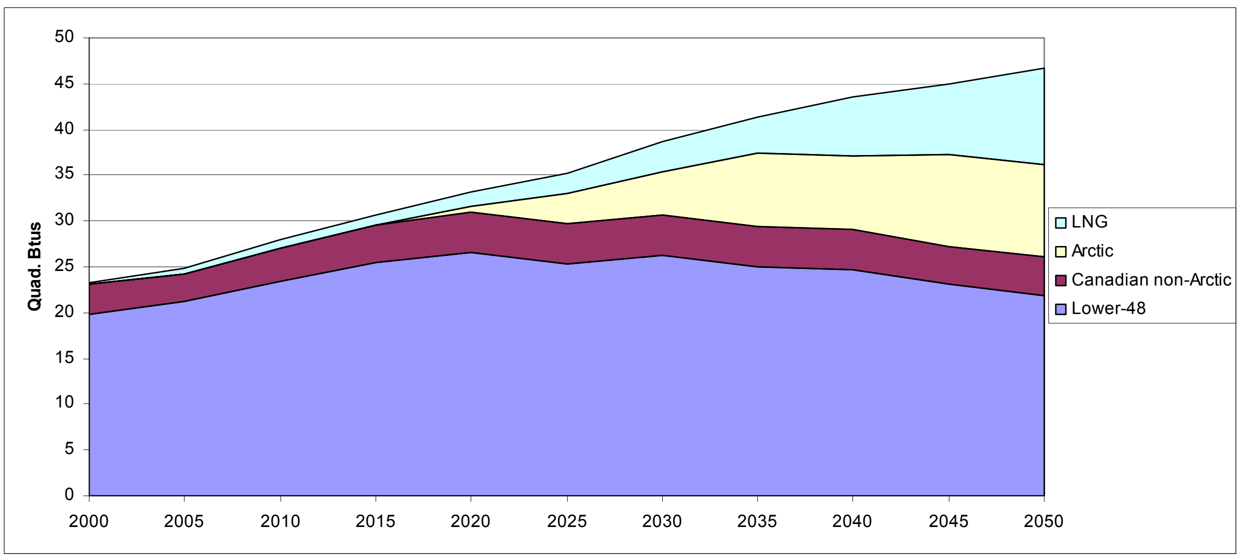
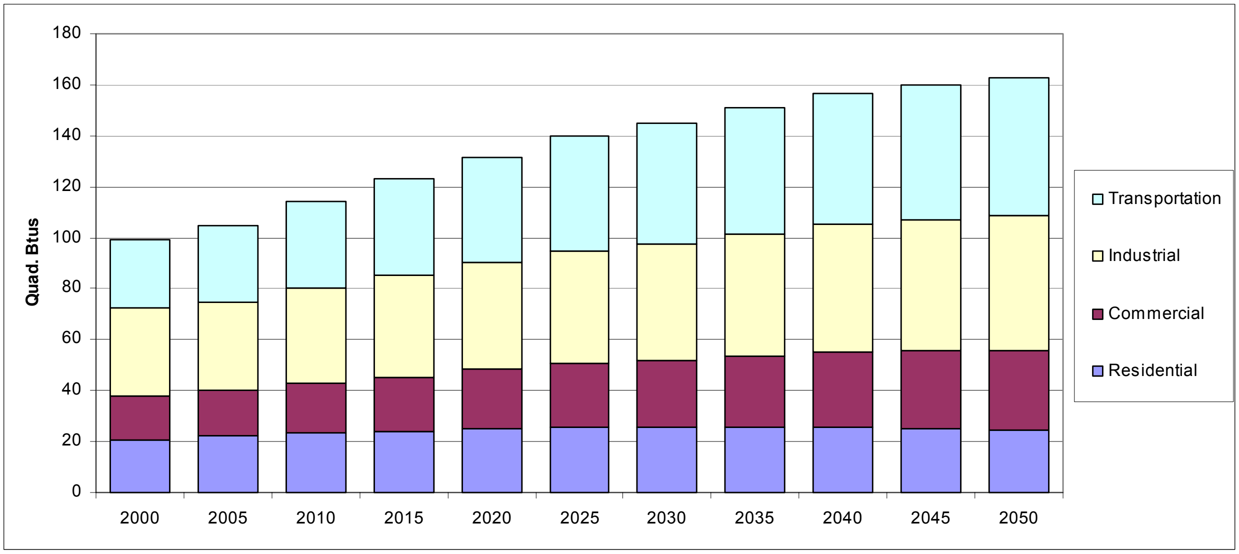


Figure 1. Baseline Case Natural Gas Supply by Source

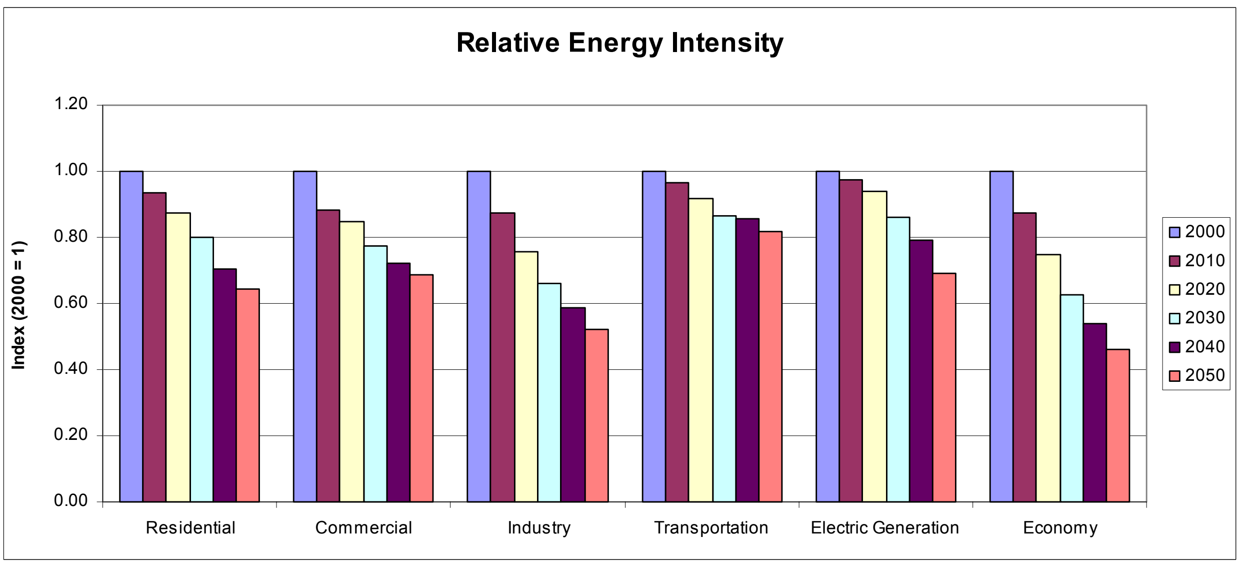
End-Use Energy Demand

The sectoral breakout of energy use, shown in **Figure 2**, demonstrates that transportation energy demand is projected to increase most rapidly, at 1.4% per year, from 2000 to 2050; while residential energy demand increases most slowly, at 0.4% per year. Industrial and commercial energy demands are projected to grow at intermediate rates of 0.9% and 1.2% per year, respectively. The growth rates in energy consumption are a function of the opposing trends of increasing end-use energy service demand and improvements in the efficiency of technologies that satisfy this demand, as well as macroeconomic shifts toward less energy-intensive industries. This phenomenon is best illustrated by examining the energy intensity of the economy. **Figure 3** shows the relative energy intensity for different end-use and conversion sectors, and the economy as a whole.



Note: Consumption totals include electric-generation and distribution losses

Figure 2. Energy Consumption by Sector



Note: Residential index is primary energy, excluding misc. use per household. Commercial index is primary energy use, excluding office equipment and misc. appliances per square foot. Industrial index is total primary energy per unit output. Transportation index is LDV primary energy per mile traveled. Electricity index is nonrenewable average heat rate. Economy index is total primary energy per unit GDP.

Figure 3. Relative Energy Intensity by Sector

As shown in **Figure 3**, the Baseline Case projection indicates that the energy intensity of the economy—which is defined as total primary energy consumption per dollar ($) of GDP—is projected to decrease by more than half by 2050. This decrease reflects both a continued shift toward a service-based economy, as well as increases in energy-technology efficiency. End-use efficiencies are projected to increase throughout the economy over the projection period as new, more-efficient capital stocks are purchased to replace existing equipment and to meet new demand. The Baseline Case technology database includes technologies that are expected to become available in the future, as well as those that are currently on the market. For example, more efficient electric heat pumps and light-duty vehicles are assumed to become available throughout the projection period. The technical and economic data associated with these technologies are derived from a variety of sources, but rely most heavily on the NEMS database.

The residential energy-intensity index shows significant improvements in energy use per household. However, the residential index excludes "miscellaneous demands," the fastest growing segment of residential energy demand. The miscellaneous demand category includes electric devices such as home computers, TVs, and microwave ovens; as well as devices such as gas lamps and swimming pool heaters. Because these service demands are growing faster than the sector as a whole, their energy use per household actually increases over time. Thus, the inclusion of miscellaneous demands in the calculation of residential energy intensity would obscure the efficiency gains being made in other residential service demands.

The commercial energy-intensity index shows significant improvements in energy use per square foot. However, as with the residential sector, this calculation excludes the fastest-growing demand categories: office equipment and miscellaneous commercial appliances. The inclusion of these demand categories would result in relatively constant commercial energy demand per square foot.

The industrial-sector efficiency index shows dramatic declines in energy intensity due to a shift from energy-intensive industries to nonenergy-intensive manufacturing, as well as improvements in process efficiency. During the 50-year projection period, nonenergy-intensive manufacturing output is expected to grow at twice the rate as energy-intensive industrial output. This shift in output exaggerates the decline in energy intensity. However, in the transportation sector, consumer preferences for more powerful engines—and a continued shift from passenger cars to sport utility vehicles (SUVs)—limit gains in overall efficiency.

On an individual technology basis, there are several important trends in the Baseline Case technology assumptions. Although most technologies' capital costs are assumed to remain constant at their current level in real terms, the costs of a few key technologies are projected to decline over time. These include gas combined cycle, integrated coal gasification, and renewable technologies, such as wind and PV. Most of these technologies also show improvements in their heat rates or performance (e.g. capacity factor) between 2000 and 2050.

In the power-generation sector, the efficiency of nonrenewable generation is expected to increase as older, less-efficient fossil steam units retire and new high efficiency gas combined-cycle and IGCC capacity is built. Electric generation by type is shown in **Figure 4**. Natural gas-fired generation is projected to increase its share of total generation from about 18% to 37% during the projection period. Coal-fired generation remains the largest source of electricity at 45% to 51% of total generation. Due to retirements of existing nuclear capacity, nuclear's share of generation falls from 19% to 2% of generation during the projection period. Renewable generation is relatively constant at about 10% of total generation.

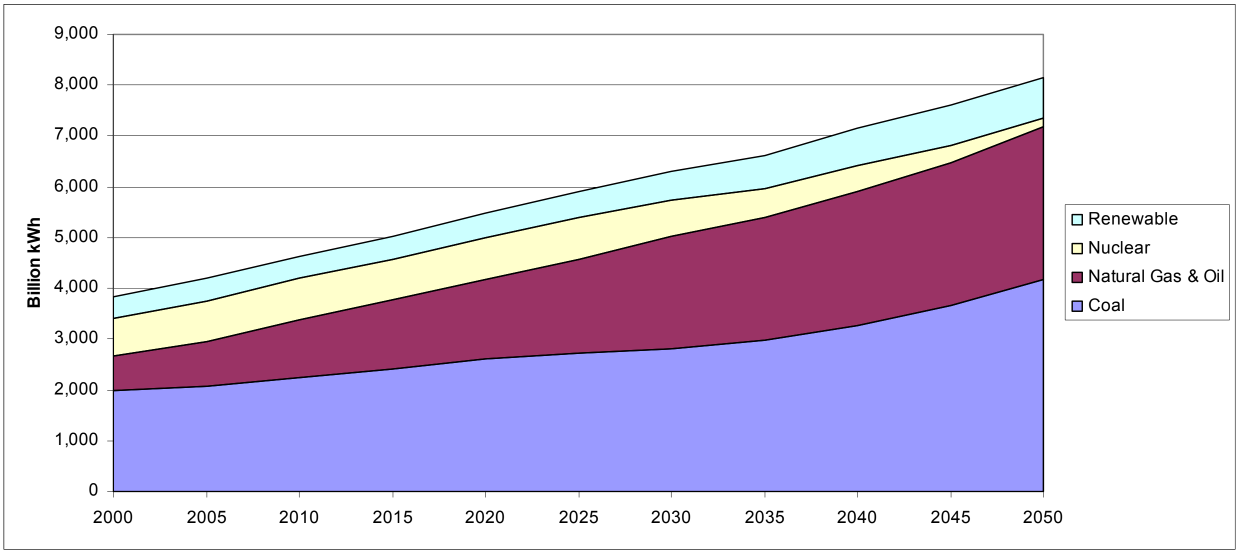


Figure 4. Electricity Generation by Type: Baseline Case

While both natural gas and coal-fired generation show increased efficiency, fossil fuel use for electric generation increases by 92% during the projection period. Such an increase in coal and natural gas demand for power generation is dependent on the availability of these resources. However, potential reduction in supply—such as changes in the outlook in natural gas supply—would necessitate a significant change in fuels used for electric generation.

NEMS Baseline Case Assumptions and Projections

Overview

The Office of Energy Efficiency and Renewable Energy (EERE) programs uses an integrated energy modeling system to analyze the benefits expected from successful implementation of individual programs and the EERE portfolio as a whole. The use of an integrated model provides a consistent economic framework and incorporates the interactive effects among the various programs. Feedback and interactive effects result from (1) changes in energy prices resulting from lower energy consumption, (2) the interaction between supply programs affecting the mix of generation sources and the end-use sector programs affecting the demand for electricity, and (3) additional savings from reduced energy production and delivery.

A modified version of the National Energy Modeling System (NEMS)[1] was one of the models used for this benefits analysis. NEMS is an integrated energy model of the U.S. energy system that was developed by the Energy Information Administration (EIA) for forecasting and policy analysis purposes. The latest version of NEMS available at the time of the benefits analysis—the one used for the *Annual Energy Outlook 2003* (AEO2003)—was used as the starting point. This version provides projection capability to the year 2025. Several changes were made to the model to enhance its ability to represent the EERE programs. The modified version of the model is referred to as NEMS-GPRA05.

GPRA 2005 Baseline

The first step in the benefits analysis process is to establish an appropriate Baseline Case. The EERE Baseline Case is a projection intended to represent the future U.S. energy system without the effect of EERE Programs. This Baseline Case assures that program benefits are estimated based on the same initial forecasts for economic growth, energy prices, and levels of energy demand. It also assures that these initial assumptions are consistent with each other; e.g., that the level of electricity demand expected under the economic growth assumptions could be met at the electricity price assumed. It provides a basis for assessing how well renewable and efficiency technologies might be able to compete against future, rather than current, conventional energy technologies (e.g., more efficient central power generation). Finally, it helps assure that underlying improvements in efficiency and renewable energy are not counted as part of the benefits of the EERE programs.

The most recent Annual Energy Outlook Reference Case is used as the starting point for developing the base case.[2] The Energy Information Administration (EIA) Annual Energy Outlook (AEO) Reference Case provides an independent representation of the likely evolution of energy markets. This forecast reflects expected changes in the demand for energy (e.g., to reflect the availability of new appliances), technology improvements that might improve the efficiency of energy use, and changes in energy resource production costs, including renewable energy.

[1] The National Energy Modeling System: An Overview 2003, March 2003, DOE/EIA-0581(2003)
[2] The Annual Energy Outlook 2003 with Projections to 2025, January 2003, DOE/EIA-0383 (2003). See http://www.eia.doe.gov/oiaf/archive/aeo03/pdf/0383(2003).pdf.

Current energy market policies, such as state Renewable Portfolio Standards, which facilitate the development and adoption of these technologies, are included in the Baseline Case. This approach ensures that EERE's benefits estimates do not include expected impacts of such policies. Neither the EIA Reference Case nor the EERE Baseline Case includes any changes in future energy policies.

The baseline is constructed starting with EIA's *Annual Energy Outlook* Reference Case, and then any identifiable effects of EERE programs already included are removed. For example, EIA's estimate of rooftop photovoltaic installations resulting from the Million Solar Roofs Initiative were removed from the EERE Baseline. The AEO2003 assumption of roughly constant hydroelectric capacity over time was modified to reflect the expectation that without more environmentally benign turbine designs, some reduction in hydro capacity would occur as a result of relicensing requirements. The constraints on the maximum growth rate for cellulosic ethanol production were reduced by a factor of 4, because growth of this new industry is expected to be very slow without EERE program involvement.

The AEO forecast includes technology improvements in all areas of energy demand and supply, and identifying what portion is due to EERE programs is extremely difficult. For GPRA 2005, selected technology changes were made where the AEO appeared to already incorporate the EERE program goals. Technology assumptions that were modified for the baseline include cost and efficiency improvements to distributed combined heat and power (CHP) technologies that were reduced to reflect expected effects without an ongoing DEER program. In addition, the distributed peaker technology in the electricity-generation sector was modified to reflect reciprocating engines (lower capital costs and lower efficiency), and the fixed capacity factor was reduced from 5% to 2.5%.

A few other modifications were made to reflect EERE program assumptions or updated information about energy markets. These changes affect both the Baseline and the Portfolio Cases. The size of typical PV systems was increased to 4 kW in residential and 100 kW in commercial buildings to reflect recent PV installation experience and trends. The maximum market for PV systems was increased from 30% to 55% in the commercial sector and to 60% for residential PVs. Similarly, the maximum market share for gas-fired distributed-generation technologies was increased from 30% to 50% in the commercial sector. California PV credits were incorporated in the Pacific region. Solar water heat was added to the slate of technologies for new homes, and the share of the replacement market in which it can compete was increased from 20% to 50%. The electrodeless fluorescent assumed to become available for commercial lighting in 2015 was removed as recommended by the Building Technologies (BT) Program because they are not aware of a source that shows that much R&D is being directed to develop this level of efficiency. The conversion efficiency of cellulosic ethanol was reduced because EIA's assumption appeared too optimistic.

In a few cases, structural changes were made to improve the model's representation of markets important to EERE technologies. The wind module was modified, so that each of the three wind classes is treated more discretely with separate capital costs and resource multipliers. To improve the geothermal module representation, an EIA update for the price signal sent from the electricity module to the geothermal module was incorporated. The shell indices in the commercial module were replaced with a technology choice algorithm necessary for later representation of EERE shell technologies. In addition, alterations to the distributed-generation algorithm in the building modules were made to smooth new market shares, to reflect the DEER program's market adoption data, to account for the efficiency of using waste heat from combined heat and power systems, and to account for buildings that have already installed a DG technology in prior years.

A summary of these changes is provided in **Table 5**.

Table 5. Summary of Baseline Changes from the AEO2003

	AEO2003	GPRA Baseline Case
Removal of EERE Programs		
Million Solar Roofs	0.4 GW installed 2004 to 2025	Removed
Hydroelectric capacity	Roughly constant hydro capacity and generation	6 % reduction by 2025
Cellulosic ethanol production	0.6 billion gallons by 2025	0.15 billion gallons by 2025
DG technology improvement	Significant improvement	Some improvement but less
Energy Market Updates		
PV system size	2 kW residential, 10 kW commercial	4 kW residential, 100 kW commercial
PV maximum market share	30 % for both residential and commercial	60 % for residential and 55 % for commercial
CHP commercial building maximum share	30 %	50 %
California PV subsidy	Not included	Included for residential systems
Solar water heat	Maximum 30 % replacement market	New and replacement market
Cellulosic conversion efficiency	90 to 103 tons biomass per gallon	82 to 101 tons biomass per gallon
Structural Changes		
Wind module	One capital cost and resource multiplier for all wind classes	Capital costs and resource multipliers by wind classes
Geothermal		Updated price signal
Commercial shell efficiency	Index	Technology representation
Commercial DG algorithms		Market share and stock accounting modified

In the baseline, similar to the AEO2003, oil and natural gas prices are projected to increase from 2005 to 2025, as shown in **Figure 5**. Coal prices, on the other hand, are projected to decline slightly, due to continued productivity gains. Electricity prices are projected to be relatively constant in real terms, with a slight decrease and then an increase after 2010.

The resulting Baseline Case projects a 35% increase in energy demand from 2005 to 2025.[3] Energy efficiency and renewable energy improvements, however, contribute toward a 26% reduction in conventional energy intensity (energy used per dollar of GPD produced) during the

[3] Very similar to the AEO2003.

same period (**Figure 6**).[4] Between 2005 and 2025, renewable energy technology improvements result in increases in electric generation in both central and distributed applications (in billions of kWh) of 27 for geothermal, 28 for biomass, 7 for wind, 4 for municipal solid waste, 19 for photovoltaics, and 0.3 for solar thermal.

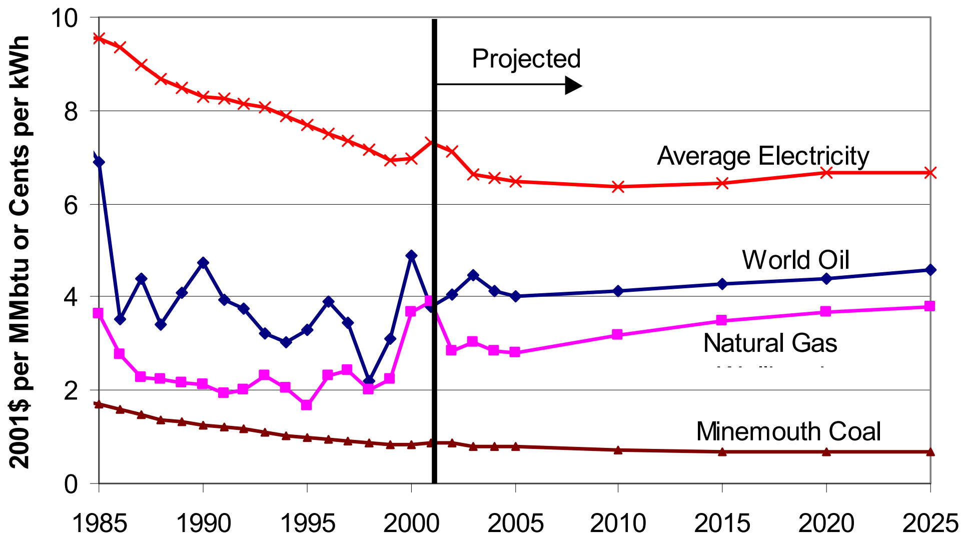


Figure 5. Projected Energy Prices

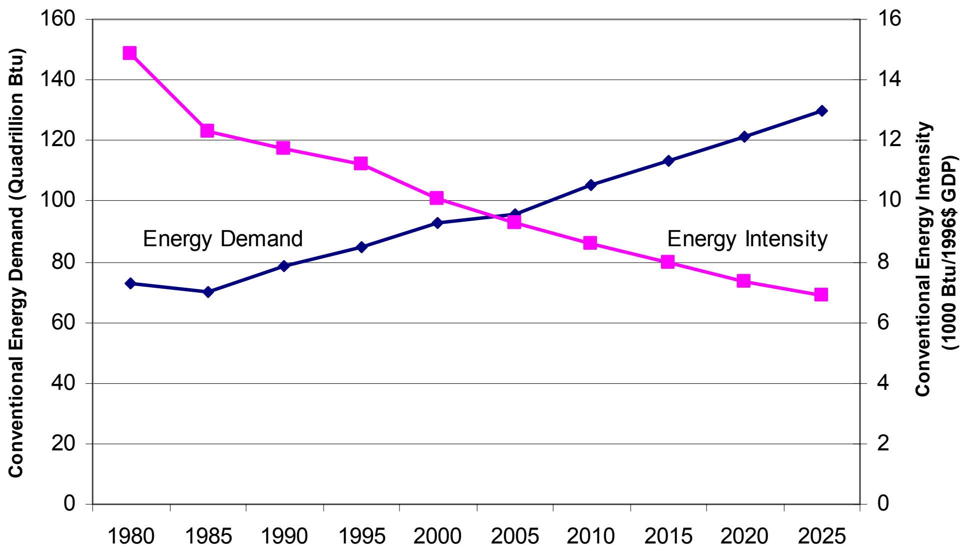


Figure 6. U.S. Conventional Energy Demand and Energy Intensity, 1980-2000, and Baseline Projections to 2025

[4] Energy intensity changes result from a mix of structural changes in the economy (e.g., growing service sector) and efficiency improvements. Two recent EERE-sponsored studies provide additional background on understanding the sources of changes to our energy intensity: Ortiz and Sollinger, *Shaping Our Future by Reducing Energy Intensity in the U.S. Economy; Volume 1: Proceedings of the Conference* (2003, Rand Corporation); and Bernstein, Fonkych, Loeb, and Loughran, "State-Level Changes in Energy Intensity and their National Implications (2003, Rand Corporation).

EERE NEMS-GPRA05 Baseline Case Tables

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

The Worksheet was generated by ftab
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	2005	2010	2015	2020	2025
Production					
Crude Oil & Lease Condensate	11.82	11.92	11.10	11.56	11.26
Natural Gas Plant Liquids	2.95	3.16	3.41	3.58	3.76
Dry Natural Gas	20.68	22.42	24.45	25.70	27.47
Coal	23.32	25.32	26.36	27.49	28.94
Nuclear Power	8.28	8.36	8.41	8.43	8.43
Renewable Energy 1/	6.59	7.15	7.66	8.20	8.67
Other 2/	0.83	0.84	0.74	0.80	0.80
Total	74.46	79.16	82.13	85.76	89.33
Imports					
Crude Oil 3/	22.34	25.09	26.94	27.62	28.52
Petroleum Products 4/	4.21	6.42	9.56	12.02	15.18
Natural Gas	4.54	5.50	5.94	7.28	8.44
Other Imports 5/	0.79	0.90	0.98	0.97	0.94
Total	31.88	37.91	43.42	47.89	53.08
Exports					
Petroleum 6/	2.05	2.24	2.26	2.35	2.40
Natural Gas	0.59	0.61	0.54	0.41	0.37
Coal	1.00	0.91	0.81	0.74	0.67
Total	3.64	3.76	3.60	3.50	3.45
Discrepancy 7/	-0.26	0.20	0.22	0.24	0.18
Consumption					
Petroleum Products 8/	39.75	44.63	48.92	52.65	56.59
Natural Gas	25.24	27.68	30.24	32.97	35.94
Coal	22.80	25.00	26.23	27.48	29.07
Nuclear Power	8.28	8.36	8.41	8.43	8.43
Renewable Energy 1/	6.59	7.15	7.66	8.20	8.67
Other 9/	0.30	0.30	0.27	0.18	0.07
Total	102.97	113.11	121.73	129.92	138.78
Net Imports - Petroleum	24.51	29.27	34.24	37.30	41.29
Prices (2001 dollars per unit)					
World Oil Price ($ per bbl) 10/	23.27	23.99	24.72	25.48	26.57
Gas Wellhead Price($ / Mcf) 11/	2.88	3.28	3.57	3.76	3.89
Coal Minemouth Price ($ / ton)	16.44	14.96	14.64	14.28	14.27
Aver. Electricity (cents / Kwh)	6.49	6.35	6.46	6.67	6.67

1/ Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A18 for selected nonmarketed residential and commercial renewable energy.

2/ Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

3/ Includes imports of crude oil for the Strategic Petroleum Reserve.

4/ Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.

5/ Includes coal, coal coke (net), and electricity (net).

6/ Includes crude oil and petroleum products.

7/ Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

8/ Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

9/ Includes net electricity imports, methanol, and liquid hydrogen.

10/ Average refiner acquisition cost for imported crude oil.

11/ Represents lower 48 onshore and offshore supplies.

Table 2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

	2005	2010	2015	2020	2025
Energy Consumption					
Residential					
Distillate Fuel	0.92	0.89	0.85	0.81	0.78
Kerosene	0.08	0.08	0.07	0.06	0.06
Liquefied Petroleum Gas	0.47	0.46	0.45	0.46	0.46
Petroleum Subtotal	1.48	1.43	1.37	1.33	1.30
Natural Gas	5.46	5.67	5.86	6.11	6.40
Coal	0.01	0.01	0.01	0.01	0.01
Renewable Energy 1/	0.41	0.41	0.41	0.40	0.40
Electricity	4.53	4.93	5.25	5.58	5.91
Delivered Energy	11.89	12.46	12.90	13.44	14.02
Electricity Related Losses	9.72	10.29	10.57	10.99	11.34
Total	21.61	22.75	23.47	24.44	25.37
Commercial					
Distillate Fuel	0.46	0.48	0.48	0.48	0.49
Residual Fuel	0.04	0.04	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.10
Motor Gasoline 2/	0.03	0.03	0.03	0.04	0.04
Petroleum Subtotal	0.65	0.67	0.68	0.68	0.69
Natural Gas	3.61	3.78	3.99	4.30	4.64
Coal	0.09	0.10	0.10	0.11	0.11
Renewable Energy 3/	0.10	0.10	0.10	0.10	0.10
Electricity	4.46	4.97	5.53	6.09	6.65
Delivered Energy	8.91	9.61	10.39	11.27	12.19
Electricity Related Losses	9.56	10.38	11.13	11.99	12.77
Total	18.47	19.99	21.52	23.26	24.96
Industrial 4/					
Distillate Fuel	1.11	1.21	1.29	1.36	1.45
Liquefied Petroleum Gas	2.29	2.55	2.87	3.10	3.33
Petrochemical Feedstocks	1.27	1.43	1.58	1.70	1.82
Residual Fuel	0.17	0.19	0.19	0.20	0.20
Motor Gasoline 2/	0.15	0.17	0.18	0.18	0.20
Other Petroleum 5/	4.15	4.31	4.37	4.50	4.62
Petroleum Subtotal	9.14	9.86	10.47	11.05	11.62
Natural Gas 6/	8.35	9.12	9.76	10.36	11.20
Lease and Plant Fuel 7/	1.32	1.39	1.51	1.58	1.74
Natural Gas Subtotal 6/	9.67	10.51	11.27	11.95	12.93
Metallurgical Coal	0.68	0.66	0.60	0.55	0.50
Steam Coal	1.39	1.44	1.48	1.51	1.53
Net Coal Coke Imports	0.05	0.11	0.15	0.16	0.18
Coal Subtotal	2.13	2.22	2.23	2.22	2.21
Renewable Energy 8/	1.95	2.22	2.51	2.77	3.06
Electricity	3.47	3.95	4.34	4.64	5.02
Delivered Energy	26.35	28.76	30.83	32.63	34.83
Electricity Related Losses	7.43	8.25	8.73	9.14	9.63
Total	33.79	37.00	39.56	41.77	44.46

1/ Includes wood used for residential heating. See Table A18 estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
2/ Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
3/ Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass. See Table A18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
4/ Fuel consumption includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
5/ Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
6/ Includes consumption for combined heat and power; excludes consumption by nonutility generators.
7/ Represents natural gas used in the field gathering and processing plant machinery.
8/ Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes combined heat and power, both for sale to the grid and for own use.

Table 2. Energy Consumption by Sector and Source (Continued)

	2005	2010	2015	2020	2025
Transportation					
Distillate Fuel 9/	5.98	7.08	7.98	8.70	9.58
Jet Fuel 10/	3.41	3.93	4.50	5.09	5.66
Motor Gasoline 2/	17.65	20.09	22.25	24.05	25.91
Residual Fuel	0.82	0.83	0.84	0.85	0.87
Liquefied Petroleum Gas	0.04	0.06	0.07	0.08	0.09
Other Petroleum 11/	0.24	0.26	0.28	0.30	0.32
Petroleum Subtotal	28.15	32.24	35.92	39.08	42.44
Pipeline Fuel Natural Gas	0.66	0.78	0.85	0.91	1.02
Compressed Natural Gas 19/	0.03	0.06	0.08	0.10	0.11
Renewable Energy (E85) 12/	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen 20/	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.11	0.12	0.14
Delivered Energy	28.93	33.17	36.96	40.21	43.72
Electricity Related Losses	0.18	0.19	0.21	0.24	0.27
Total	29.10	33.36	37.18	40.45	43.99
Electric Generators 15/					
Distillate Fuel	0.08	0.11	0.11	0.13	0.17
Residual Fuel	0.26	0.32	0.37	0.39	0.38
Petroleum Subtotal	0.34	0.42	0.48	0.52	0.56
Natural Gas	5.81	6.89	8.19	9.60	10.84
Steam Coal	20.57	22.67	23.88	25.15	26.73
Nuclear Power	8.28	8.36	8.41	8.43	8.43
Renewable Energy/Other 16/	4.13	4.43	4.65	4.92	5.11
Electricity Imports 17/	0.30	0.30	0.27	0.18	0.07
Total	39.43	43.06	45.87	48.80	51.74
Total Energy Consumption					
Distillate Fuel	8.56	9.78	10.70	11.49	12.47
Kerosene	0.12	0.12	0.12	0.11	0.10
Jet Fuel 10/	3.41	3.93	4.50	5.09	5.66
Liquefied Petroleum Gas	2.90	3.15	3.49	3.73	3.98
Motor Gasoline 2/	17.84	20.29	22.46	24.27	26.14
Petrochemical Feedstocks	1.27	1.43	1.58	1.70	1.82
Residual Fuel	1.29	1.38	1.45	1.49	1.50
Other Petroleum 13/	4.37	4.55	4.63	4.78	4.92
Petroleum Subtotal	39.75	44.63	48.92	52.65	56.59
Natural Gas	23.26	25.52	27.89	30.48	33.18
Lease and Plant Fuel 7/	1.32	1.39	1.51	1.58	1.74
Pipeline Natural Gas	0.66	0.78	0.85	0.91	1.02
Natural Gas Subtotal	25.24	27.68	30.24	32.97	35.94
Metallurgical Coal	0.68	0.66	0.60	0.55	0.50
Steam Coal	22.07	24.22	25.47	26.77	28.38
Net Coal Coke Imports	0.05	0.11	0.15	0.16	0.18
Coal Subtotal	22.80	25.00	26.23	27.48	29.07
Nuclear Power	8.28	8.36	8.41	8.43	8.43
Renewable Energy 18/	6.59	7.15	7.66	8.20	8.67
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity Imports 17/	0.30	0.30	0.27	0.18	0.07
Total	102.97	113.11	121.73	129.92	138.78

2/ Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
7/ Represents natural gas used in the field gathering and processing plant machinery.
9/ Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
10/ Includes only kerosene type.
11/ Includes aviation gas and lubricants.
12/ E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
13/ Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
15/ Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sellelectricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
16/ Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
17/ In 1999 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
18/ Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
19/ Includes natural gas for hydrogen production.
20/ Hydrogen is not reported separately but rather as the fuel feedstock. See note 19.

Table 3. Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

	2005	2010	2015	2020	2025
Residential	13.75	13.86	14.29	14.65	14.84
Primary Energy 1/	7.81	7.94	8.17	8.30	8.46
Petroleum Products 2/	9.72	9.88	10.30	10.68	10.99
Distillate Fuel	7.89	7.96	8.35	8.71	8.93
Liquefied Petroleum Gas	13.65	14.00	14.30	14.52	14.83
Natural Gas	7.31	7.47	7.69	7.80	7.96
Electricity	22.88	22.40	22.73	23.13	23.15
Commercial	13.07	13.25	13.84	14.50	14.65
Primary Energy 1/	6.00	6.34	6.61	6.79	6.98
Petroleum Products 2/	6.67	6.79	7.14	7.51	7.78
Distillate Fuel	5.58	5.66	6.08	6.49	6.75
Residual Fuel	3.91	4.01	4.12	4.23	4.38
Natural Gas 3/	5.99	6.38	6.65	6.80	6.99
Electricity	19.96	19.56	20.07	20.95	20.92
Industrial 4/	5.97	6.27	6.66	6.94	7.16
Primary Energy	4.77	5.07	5.45	5.65	5.87
Petroleum Products 2/	6.65	6.94	7.42	7.65	7.94
Distillate Fuel	5.62	5.73	6.28	6.82	7.24
Liquefied Petroleum Gas	9.28	9.58	9.90	10.13	10.40
Residual Fuel	3.60	3.71	3.82	3.94	4.10
Natural Gas 5/	3.52	3.88	4.20	4.37	4.56
Metallurgical Coal	1.58	1.51	1.46	1.40	1.35
Steam Coal	1.44	1.38	1.35	1.31	1.29
Electricity	12.78	12.69	12.88	13.48	13.57
Transportation	9.95	10.28	10.18	10.42	10.82
Primary Energy	9.93	10.26	10.15	10.40	10.79
Petroleum Products 2/	9.93	10.26	10.15	10.40	10.80
Distillate Fuel 6/	9.37	10.22	10.04	10.26	10.54
Jet Fuel 7/	5.62	5.62	5.97	6.38	6.72
Motor Gasoline 8/	11.33	11.53	11.34	11.61	12.08
Residual Fuel	3.45	3.55	3.66	3.77	3.94
Liquefied Petroleum Gas9/	14.84	15.19	15.45	15.53	15.61
Natural Gas 10/	6.09	7.05	7.55	7.79	8.02
Ethanol (E85) 11/	19.51	21.32	22.94	22.88	23.43
Electricity	19.81	19.08	18.87	18.62	17.95

1/ Weighted average price includes fuels below as well as coal.
2/ This quantity is the weighted average for all petroleum products, not just those listed below.
3/ Excludes independent power producers.
4/ Includes combined heat and power.
5/ Excludes uses for lease and plant fuel.
6/ Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
7/ Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
8/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
9/ Includes Federal and State taxes while excluding county and local taxes.
10/ Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
11/ E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

Table 3. Energy Prices by Sector and Source (Continued)

	2005	2010	2015	2020	2025
Average End-Use Energy	9.67	9.91	10.12	10.46	10.74
Primary Energy	7.68	8.05	8.21	8.47	8.79
Electricity	19.03	18.61	18.93	19.56	19.56
Electric Generators 12/					
Fossil Fuel Average	1.70	1.81	1.95	2.05	2.15
Petroleum Products	4.13	4.26	4.40	4.64	4.93
Distillate Fuel	5.03	5.12	5.59	5.99	6.17
Residual Fuel	3.86	3.96	4.06	4.19	4.38
Natural Gas	3.27	3.78	4.16	4.36	4.58
Steam Coal	1.22	1.17	1.15	1.12	1.10
Average Price to All Users 13/					
Petroleum Products 2/	9.15	9.48	9.54	9.81	10.18
Distillate Fuel	8.48	9.17	9.23	9.54	9.85
Jet Fuel	5.62	5.62	5.97	6.38	6.72
Liquefied Petroleum Gas	10.15	10.40	10.66	10.85	11.09
Motor Gasoline 8/	11.32	11.53	11.34	11.61	12.08
Residual Fuel	3.57	3.68	3.80	3.92	4.09
Natural Gas	4.73	5.03	5.28	5.41	5.57
Coal	1.24	1.18	1.16	1.13	1.12
Ethanol (E85) 11/	19.51	21.32	22.94	22.88	23.43
Electricity	19.03	18.61	18.93	19.56	19.56
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)					
Residential	157.97	167.02	178.54	191.05	202.08
Commercial	115.11	126.06	142.42	162.02	177.13
Industrial	118.70	135.36	154.28	171.02	188.98
Transportation	281.32	333.00	367.43	409.71	461.82
Total Non-Renewable Expenditures	673.10	761.44	842.67	933.79	1030.01
Transportation Renewable Expenditures	0.03	0.05	0.07	0.09	0.11
Total Expenditures	673.13	761.49	842.73	933.88	1030.12

11/ E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
12/ Includes all electric power generators except combined heat and power, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
13/ Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Table 4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

	2005	2010	2015	2020	2025
Generation by Fuel Type					
Electric Power Sector 1/					
Power Only 2/					
Coal	1988	2191	2325	2471	2659
Petroleum	31	39	44	48	54
Natural Gas 3/	511	702	938	1139	1333
Nuclear Power	793	800	805	807	807
Pumped Storage/Other	-1	-1	-1	-1	-1
Renewable Sources 4/	367	379	388	398	406
Distributed Gen (Natural Gas)	0	2	4	7	12
Non-Utility Gen for Own Use	-24	-24	-24	-24	-24
Total	3666	4089	4479	4847	5248
Combined Heat and Power 5/					
Coal	30	33	33	33	33
Petroleum	3	4	4	4	4
Natural Gas	176	167	151	156	153
Renewable Sources	4	4	4	4	4
Non-Utility Gen for Own Use	-18	-18	-18	-18	-18
Total	196	190	174	179	176
Net Available to the Grid	3861	4279	4654	5026	5424
End-Use Sector Generation 6/					
Combined Heat and Power					
Coal	23	23	23	23	23
Petroleum	6	6	6	6	6
Natural Gas	98	114	130	159	201
Other Gaseous Fuels 7/	7	7	7	7	8
Renewable Sources 4/	34	39	45	50	56
Other 8/	11	11	11	11	11
Total	180	201	222	257	305
Other End-Use Generators 9/	6	6	6	9	23
Generation for Own Use	-148	-160	-173	-200	-248
Total Sales to the Grid	37	47	55	66	80
Net Imports	29	29	26	17	7

1/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
5/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
7/ Other gaseous fuels include refinery and still gas.
8/ Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
9/ Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

Table 4. Electricity Supply, Disposition, Prices, and Emissions (Continued)

	2005	2010	2015	2020	2025
Electricity Sales by Sector					
Residential	1328	1445	1539	1636	1732
Commercial	1307	1458	1620	1784	1950
Industrial	1016	1158	1272	1361	1470
Transportation	24	27	31	36	42
Total	3676	4089	4461	4817	5194
End-Use Prices 10/ (2001 cents per kilowatthou					
Residential	7.8	7.6	7.8	7.9	7.9
Commercial	6.8	6.7	6.8	7.1	7.1
Industrial	4.4	4.3	4.4	4.6	4.6
Transportation	6.8	6.5	6.4	6.4	6.1
All Sectors Average	6.5	6.4	6.5	6.7	6.7
Prices by Service Category 10/ (2001 cents per kilowatthour)					
Generation	3.9	3.8	4.0	4.2	4.2
Transmission	0.6	0.6	0.6	0.6	0.6
Distribution	2.0	2.0	1.9	1.9	1.9
Emissions					
Sulfur Dioxide (million tons)	10.67	9.55	8.95	8.95	8.95
Nitrogen Oxide (million tons)	3.60	3.93	4.00	4.07	4.13
Mercury (tons)	49.31	51.22	51.19	51.85	52.61

10/ Prices represent average revenue per kilowatthour.

Table 5. Electricity Generating Capacity
(Gigawatts)

	2005	2010	2015	2020	2025
Electric Power Sector 2/					
Power Only 3/					
Coal Steam	303.1	306.6	321.1	339.2	364.1
Other Fossil Steam 4/	118.3	81.5	76.8	75.2	74.3
Combined Cycle	103.3	143.1	194.3	221.3	260.8
Combustion Turbine/Diesel	126.0	120.5	125.3	129.8	131.8
Nuclear Power 5/	100.2	99.3	99.5	99.6	99.6
Pumped Storage	19.6	19.4	19.2	19.2	19.1
Fuel Cells	0.0	0.1	0.2	0.2	0.2
Renewable Sources 6/	92.2	93.3	94.7	96.1	97.3
Distributed Gen (Nat Gas) 7/	1.8	8.6	18.6	32.9	55.6
Total	864.5	872.4	949.7	1013.5	1102.7
Combined Heat and Power 8/					
Coal Steam	5.2	5.1	5.1	5.1	5.1
Other Fossil Steam	1.2	1.2	1.2	1.2	1.2
Combined Cycle	31.2	31.0	31.0	31.0	31.0
Combustion Turbine/Diesel	5.2	5.2	5.2	5.2	5.2
Renewable Sources	0.2	0.2	0.2	0.2	0.2
Total	43.0	42.8	42.8	42.8	42.8
Total Electric Power Industry	907.5	915.2	992.5	1056.3	1145.5
Cumulative Planned Additions 9/					
Coal Steam	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0
Combined Cycle	63.1	63.1	63.1	63.1	63.1
Combustion Turbine/Diesel	27.8	27.8	27.8	27.8	27.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.2	0.2	0.2
Renewable Sources	3.8	4.9	5.8	6.4	6.5
Distributed Generation	0.0	0.0	0.0	0.0	0.0
Total	95.0	96.2	97.2	97.8	98.0
Cumulative Unplanned Additions 9/					
Coal Steam	0.0	7.1	22.1	41.5	67.4
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0
Combined Cycle	4.0	44.1	95.3	122.3	161.8
Combustion Turbine/Diesel	3.7	6.5	12.4	19.1	24.3
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.3	1.2	2.1	3.2	4.4
Distributed Generation	1.8	8.6	18.6	32.9	55.6
Total	9.7	67.5	150.5	219.1	313.5
Cumulative Total Additions	104.7	163.7	247.7	316.9	411.4
Cumulative Retirements 10/					
Coal Steam	2.1	5.8	6.3	7.6	8.7
Other Fossil Steam	14.0	50.8	55.5	57.1	58.0
Combined Cycle	0.0	0.5	0.5	0.5	0.5
Combustion Turbine/Diesel	3.0	11.3	12.4	14.7	17.8
Nuclear Power	0.0	1.8	2.8	2.8	2.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.1	0.1	0.1	0.1	0.1
Total	19.2	70.4	77.7	82.8	88.0

1/ Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

2/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

3/ Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

4/ Includes oil-, gas-, and dual-fired capacity.

5/ Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

6/ Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.

7/ Primarily peak-load capacity fueled by natural gas.

8/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public

Table 5. Electricity Generating Capacity (Continued)

	2005	2010	2015	2020	2025
End-Use Sector Generators 11/					
Combined Heat and Power					
Coal	4.8	4.8	4.8	4.8	4.8
Petroleum	1.0	1.0	1.0	1.0	1.0
Natural Gas	16.0	18.2	20.3	24.3	30.1
Other Gaseous Fuels	2.2	2.2	2.2	2.2	2.3
Renewable Sources	5.2	6.2	7.2	8.0	9.0
Other	0.7	0.7	0.7	0.7	0.7
Total	29.9	33.0	36.1	41.0	47.9
Other End-Use Generators 12/	0.0	0.0	0.0	0.0	0.0
Renewable Sources	1.7	1.7	1.7	3.2	10.1
Cumulative Additions 9/					
Combined Heat and Power	2.3	5.4	8.5	13.4	20.3
Other End-Use Generators	0.5	0.5	0.5	1.9	8.9

9/ Cumulative additions after December 31, 1999.
11/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
12/ Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

Table 6. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent, Unless Otherwise Noted)

	2005	2010	2015	2020	2025
Residential					
Petroleum	27.9	27.0	25.9	25.0	24.4
Natural Gas	78.7	81.7	84.4	88.0	92.1
Coal	0.4	0.4	0.4	0.4	0.3
Electricity	222.8	243.4	255.0	269.6	284.4
Total	329.8	352.5	365.7	383.0	401.3
Commercial					
Petroleum	12.6	13.0	13.2	13.3	13.4
Natural Gas	52.0	54.4	57.4	61.9	66.8
Coal	2.3	2.5	2.6	2.7	2.8
Electricity	219.3	245.5	268.5	293.9	320.2
Total	286.2	315.4	341.6	371.8	403.2
Industrial 1/					
Petroleum	93.3	98.7	102.4	106.9	110.8
Natural Gas 2/	136.9	148.8	159.5	169.1	183.0
Coal	53.9	56.2	56.6	56.2	56.2
Electricity	170.5	195.0	210.8	224.1	241.3
Total	454.6	498.7	529.3	556.3	591.4
Transportation					
Petroleum 3/	538.1	616.4	686.8	747.2	811.5
Natural Gas 4/	10.0	12.0	13.4	14.5	16.3
Other 5/	0.0	0.0	0.0	0.0	0.0
Electricity	4.0	4.6	5.2	5.9	6.8
Total 3/	552.2	633.1	705.4	767.6	834.6
Total by Delivered Fuel					
Petroleum 3/	671.9	755.2	828.3	892.4	960.1
Natural Gas	277.6	296.9	314.8	333.5	358.2
Coal	56.6	59.0	59.6	59.3	59.3
Other 5/	0.0	0.0	0.0	0.0	0.0
Electricity	616.6	688.5	739.4	793.6	852.8
Total 3/	1622.7	1799.6	1942.0	2078.7	2230.4
Electric Power Sector 6/					
Petroleum	7.1	8.9	10.0	10.8	11.5
Natural Gas	83.6	99.3	117.9	138.3	156.1
Coal	525.9	580.4	611.5	644.5	685.2
Total	616.6	688.5	739.4	793.6	852.8
Total by Primary Fuel 7/					
Petroleum 3/	679.0	764.0	838.2	903.2	971.7
Natural Gas	361.2	396.1	432.7	471.8	514.3
Coal	582.5	639.4	671.0	703.8	744.5
Other 5/	0.0	0.0	0.0	0.0	0.0
Total 3/	1622.7	1799.6	1942.0	2078.7	2230.4

1/ Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Includes lease and plant fuel.
3/ This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
4/ Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
5/ Includes methanol.
6/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
7/ Emissions from the electric power sector are distributed to the primary fuels.

Appendix B – GPRA05 Biomass Program Documentation

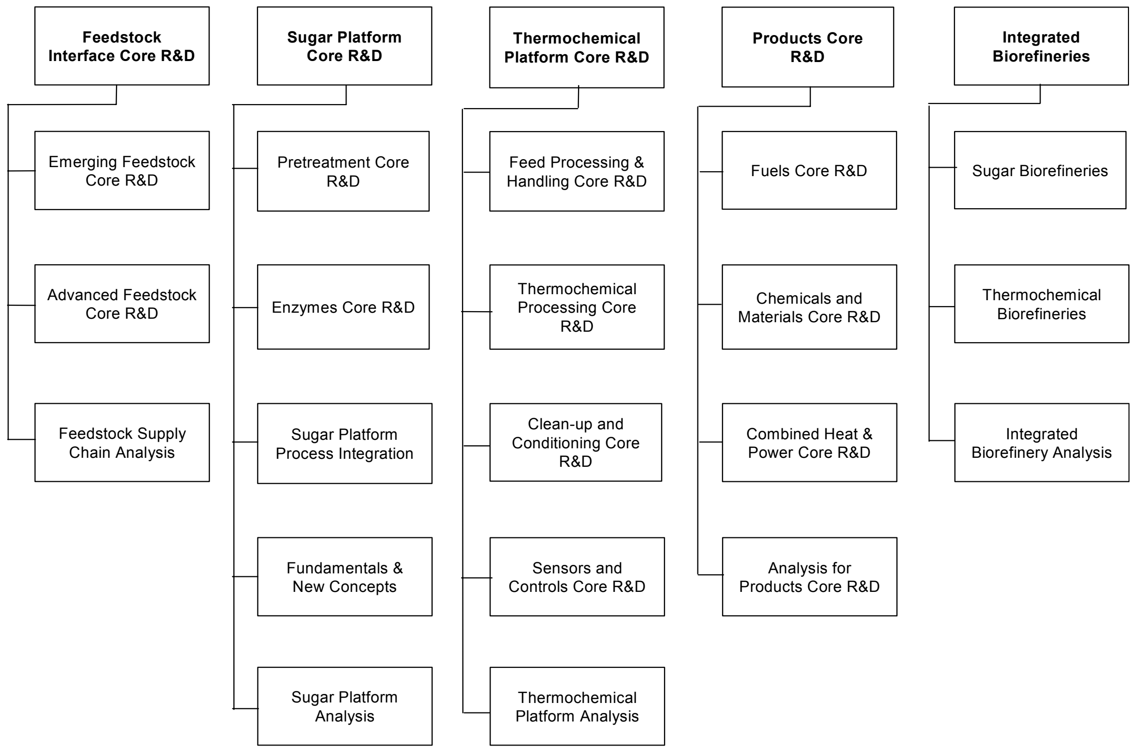

Figure 1. The Biomass Program Hierarchy

Introduction

This report discusses the assumptions and methods employed in the analysis that provided inputs to the process of estimating the benefits of EERE's Biomass Program. There were two separate analyses conducted for the Biomass Program, one for bioproducts and one for biofuels.

The major focus of the Biomass Program is to establish the economic viability of biorefineries producing fuels and high-value bio-based products, i.e., chemicals and/or materials from biomass feedstock, along with heat and power for internal biorefinery use. The biorefinery configuration may vary as a function of site-specific conditions, including feedstock availability and price, local market demand, and other factors. This analysis is based on two types of biorefineries: biorefineries producing primarily fuel ethanol and high-value chemical coproducts; and biorefineries producing chemicals and materials other than fuels. Technical research data that can support analyses of integrated, multiproducts biorefineries are being developed by the government and industry. Consequently, the market penetration estimate for bio-based products from nonfuel biorefineries was calculated separately from biorefineries producing primarily ethanol. As additional research is completed, new fuels and coproducts and other biorefinery concepts may be added to the biorefinery analysis. Both the bioproducts and the biofuels analyses focus on benefits of future achievements by the EERE biomass program and specifically exclude any future or past benefits resulting from historical technology improvements.

As bio-based products increasingly penetrate markets, they will displace petroleum feedstocks traditionally used in the production of such products. However, more important, as bio-based products are produced in biorefineries, they will serve as enabling agents that reduce the costs of the coproduced energy products. This will occur through production synergies and the allocation of capital and operating costs across a broad array of energy and nonenergy biorefinery products. The bio-based products analysis was based on generic bio-based products.

The biofuels analysis was limited to ethanol, because it is the current focus of the biofuels element of the biomass program. Other biofuels may be included in the future when more data are available.

The biofuels analysis is based on a sugar-based biorefinery configuration that will produce primarily ethanol, along with side-streams (in smaller quantities) of high-value, generic bio-based products. The biofuels analysis did not estimate the benefits from the coproduction of bio-based products, other than what is inherent in their role of increasing ethanol market penetration through the synergistic affects (as discussed above) of biorefinery credits. The credit for bio-based coproducts is based on 1 cent per gallon of ethanol produced in 2020 and gradually increasing to 14 cents per gallon by 2050, as biorefinery technology matures. Additional biorefinery configurations will be defined and analyzed as new data and analytic tools become available.

For the biofuels analysis, the Ethanol Long Range Systems Analysis Spreadsheet (ELSAS) was used to integrate ethanol supply and demand data to determine market penetration. The ELSAS results were then used as input to the NEMS-GPRA05 and MARKAL-GPRA05 models to determine benefits.

Section 2 presents the documentation of the analysis for bio-based products. **Section 3** presents the documentation of the analysis for biofuels.

Bio-based products

In prior years, energy and environmental benefits analyses were performed for each industrial bio-based product (chemicals and materials) R&D project using a Microsoft Excel spreadsheet originally developed by Energetics, Inc., and later modified by Arthur D. Little and other consultants for the Industrial Technologies Program. The metrics were projected approximately 20 years into the future using an experience-based market-penetration model. Variables such as commercialization years, target-market sizes, and market-penetration rates were estimated using input from the principle investigator, industry experts, and the project manager.

At this time, data are insufficient to support a truly integrated biorefinery approach to the analysis. Instead, the industrial bio-based products analysis methodology for the GPRA FY 2004 analysis was modified for GPRA FY 2005 to focus on the energy savings from "generic" industrial bio-based products and to be more closely aligned with the industrial bio-based products goal: "through 2010, establish the technical and market potential of at least three new commodity-scale chemicals and/or materials." This goal is from the FY 2005 budget request submitted to the Interior and Related Agencies Subcommittee.

Because the Biomass Program has not identified specific targeted bio-based products at this point, the benefits analysis is based on generic products. The energy-use profile from the FY 2004 GPRA estimates for 2005 was averaged to estimate the energy-use profile for the average generic industrial bio-based product. The profile, which included a wide range of bio-based products (polymers, solvents, and other chemicals and materials), was averaged by summing the energy savings from the GPRA FY 2004 bio-based products analyses and dividing the total by the volume of products it represented. This resulted in a profile of approximately 20,000 Btu of fossil energy displaced per pound of generic bio-based product, with the displaced energy distributed between feedstock and processing requirements. It should be noted that the energy-use profile below does not consider the use of biomass materials for on-site energy generation through co-firing or other methods. Bio-based products may consume more electricity than conventional chemicals and materials. Starch/lignocellulosic-based products will involve handling dilute aqueous streams from the pretreatment step and through the final processing step, requiring considerable electricity for processes such as separation and purification (negative electricity saving in the table of energy savings below).

Near-term (2005-2010) energy and environmental benefits were estimated, based on the progress of current Biomass Program-funded industrial bio-based product R&D toward commercialization in a biorefinery. From 2010 to 2015, the market for industrial bio-based products developed with Biomass Program support was projected to grow 4% annually as those bio-based products that are commercialized in the next few years increase their market share and additional biorefineries are constructed.

As the market share and consumer awareness and acceptance of industrial bio-based products increases, it is projected that the subsequent commercialization of new products and market growth of established bio-based products will proceed at a slightly faster rate. Beyond 2015, the annual growth was increased to 6% to reflect the accelerated commercialization/market growth of industrial bio-based products produced in integrated biorefineries. **Table 1** presents energy-related inputs to the NEMS-GPRA05 model related to bio-based products. The final table in this section provides estimates of the current production of bio-based products compared to the sizes of the markets in which these products compete.

Table 1. FY05 Bio-based Products NEMS-GPRA05 Inputs
Energy Savings due to Bio-based Products Market Penetration

		2005	2010	2015	2020	2025
Natural Gas	T Btu	3.37	7.49	9.12	12.20	16.33
Coal	T Btu	0.22	-0.82	-1.00	-1.34	-1.80
Electricity[1]	B kWh	-0.38	-0.66	-0.80	-1.07	-1.44
Distillate	T Btu	2.80	7.88	9.59	12.84	17.18
Oil Feedstock	T Btu	7.67	18.27	22.22	29.74	39.80
Total	**T Btu**	**10.04**	**26.87**	**33.29**	**44.96**	**60.16**
Annual Growth from previous period				4%	6%	6%

Current (1999-2001 depending on data source) Market Size

Lubricants and greases[1]	19.6 Billion lbs
Organic chemical (including polymers)[2]	175.2 Billion lbs
Polymers[3]	100.1 Billion lbs
U.S. Bio-based products[4]	12.4 – 21.1 Billion lbs (depending on study)

Biofuels (Ethanol)

Target Markets

Market Description

In 2003, U.S. fuel ethanol production reached 2.8 billion gallons, an increase of 32% from the previous year.[5]

EERE targets ethanol technology for the gasoline additive market in the midterm and as a gasoline substitute in the longer term. In 2002, approximately 99% of the ethanol consumed in the United States was for the gasoline additive market and 1% was for gasoline substitute.[6] In 2004, the majority of the ethanol consumed in the additive market is used as an oxygenate component (additive) for gasoline, and the remainder is used as a gasoline additive to improve octane in conventional gasoline. Within the oxygenate market, in early 2004, methyl-tertiary-butyl-ether (MTBE) and ethanol each provided approximately 50% of the volume. However, ethanol is expected to take a much larger share of this market as MTBE is phased out in many states due to environmental concerns (see discussion of MTBE later in this section for additional detail). As recently as 2002, MTBE accounted for approximately 70% of the oxygenate market.[7] In 2002, MTBE accounted for approximately 2.39% and ethanol 1.16% of the U.S. on-highway motor fuel (gasoline plus diesel).

The Clean Air Act requires a minimum level of oxygen content in both reformulated gasoline (RFG) and oxygenated gasoline. RFG, which is required in ozone nonattainment areas, and oxygenated gasoline, which is required in carbon monoxide (CO) nonattainment areas, are not the same. Ethanol competes with MTBE in both of these oxygenate market segments. Most of

[1] Negative electricity savings represent greater electricity consumption in converting biomass feedstocks to products compared to converting petroleum feedstocks to similar products.

the MTBE (and an increasing share of ethanol) are used in RFG, which is the most important market segment for oxygenates. Both ethanol and MTBE are used in the smaller oxygenated gasoline market segment, with ethanol being the dominant oxygenate. In a third market segment, ethanol is blended with conventional gasoline to make gasohol, which is primarily marketed in the Midwest. Gasohol consists of 90% gasoline and 10% ethanol by volume, with the ethanol serving as an octane enhancer and gasoline extender.

After adjusting for its Federal excise tax exemption, the price of ethanol has historically tracked with the price of gasoline, whereas MTBE is normally priced at a premium relative to gasoline. However, MTBE used to be the oxygenate of choice in RFG for most refiners outside the Midwest because of its wider availability, more favorable blending characteristics for summer Reid Vapor Pressure, and ease of distribution. When blended into gasoline, ethanol raises the vapor pressure of the mixture, while adding MTBE to gasoline has only a minor effect on vapor pressure. Because ethanol absorbs water, which is typically present in small quantities in the U.S. petroleum products pipeline system, ethanol and ethanol blends are not routinely shipped via pipeline. Consequently, ethanol is shipped by rail, truck, and/or barges to distribution terminals where it is blended into gasoline. MTBE is blended into gasoline at the refinery, and MTBE blends do not require any special handling compared with gasoline that has no MTBE.

MTBE is currently the subject of environmental concern in several communities, due to its leakage and contamination of groundwater. It imparts a turpentine odor to water at low concentrations. There have been several efforts at the national level to completely phase out MTBE's use in gasoline. At this time, these efforts have not succeeded. Eighteen states, however, have issued their own limits on MTBE use. The states that have enacted MTBE bans account for more than 60% of the MTBE consumption.

The 2003 production level for ethanol was more than 2.8 billion gallons per year. The consumption of MTBE in 2002 was approximately 4 billion gallons, but MTBE consumption will decline as California, New York, Connecticut and other states transition from MTBE to ethanol. A national ban on MTBE would increase the demand for ethanol because ethanol, like MTBE, is a high-octane content, virtually sulfur-free additive that reduces toxic air emissions. Ethanol also will help solve the problem of fuel volume loss that would accompany an MTBE ban because oxygenates such as MTBE (or ethanol or other oxygenates), when blended in gasoline, also are used by the automobile engine as a fuel. Reformulated gasoline typically contains 11% MTBE.

To promote a stronger role for ethanol and other biofuels in the U.S. fuels market, Congress has debated a Renewable Fuels Standard (RFS), which would require that gasoline sold or dispensed to consumers in the United States contain a certain volume of renewable fuel. The proposed requirement for renewable fuel volume would ramp up to 5.0 billion gallons per year within approximately 10 years. Thereafter, the RFS volume would increase proportionately to the increase in total motor fuel consumption. This program has provisions for a credit-trading system that would give refiners flexibility for implementing the RFS in the marketplace. Other biofuels besides ethanol, such as biodiesel (a biologically derived fuel from soybeans, rapeseed, or used cooking oil) for blending with diesel fuel can be used to satisfy the RFS requirement. The proposed legislation also called for repealing the RFG oxygen requirement. Congress is still debating the RFS requirement, but many analysts believe it will be enacted during FY 2004.

Vehicle fleets include alternative-fuel vehicles that have been either modified or manufactured to accommodate the use of E85 (85% ethanol and 15% gasoline) or E95 (95% ethanol and 5% gasoline). Many of these vehicles are flexible-fuel vehicles enabling their use with gasoline or E85. The vehicle fleet market is dominated by government agencies, but also includes fleets owned by corporate entities and other organizations (taxi cabs, utilities, airport authorities, etc.). The use of green fuels in Federal Government fleets is driven largely by the alternative-fuel vehicle requirements under the Energy Policy Act of 1992. The market penetration of E85 has been much lower than for E10 because (1) only a limited number or vehicles can use E85, (2) it is generally more costly than gasoline on a BTU basis, and (3) the required investment for refueling infrastructure is greater for E85 and E95 than for E10. In the longer term, once production technology improvements achieve parity between the value of ethanol and gasoline, ethanol will compete directly with gasoline in broader automotive fuel markets. In this instance, the growth of ethanol consumption eventually will become limited by the availability of biomass feedstocks rather than by ethanol market demand.

Baseline Technology Improvements

In its AEO2003 Reference Case, the Energy Information Administration (EIA) assumed a growth scenario for cellulosic ethanol. EERE analysis uses EIA's reference case as the basis for calculating its baseline—a scenario in which there is no EERE R&D. After evaluating the technical and market barriers to the development of ethanol biorefineries using cellulosic feedstock, EERE concluded that without Federal investment in RD&D, the cellulosic ethanol industry would grow at only 25% (at best) of the rate postulated in the EIA Reference Case. The rationale for this assumption is industry's reticence to underwrite cellulosic ethanol research because of its risk and cost. For example, for a decade, the enzyme industry failed to show interest in partnering with EERE to develop low-cost enzymes for cellulosic ethanol production. Only in 2000-2001, did they make the strategic decision to become key players in the development of the new ethanol industry. Feedstock collection infrastructure is another critical area in which industry has neglected to invest in the development of new technology. This development will require active public/private collaboration before cellulosic ethanol can effectively compete in fuel markets.

Baseline Market Acceptance

Gasoline is a mix of both high- and lower-value petroleum-based components, with the high-value components comprising only a small fraction of the total volume. With current ethanol tax incentives and ethanol's value to refiners due to its environmental and octane characteristics, corn-based ethanol is competitive with the small fraction of high-value petroleum-based constituents of gasoline that give gasoline acceptable octane and emissions levels. Therefore, a small amount of ethanol (10% or less) can be blended with 90% or more gasoline to produce a fuel that is competitive with conventional gasoline on a Btu basis. However, blending ethanol with gasoline in higher concentrations becomes less competitive because a gallon of ethanol has only two-thirds the energy of a gallon of gasoline, and it cannot compete with gasoline on a Btu basis. As the technology for producing cellulosic ethanol matures in the longer term, the retail value of cellulosic ethanol will become competitive with gasoline on an energy basis. At that point, fuel markets will rapidly accept nearly pure ethanol such as E85 because of its environmental characteristics and indigenous supply basis. Increases in market penetration for ethanol also will be affected by competition from other alternative transportation fuels and success in overcoming the lack of an established nationwide E85 transportation and distribution infrastructure. Eventually, increases in market penetration may be constrained by the availability of feedstock, rather than market demand.

Key Factors in Shaping Market Adoption

Price

The price of biomass-based fuels is sensitive to biomass feedstock costs, the impacts on production costs of biorefinery synergisms, and prices of competing fuels such as gasoline. The previous section discussed the value of ethanol in the low-blend market (E10) versus the high-blend market (E85 or higher blends).

Non-price Factors

In the E10 market, virtually all gasoline vehicles can use this low-blend ethanol gasoline mixture. For high blends such as E85, automobile manufacturers have considerable experience in producing vehicles that meet the Environmental Protection Agency's requirements due to a few million flex-fuel vehicles that have been sold in the United States, including models of the Ford Taurus, Chevrolet S10 pickup truck, GMC Sonoma pickup truck, Isuzu Hombre pickup truck, Chrysler Voyager minivan, Dodge Caravan minivan, Chevrolet Silverado, etc.

A 2002 study[8] on logistics barriers, sponsored by EERE, foresees no major infrastructure barriers to a substantial expansion of the ethanol industry in the scenarios it analyzes, which include substantial movement of ethanol among and within different regions of the country by several different modes of transport. The study reveals that a large number of investments in transportation, storage, terminalling, and retailing are possible without encountering significant "growing pains."

Although petroleum terminal improvements anticipated by the study represent significant capital investments for terminal operators, they amount to less than 1 cent per gallon of new ethanol volume on an amortized basis. In addition, with some assurance of increased throughput volumes at terminals (such as that provided by a Federal renewable fuel standard), terminal operators could be expected to make the improvements.

The volume of product anticipated to be moved by railroad and river barge is a very small fraction of products moved by these industries. Furthermore, both the rail freight car building industry and the barge building industry have the capacity to build equipment that would keep pace with the increasing ethanol shipments from new plants.

There also are operational strategies the ethanol industry could employ that would mitigate risk of supply disruptions caused by logistical glitches. Additional inventory levels at terminals and other storage locations could act as a cushion against delayed shipments and help ensure the smooth functioning of a growing market.

While the study did not find any serious logistical impediments to expansion of the ethanol industry, it did identify two areas of potential concern that merit further study. These are the availability of Jones Act/OPA90-compliant vessels and barge movement in some areas of the U.S. inland waterway system as a result of vessel retirements.

Ships that are used to transport ethanol are subject to various regulations and requirements. The Merchant Marine Act of 1920, otherwise known as the Jones Act, requires that all ocean or waterway transportation from one U.S. port to another U.S. port be moved in a vessel built in the United States, owned by a U.S. person or corporate entity, manned by a certified U.S. crew and registered in the United States (U.S. flagged). Tankers meeting these specifications are known as Jones Act tonnage.

Vessels carrying petroleum products between U.S. ports are also subject to the Oil Pollution Act of 1990 (OPA90). This would include ethanol because ethanol is normally transported after having been "denatured," with the addition of a small quantity of a petroleum product such as gasoline. OPA90 requires the use of double-hulled vessels and further requires the retirement of single-hulled vessels from petroleum product service by certain dates, based on their manufacture or rebuild date.

Key Consumer Preferences/Values

Both E10 and E85 are likely to penetrate the market more easily in the Midwest where ethanol already is a familiar fuel. In addition, if the trend of increasing public awareness and environmental concern continues, this could become a significant factor in consumer choice in fuel markets in other regions outside of the Midwest.

Manufacturing Factors

Cellulosic ethanol is envisioned as a major product – but not the only one – from a biorefinery. While various biorefinery configurations are possible, the two fundamental platforms are fermentation (sugar-based) and gasification (syngas-based). EERE is working with private industry to further develop these platforms, from which a host of fuels and chemicals may be derived. Initial plants will cost more in view of the perceived technical risks. As experience is gained with new plants, costs for each subsequent plant will decrease as a result of lessons learned and lower cost of capital associated with reduced risk. The Biomass Program has historically focused more on the fermentation platform for cellulosic ethanol, as this path was seen as a logical extension of the more mature starch-based ethanol process. Consequently, the National Renewable Energy Laboratory (NREL) and its subcontractors have extensively analyzed the process economics of the fermentation pathway. Because the focus on the syngas-based biorefinery is relatively new, our understanding of this pathway is not as developed as our understanding of the sugar-based pathway. For this reason, our analysis was limited to the sugar-based pathway.

Biorefinery configurations with integrated production of fuels, heat and power, and bio-based products need to be defined in more detail as soon as additional research data are available. While the relevant manufacturing factors are not fully understood, the need and overall process for contamination control in a sugar-based fermentation plant can be derived from the experience of current pharmaceutical and ethanol plants.

Policy Factors

In estimating the rate of market adoption, the analysis is based on the continuation of existing laws, regulations and policies (such as the ethanol tax incentive) and continuing USDA and DOE investment in biomass technologies RD&D at current levels, consistent with the Biomass R&D Act of 2000.

Methodology and Calculations

Inputs to Base Case

Table 2 contains the products of the analysis documented in this report, which serve as inputs to the NEMS-GPRA05 and MARKAL-GPRA05 integrated benefits analyses. NEMS-GPRA05 analysis extends through 2025, while MARKAL-GPRA05 analysis extends through 2050. The methodology employed to derive these inputs is described below.

Table 2. FY05 Ethanol Inputs (millions gallons per year)

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Corn	1600	1770	2130	2700	2725	2750	2800	2850	2900	2950	3000	3050	3100
Cellu	0	0	0	0	0	0	0	20	40	60	90	120	150
Total	1600	1770	2130	2700	2725	2750	2800	2870	2940	3010	3090	3170	3250
Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Corn	3150	3200	3200	3200	3200	3140	3140	3140	3080	3080	3080	3020	3020
Cellu	200	250	300	370	440	510	610	710	810	950	1090	1230	1410
Total	3350	3450	3500	3570	3640	3650	3750	3850	3890	4030	4170	4250	4430
Year	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**	**2045**	**2050**				
Corn	3020	2970	2970	2970	2920	2800	2680	2540	2380				
Cellu	1650	1930	2250	2610	3010	4610	6400	8300	10200				
Total	4670	4900	5220	5580	5930	7410	9080	10840	12580				

Technical Characteristics

For the sugar-based biorefinery concept, the analysis is based on a plant whose main product is fuel ethanol with coproduction streams of electricity and high-value chemicals and/or materials, which result in a reduced cost of ethanol due to the allocation of plant capital and operating costs across several products. The effect of the coproduction of electricity is inherent in the NREL cost estimates used in this analysis. A biorefinery credit was employed to account for the effect of other coproducts (chemicals and/or materials). The credit is 1 cent per gallon of ethanol produced in 2020 and gradually increases to14 cents per gallon by 2050. The high-value chemicals and/or materials that will be coproduced are not yet identified. The biorefinery credit is based on a moderate rate of technical success with respect to coproducts manufacturing and is considered by the analysts to be conservative.

Although the analysis considered competition for raw feedstocks (see discussion in next section), it did not explicitly consider the possible competition –between ethanol and chemical and materials coproducts – for the sugar stream within the biorefinery. Such competition can affect the ethanol production volume and conversion efficiency. This consideration will be included in future analyses, once biorefinery configurations and processes are better defined and understood.

The analysis is based on a biorefinery with a throughput of 2,000 dry tons of feedstock per day and with a conversion efficiency (in gallons of ethanol per dry ton of feedstock) increasing from 82 in 2020 to 101 in 2050 as a result of technological advances contemplated by the Biomass Program. This compares with current conversion efficiency of 70 gallons per dry ton.

Technical Potential

The biomass feedstock resources discussed here do not include wood waste and black liquor waste from paper mills, an important but captive resource—these resources are typically used within the forest and paper products industry. Under favorable R&D outcome and market scenarios, the upper bound for ethanol supply from U.S. biomass is estimated at 35 billion gallons per year, based strictly on feedstock availability. The farm-gate price and supply relationship for biomass used in the ELSAS model (for near-term conditions) are presented in **Table 3.**

Table 3. Farm-gate Biomass Quantities Supplied vs. Price Range (millions dry tons per year)

Feedstock excluding mill residues and black liquor	up to $20/dt	up to $30/dt	up to $40/dt	up to $50/dt
Forest Residues	0	12	20	70
Agricultural Crops Residues	0	6	65	80
Potential Energy Crops	0	5	120	280
Other Wastes	0	17	25	35
Total	0	40	230	465

The total is 465 million dry tons per year, at up to $50 per dry ton, before adding transportation costs to the biorefinery.

Some of the biomass likely will be used for fiber products, power, and chemicals. The fraction of feedstock evaluated for biofuels is shown below:

Forest Residues	0.4
Agricultural Crops Residues	0.8
Potential Energy Crops	0.8
Other Wastes	0.7

While forest residues and some of the "other wastes" may not be optimal for fermentation-based ethanol production, we recognized that future syngas-based fuels production may use forest residues and certain "other wastes" as feedstock. Therefore, the analysis is not deemed to be overly optimistic in spite of this year's focus on fermentation-based biorefineries for the GPRA analysis. After adding transportation costs from the source, such as the crop field or forest, the near-term supply for biofuels as a function of price per dry ton at the biorefinery gate is shown in **Table 4.** (Note that the maximum 465 million dry tons were reduced due to the fact that not all biomass will be used for biofuels production)

Table 4. Biorefinery-gate Quantities Supplied vs. Price Range (millions dry tons per year)

Feedstock excluding mill residues and black liquor	Up to $27.5/dt	Up to $40.0/dt	Up to $52.5/dt	Up to $65.0/dt
Agricultural Crops Residues	0	4.8	52	64
Potential Energy Crops	0	4.0	96	224
Forest and Other Wastes	0	17	25	52
Total	0	26	173	340

The annual quantity available to ethanol production, at up to $65 per dry ton (including costs of transportation to the biorefinery), is now 340 million dry tons. About 120 million dry tons per year at this price range would be available for other uses. In the longer term (2040, for example), crop yields increasing at the rate of 1% per year will result in additional biomass residues and the supply will be as shown in **Table 5.**

Table 5. Long-term Supply for Biofuels (millions dry tons per year)

Feedstock excluding mill residues and black liquor	Up to $27.5/dt	Up to $40.0/dt	Up to $52.5/dt	Up to $65.0/dt
Agricultural Crops Residues	0	7.1	77	95
Potential Energy Crops	0	4.0	96	224
Forest and Other Wastes	0	17	25	52
Total	0	28	198	371

At approximately 95-100 gallons of ethanol per dry ton of feedstock, the potential supply in the long term is at least 35 billion gallons per year.

Expected Market Uptake

Although the proposed Renewable Fuels Standard (RFS) is expected by many to be enacted, this analysis is limited to existing policies and does not include consideration of the RFS. Corn ethanol is projected to continue to expand as a result of various states' phase-outs of MTBE, but only to 3.2 billion gallons/year by 2014 compared with approximately 5 billion gallons/year under the proposed RFS. Future cellulosic ethanol capacity will slowly replace corn ethanol capacity as the new technology becomes more and more competitive relative to corn ethanol.

Corn ethanol plants are projected to develop and improve their ability to process corn fiber, a cellulosic feedstock, into ethanol (in addition to their continuing production of ethanol from corn starches) in the 2007-2022 time frame. Beginning in 2007, some municipal solid wastes also will be converted into ethanol (the Masada project in New York and similar projects). Beginning in 2019, biorefineries producing ethanol as a major product (along with high-value coproducts) from biomass wastes and residues will begin operation. Note that a number of other, non-ethanol biorefineries would have started producing before 2019, as described in the previous section on bio-based products analysis for input to NEMS-GPRA05. Eventually bio-energy crops, such as fast growing grasses, also will supply the biorefineries.

The analytic tool ELSAS was used to estimate ethanol market penetration, based on a moderate biorefinery credit resulting from coproducts that would enhance biorefinery economics. The following section describes the ELSAS tool and its use for this analysis.

Methodological Approach

Biomass ethanol market penetration analysis was accomplished through the integration of the results of various analyses conducted primarily by national lab personnel and their subcontractors, employing different specialized tools. ELSAS served as the integrating tool.

The following discussion provides a brief overview of ELSAS and the integration methodology.

Integration of Component Analyses

Three components of biomass ethanol analysis are integrated using ELSAS. These components are feedstock supply data, conversion technology data, and ethanol demand data. These three components are described in greater detail in the following sections.

ELSAS is a spreadsheet-based economic equilibrium analysis tool that integrates these three sets of data – along with additional technical, economic, policy, and financial variables – to derive ethanol supply and demand curves and determine market penetration (see **Figure 2,** depicting the inputs and outputs of ELSAS).

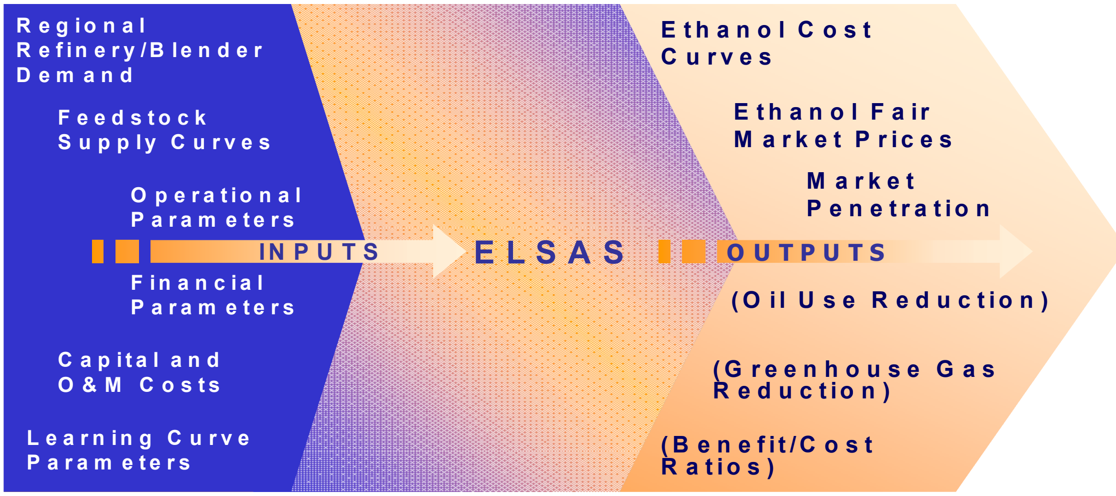

Figure 2. ELSAS Input and Output Parameter Categories

The model depends on an estimate[9] of near- to mid-term technology development by NREL as the starting point for a learning-curve cost-reduction algorithm for the technology used to convert feedstocks into ethanol. Dartmouth University professor Lee Lynd's estimates[10] of the expected long-term improvement in cellulosic technology were adapted to bound the other end of the learning curve. Using these boundaries, the learning curve equation was developed through the use of a curve-fitting process applied to various estimates made by NREL of the cost of ethanol from production facilities of increasing sophistication, with some modification by the Department of Energy. The learning curve provides the cost of the non-feedstock components of ethanol cost for each given year in the analysis period. The model combines this data with feedstock cost and supply-availability data to generate the cost and incremental supply of ethanol available for a given year.

For the last year in each five-year increment (to 2050), ELSAS balances supply and demand of ethanol by establishing a market-clearing price. For supply levels greater than the amount of corn starch-based ethanol production, the marginal cost of ethanol supply at each five-year increment is determined by cellulosic ethanol production costs (which generally decline in the analysis due to the operation of the learning curve) and feedstock costs (which can increase with increasing volumes of feedstock use).

Quantities demanded at different prices are represented in a demand curve for ethanol. For the last year in each five-year increment, supply and demand are balanced through a market-equilibrium price. The production of corn starch-based ethanol for that year is subtracted from the total demand for ethanol to calculate the total volume of cellulosic ethanol produced. Quantities of cellulosic ethanol produced in the first four years in the five-year increment are determined by interpolation. This process of determining market-equilibrium quantities and prices is performed for each five-year increment to 2050.

While ELSAS is an ethanol market-penetration analysis tool rather than a biorefinery market analysis tool, the inclusion of a biorefinery credit effectively creates the first step in the direction of an integrated market model for various biomass applications. While presenting results primarily in terms of cellulosic ethanol, it provides for the economic consequences of other uses of biomass feedstock, and models the economic impacts on ethanol production of generic (or nonspecific) biorefinery technology. This biorefinery credit is described above in the section on Technical Characteristics.

The time frame used in this analysis and the relative immaturity of biorefinery technology creates considerable uncertainty in this analysis. Numerous unforeseen advances in technology are likely to impact these projections. However, the results indicate long-term economic value based on the successful achievement of EERE's goals for biomass technologies, with adequate feedstock at economically viable costs in the long term to support multiple uses.

Additional details regarding the three primary data-input components and their treatment within ELSAS are presented below.

Feedstock Supply

Oak Ridge National Laboratory (ORNL) developed cellulosic feedstock supply curves with the aid of BIOCOST[11], POLYSYS[12], and other regionally detailed models. The feedstock supply-curve information shows quantities of different categories of cellulosic feedstocks available at different prices and time periods. This information is used by ELSAS at a national level of aggregation. The current ELSAS GPRA case uses data developed by Arthur D. Little, Inc.,[13] which was adapted from ORNL feedstock data. These data were modified based on more recent ORNL work on agricultural residue availability and cost[14].

Within ELSAS, the feedstock costs were adjusted to include transportation charges from the farm gate to the conversion facility, and feedstock supplies were allocated among different competing uses as described above in the Technical Potential section. In addition, the analysis assumes that agricultural residues will increase at an annual rate of 1% during the analysis period, due to increasing agricultural productivity. This assumption yields a total U.S. feedstock supply in 2040 approaching 370 million dry tons of agricultural residues, forest wastes, energy crops and other biomass wastes, after excluding potential competing uses.

Ethanol Conversion Cost

Ethanol conversion technology characterizations, in conjunction with feedstock costs, determine ethanol production cost. NREL, which conducts research and development work (in partnership with industry and universities) aimed at developing cost-competitive processes for producing ethanol from cellulosic feedstocks, develops estimates of production costs. Sale of electric power as a by-product of plant operations is also a factor for some cases. Surveys by the U.S. Department of Agriculture[15], industry publications, and other sources are used to estimate costs for corn grain-based ethanol.

Production-cost calculations in ELSAS make use of several different elements. First, an estimate of the conversion efficiency of feedstock into ethanol is derived. This efficiency is a function of date, which increases in the future as a result of R&D success envisioned by the program. This allows the feedstock component to be converted into one of the components of cellulosic ethanol cost. Next, near-term to mid-term estimates of the non-feedstock cost component are selected by the user, based on the Biomass Program's input. The default conversion efficiency and non-feedstock component of production cost are based on the program's studies published by NREL.[16] Then, a long-term, lower-bound estimate of the same component cost is selected, consistent with long-term goals. Cost reductions are modeled over time with a learning curve methodology, which projects technology improvements with increasing, cumulative industry production. The non-feedstock cost component is not allowed to fall below the lower bound. The user may modify the default values for conversion efficiency if new data are available. The parameters of the learning curve equation also can be varied by the user if new data suggest the need for doing so.

Ethanol Demand

Demand curves for ethanol (for use as a blending component with gasoline) are developed by ORNL under the direction of Jerry Hadder. The value of ethanol to refiners based on its blending characteristics (octane rating, toxic dilution, sulfur dilution, effect on Reid vapor pressure in summer RFG, etc.) is considered, along with crude oil and gasoline price projections, public policy variables, and numerous technical and economic factors relating to oil refinery operations. Analyses are developed with the use of the ORNL Refinery Yield Model (ORNL-RYM), a linear programming tool that simulates oil refinery operations. For a given set of input assumptions, the results of the ORNL analysis show quantities of ethanol demanded by refineries for blending with gasoline at different prices. Procedures were developed to modify RYM outputs to different world oil price scenarios. When complete RYM data has not been available, other analytical results (from a similar refinery linear program operated by MathPro) were used along with RYM outputs. Ethanol intra- and inter-regional transportation costs also are considered.

Benefits Estimation

The factors used by NEMS-GPRA05 and MARKAL-GPRA05 for calculating reductions in fossil energy use and carbon emissions were derived from the EERE Environmental Benefits Model GREET. The **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET) model is maintained by Argonne National Laboratory and is widely used within EERE, by industry, universities, and other government agencies, including those in several other countries. GREET contains characterizations of several biomass feedstock sources, including herbaceous and woody biomass, corn, and soybeans. GREET models many transportation fuels and vehicle technologies and includes representations of major electricity generation sources. GREET can compare energy and emission changes for alternative technologies, relative to a base technology in a unified and consistent way.

Endnotes

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Appendix C – GPRA05 Building Technologies Program Documentation

Introduction

Table 1 outlines the activities characterized for the GPRA05 Building Technologies Program. Characterizations and inputs for these activities were provided to EERE as inputs to EERE's integrated modeling effort.

Table 1. Building Technologies Subprograms, Projects, and Activities

Subprogram	Project	Activity
Residential Buildings Integration	Research & Development: Building America	Research & Development: Building America
	Residential Building Energy Codes	Residential Building Energy Codes
Commercial Buildings Integration	Research & Development	Research & Development
	Commercial Building Energy Codes	Commercial Building Energy Codes
Emerging Technologies	Lighting R&D	Lighting R&D: Controls
		Solid State Lighting
	Space Conditioning & Refrigeration R&D	Refrigeration R&D: Res. HVAC Dist. System
		Refrigeration R&D: Adv. Elec HPWH
		Refrigeration R&D: Commercial Refrigeration
		Refrigeration R&D: Refrigerant Meter
	Appliances & Emerging Technologies R&D	Appliances & Emerging Tech R&D: HPWH
		Appliances & Emerging Tech R&D: Roof Top AC
		Appliances & Emerging Tech R&D: Recessed Can Lights
		Appliances & Emerging Tech R&D: R-Lamp
	Building Envelope R&D: Window Technologies	Window Technologies: Electrochromic Windows
		Window Technologies: Superwindows
		Window Technologies: Low-E Market Acceptance
	Analysis Tools and Design Strategies	Analysis Tools and Design Strategies
Equipment Standards and Analysis	Equipment Standards and Analysis	Standards: EPAct Standards
		Standards: Distribution Transformers

Often such analysis requires the development and use of enabling or simplifying assumptions. In many cases, no citable sources exist for substantiating assumptions. Therefore, assumptions are developed through an iterative process with project managers, project contractors, and GPRA analysts. Often, we base these assumptions on project knowledge and experience, as there are varying degrees of corroborative studies available on which project information can be substantiated, depending on the maturity of the project

1.0 Residential Buildings Integration

The long-term goal of Residential Buildings Integration is to develop cost-effective designs for net Zero Energy Buildings (ZEB)—houses that produce as much energy as they use on an annual basis—by 2020.

1.1 Residential Building Energy Codes

1.1.1 Target Market

Project Description. The Residential Building Energy Codes project improves the minimum or baseline energy efficiency of new residential buildings requiring code permits. The project promulgates upgraded energy efficiency requirements for residential buildings. Similarly, the project works with model energy code groups to upgrade the energy efficiency requirements of their codes. Federal, state, and local jurisdictions then adopt and implement these upgraded federal and model energy codes. The long-term goal is to improve the minimum energy efficiency by 20% to 25% in new low-rise residential building construction.

Market Description. The market includes new residential low-rise buildings three stories or less in height and all additions and renovations to buildings requiring code permits.

Size of Market. Each year, nearly 1.6 million residential building permits are issued, approximately 80% of which are single-family dwellings. Although not all jurisdictions currently have energy efficiency building codes in place, the Pacific Northwest National Laboratory (PNNL) estimates that about half of all new residential construction comes under building energy code requirements. Also, consumers spend several billion dollars a year on remodeling and renovating projects in private residences, about half of which could be covered by an energy code. One market not covered by codes is manufactured homes, which fall under Housing and Urban Development (HUD) jurisdiction and regulations.

Baseline Technology Improvements. Initial compliance with new codes was assumed to be lower in the base case, i.e., without the Building Energy Codes project, than with the project. For FY05, the percentage of potential savings, in the first year of the single future code, was assumed to be approximately 35% for heating and cooling measures without the project.

Baseline Market Acceptance. Under the baseline scenario, 23 states were assumed to have adopted the IECC 2000 or IECC 2003 standard by the end of 2005. The GPRA estimates were partly based on states' accelerated schedule of adoption of the IECC 2000 and IECC 2003 codes. Through the efforts of the Building Energy Codes project, 37 states were assumed to have adopted the 2000 or 2003 standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of three years nationwide.

1.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a five-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $5). This corresponds to a total incremental cost of approximately $120 million in 2010, $285 million in 2020, and $300 million in 2030.

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered.

- Improved environment and more comfortable buildings.
- Lower utility bills
- Lower home maintenance and repair activities
- Reduced pollution due to the reduced burning of fossil fuels and electricity generation, which improves air quality and mitigates the negative impacts of global warming.

1.1.3 Methodology and Calculations

Inputs to Base Case. With respect to codes, it is indeterminate as to whether potential future code improvements are incorporated into the National Energy Modeling System GPRA 2005 (NEMS-GPRA05) base case. The NEMS-GPRA05 base case does include some improvements to the building shell efficiency; however, the basis for these improvements (e.g., general building-practice improvements, changes in codes requirements, improvements in materials) is not specified by the Energy Information Administration (EIA). Codes that have been issued (but that have not gone into effect) may be included in the NEMS-GPRA05 base case, but would not be included in the GPRA forecast of savings for that activity, because it no longer would be funded. Only an estimate of potential future codes is included in the GPRA estimates. Therefore, PNNL did not provide inputs to change the base case assumptions for the program markets.

Technical Characteristics. The FY 2005 GPRA estimates are based on increased compliance with existing codes, accelerated adoption of the 2000 editions of the International Energy Conservation Code (IECC) code (to comply with Section 304 of the Energy Conservation and Production Act), and the future development of more stringent building codes. The energy-savings methodology was applied at a state level to better link changes in the national codes (e.g., IECC 2000) with variations in climate by states (and differences among states) in their adoption and enforcement of building codes. This discussion uses national averages of some of the key assumptions related to adoption and compliance to help summarize the methodology.

The principal difference between the 1995 Model Energy Code and the IECC 2000 involves the solar heat gain requirements for windows and increased thermal resistance requirements for ducts in unconditioned spaces. Based on a series of simulations for various U.S. locations, the percentage reduction in cooling load was estimated to be about 15%. This requirement increases the heating load by a small amount, about 2% nationally. (The requirement itself is restricted to the southern tier of states). The GPRA estimates were partly based on states' accelerated schedule of adoption of the IECC 2000 and 2003 codes. Through the efforts of the Building

Energy Codes project, 31 states were assumed to have adopted the standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of three years nationwide.

The IECC's ongoing activities were assumed to lead to more stringent residential standards in the future. The Department of Energy (DOE) was assumed to play a major role in developing the analytical and economic basis for such standards. For the GPRA process, these activities were subsumed in a single upgrade of the IECC standard assumed to become available in the latter part of the current decade. Based on discussions with Building Technologies (BT) staff, PNNL assumed that the results of these upgrades were to reduce heating and cooling loads in new residential structures by 10%. Without these activities, the analysis assumed that the same standard would be adopted, on average, three years later.

> *Relationship to WIP.* EERE's efforts to support building codes covers two aspects: 1) the development of new codes with greater stringency or ease of enforcement and 2) activities to improve the compliance with codes and to accelerate adoption of the most recent codes by states and localities. The development of new codes is supported by the Building Technologies Program and efforts to improve compliance and accelerate adoption are supported in the Weatherization and Intergovernmental Program (WIP). The methodology to develop the total effect from these two EERE programs is integrated. The documentation below discusses both aspects of EERE activities with regard to energy codes.
>
> More explicitly for modeling purposes, the GPRA energy savings estimates for BT (in regard to codes) is restricted to the development of a single new national residential code, expected to publish in the latter part of the current decade. However, with the ongoing efforts to promote adoption and compliance, the impact of the published code would be modest. However, without development of a new code, activities to promote adoption and compliance would be meaningless. Thus, the issue becomes assignment of savings from future code between the BT and WIP programs. In the GPRA estimates for 2005, 50% of the savings attributable to accelerated adoption and increased compliance of the new code were allocated to the BT program.

Expected Market Uptake. The project's activities also were assumed to improve compliance rates for codes currently adopted by states and localities, as well as future building codes. Compliance is increased through better familiarity with the codes, simplifications to the code while maintaining stringency, and the availability and increased use of compliance tools by builders and enforcement officials. Compliance rates, with and without the project, were estimated for various standards as discussed above. The compliance with the several key provisions in the IECC 2001 and 2003 (compared with the 1995 Model Energy Code) was expected to be higher from the outset. On average, the compliance was estimated to be 68% in the year of the adoption. By 2010, compliance rates were assumed to increase to 69% without the project and 74% with the project. For homes that do not comply with the standard, only half of the incremental energy savings were assumed to be achieved by adopting IECC 2001 or 2003.

The analysis assumed that when states first adopt the new standard (assumed to become available in the 2006-2007 time frame), the potential energy savings from going to the new standard is 85% at the time of adoption, increasing to 90% with the project after the first 10 years.

1.2 Research and Development: Building America

1.2.1 Target Market

Project Description. The project's long-term goal is to develop advanced systems to improve the energy performance of residential new homes by 70% relative to homes built under the Model Energy Code, 1995 edition (MEC95), and to reduce existing home energy use by 20% over current use. Ultimately, the goal for single-family homes is to achieve a cost-effective, marketable zero-net energy home design by integrating renewable energy (initially solar electric and solar thermal) into home designs.

Market Description [1,6]: The target market includes all new residential homes. Existing homes also would benefit from new technologies and improved construction practices developed for new homes. For the FY 2005 GPRA effort, potential impacts to the existing residential market were not explored.

Size of Market[7]**:** Each year about 1.2 million new housing units are built. In 2002, 976,000 new single-family homes were built. These units are primarily owner occupied.

Market Introduction: 1997[2]**;** Initial penetration of renewable energy designs began in the southwest in 2003[6]. The on-site renewable energy technology research is anticipated to expand into the northern climate zones beginning in 2008. While renewable technology currently exists (e.g., solar thermal, photovoltaics), penetration into the general market is expected to continue to be extremely low without DOE R&D funding, because the technology is currently unaffordable for production home builders. PNNL assumed that residential R&D activities would not occur in the absence of DOE R&D funding, therefore, this project was not assumed to accelerate the market acceptance of these practices.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

1.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price.
Building America Whole House Energy Savings:
Cost of BT Technology:[5] 2% above conventional cost[4].
Incremental Cost (average price per household):

- Single Family: $2,500
- Multifamily: $1,500
- Manufactured Home: $800.

Renewable Portion:
Incremental Cost (average price per household):

- Single Family: $31,000 declining to $9,100 by 2020. [6]

Key Consumer Preference/Values – Nonenergy Benefits.[1] The cost and performance characteristics were used to model this project in NEMS-GPRA05/MARKAL-GPRA05. The following nonenergy characteristics were not considered in the model:

- Improved comfort, durability, and occupant health from better indoor air quality
- Reduced on-site generated waste
- Better sustainability
- Reduced maintenance.

1.2.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. Reduce whole-house energy use by 40%, increasing to 70% in 2030. The renewable energy technologies also are credited with displacing energy supply with solar or other renewable technologies, such that an additional 10% in fossil fuel savings is achieved by 2010, increasing to 30% by 2020.

Technical Potential. The technical energy savings potential for this project includes all primary energy consumption in the residential sector, or 20 QBtu (Table 1.2.3, page 1-6 of *2003 Buildings Energy Databook*). Up to 70% of current residential building energy use would eventually (by 2030) be reduced through advanced building practices and technologies; with the remainder of the building load met using photovoltaic, solar thermal, and other on-site renewable technologies.

Expected Market Uptake. PNNL assumed that this activity would not occur in the absence of DOE funding, therefore, no acceleration of market acceptance was modeled. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). **Table 2** displays the resulting estimated number of homes impacted based on the penetration curves developed.

1.2.4 Sources

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(7) Based on Impacts spreadsheet developed by Ren Anderson, National Renewable Energy Laboratory, December 22, 2003, Confirmed by Ren Anderson in January, 2004.
(8) "The BUILDER 100 Database" at www.builderonline.com, accessed August 8, 2003.
(9) New Houses Sold, by Region, by Sales Price: Annual Data. U.S. Census Bureau, Manufacturing and Construction Division. www.census.gov/const/regsoldbypricea.pdf, accessed August 8, 2003.
(10) BTS Core Databook (July 26, 2003), Table 5.1.1., "2001 Five Largest Residential Homebuilders."

Table 2. FY 2005 Market Penetration for Residential Technology R&D Projects (7)

Year	BA Annual No. Homes	Annual Homes Impacted by Renewable Technologies Supported by Project
2005	50,065	2,514
2006	78,420	5,667
2007	115,625	9,500
2008	157,704	16,238
2009	200,148	23,744
2010	250,888	33,048
2011	293,699	42,121
2012	317,715	48,992
2013	334,054	54,865
2014	355,265	61,637
2015	364,470	66,282
2016	375,111	70,983
2017	374,436	73,223
2018	377,371	75,792
2019	385,194	79,024
2020	383,500	80,000

2.0 Commercial Buildings Integration

The long-term goal of this subprogram is to develop cost effective designs for commercial buildings that produce as much energy as they use on an annual basis. Research will focus on reducing total energy use in a commercial building by 60% to 70%.

2.1 Commercial Building Energy Codes

2.1.1 Target Market

Project Description. The Commercial Building Energy Codes project improves the minimum energy efficiency of new commercial and multifamily high-rise buildings and additions and alterations to existing buildings requiring code permits. The project promulgates upgraded energy efficiency requirements for Federal commercial and high-rise residential building types.

Similarly, the project works with model energy code groups to upgrade the energy-efficiency requirements of their codes. These upgraded national energy standards are then adopted by Federal, state, and local jurisdictions as part of their building codes. The project's long-term goal is to improve minimum energy efficiency by 30% to 35% in new commercial building construction. Energy use will be reduced by states and local jurisdictions widely adopting the national standards as building energy codes.

Market Description. The market includes new commercial and multifamily high-rise (above three stories) buildings and all additions and renovations to commercial buildings requiring code permits.

Size of Market. The commercial market size is about 2 billion square feet of new commercial floor space each year. The Federal sector represents nearly 2.3% overall of new commercial building construction.

Baseline Technology Improvements. Initial compliance with new codes was assumed to be lower in the base case, i.e., without the Building Energy Codes project. For FY05, the percentage of potential savings, in the first year of the single future code, was assumed to be approximately 20% for envelope measures and 30% for lighting measures without the project.

Baseline Market Acceptance. The FY 2005 GPRA estimates are based on increased compliance with existing codes, accelerated adoption of the 1999 and 2001 editions of ASHRAE 90.1-1999(4) standard (to comply with Section 304 of the Energy Conservation and Production Act), and the future development of more stringent building energy codes. Through the efforts of the Building Energy Codes project, 21 states were assumed to have adopted the standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of four years nationwide.

2.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a five-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $5).

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered.

- Improved environment and more comfortable buildings.
- Lower utility bills
- Lower home maintenance and repair activities
- Reduced pollution due to the reduced burning of fossil fuels and electricity generation, which improves air quality and mitigates the negative impacts of global warming.

2.1.3 Methodology and Calculations

Inputs to Base Case. With respect to building codes, it is indeterminate the extent to which potential future code improvements are incorporated into the NEMS-GPRA05 base case. The NEMS-GPRA05 base case does include some improvements to the building shell efficiency; however, the basis for these improvements (e.g., general building practice improvements, changes in code requirements, improvements in materials) is not specified by EIA. The impact of accelerated adoption and improved compliance by states of recently issued national building standards (e.g., IECC 2003) is included in the GPRA forecast of savings. The GPRA savings estimates for WIP also include a portion of the impact of changes in building codes that are anticipated within approximately the next 10 years. (A portion of the savings from increased stringency of future codes is also allocated to the Building Technologies Program). Therefore, PNNL did not provide inputs to change the base-case assumptions for the program markets.

Technical Characteristics. Energy savings from this project result from some basic improvements to the overall energy efficiency of commercial buildings in their space-heating, space-cooling, and lighting loads. This project funds research analysis of cost-effective levels of energy codes for new commercial and multifamily high-rise buildings. This BT program works with the Training and Assistance for Codes project within the Office of Weatherization and Intergovernmental Programs, which funds the development of core materials (such as compliance tools and training materials) and provision of training and financial and technical assistance for states to update and implement their building energy codes. Benefits cannot be clearly allocated to either project, thus the benefits estimated are a function of both training and deployment as well as development of the commercial building energy codes and standards.

Savings estimates for commercial codes are based on increased stringency from the combined impact of the forthcoming ASHRAE 90.1-2004 code and the “next” code assumed to be published in 2007. For FY05, future codes (up through 2010) are assumed to achieve a total reduction of 18% in electricity and a 10% reduction in natural gas as compared to 90.1-1999, based on a series of simulations for various U.S. locations. Benefits for FY 2005 were assumed to be allocated according to the ratio of actual funding levels.

The project impacts energy consumption through two primary avenues: 1) developing and supporting code changes to improve the minimum energy efficiency requirements for commercial and multifamily high-rise buildings and 2) providing technical and financial assistance to states to update and implement their building energy codes. The latter includes developing tools that can ease the adoption of new codes and through their use, can support improvements in compliance and enforcement of code provisions. Tools take the form of code compliance software, computer-based training tools for building energy codes, and tools for implementing noncomputer-based codes.

Improvements to building codes are primarily supported by research efforts to review existing codes and specific targeted areas of building energy use, as well as the adoption of code modifications that promote cost-effective reductions in these energy-use areas. Support for the research work has typically taken place in three areas:

- Upgrading ASHRAE/IES Standard 90.1-1989, "Energy-Efficient Design of New Buildings Except Low-Rise Residential Buildings"(1)
- Upgrading the Federal commercial and multifamily high-rise building energy code, 10 CFR 434, "Energy Code for New Federal Commercial and Multi-Family High Rise Residential Buildings"(2)
- Upgrading the International Energy Conservation Code (IECC).(3)

The FY 2005 GPRA estimates are based on increased compliance with existing codes, accelerated adoption of the 1999 and 2001 editions of ASHRAE 90.1[4] standard (to comply with Section 304 of the Energy Conservation and Production Act), and the future development of more stringent building energy codes. The energy-savings methodology was applied at a state level to better link changes in the codes with variations in climates by states and differences among states in their adoption and enforcement of building codes. The discussion below uses national averages of some of the key assumptions related to adoption and compliance to help summarize the methodology, but appropriate state averages were used in the analysis.

The principal differences between the ASHRAE 90.1-1989, 90.1-1999, and 90.1-2001[5] standards relate to requirements for better windows, reduced installed wattage for lighting, and more efficient heating and cooling equipment. The savings from improved equipment are not included in the project's savings estimates, because they are reflected in the Equipment Standards and Analysis decision unit in this appendix. Based on a series of simulations that include various U.S. locations and that were developed specifically to evaluate the two ASHRAE standards (often referred to as the "determination" study[6]), the average reduction in site energy use was estimated to be about 3.5% or 2 MMBtu/sq ft. The GPRA estimates were partly based on states' accelerated adoption schedule of the ASHRAE 90.1-1999 and 90.1-2001 standards. Through the efforts of the Building Energy Codes project, 21 states were assumed to have adopted the standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of four years nationwide.

The ongoing activities of the ASHRAE 90.1 committee were assumed to lead to more stringent commercial-building standards in the future. DOE was assumed to play a major role in developing the analytical and economic basis for such standards. For the GPRA process, these activities were subsumed in a single upgrade of the ASHRAE standard, assumed to become available in the latter part of the current decade. The GPRA analysis assumed that the overall result of these upgrades is to reduce electricity consumption by 10% and natural gas consumption by 10% in new commercial buildings. Many states adopting this standard by 2010 also depends on the project's continuing activities to assist states in the adoption (and compliance) process. Without these activities, the analysis assumed that the same standard would be adopted, on average, six years later.

The project activities also were assumed to improve compliance rates for codes currently adopted by states and localities, as well as future building codes. Compliance is increased through increased familiarity with the codes, simplifications to the code while maintaining stringency, and the availability and increased use of compliance tools by builders and enforcement officials. Compliance is effectively measured as the percentage of potential savings moving from one code to the next. Compliance rates estimated between the existing code (assumed to be 90.1-1989) and a code based on ASHRAE 90.1-1999; and between 90.1-1999 and a new code discussed above.

Without the program, the percentage of potential savings is assumed to be modest, as the program is directed toward software tools and training that facilitate adherence to the code. In this case, on average, PNNL estimated the percentage of potential energy savings for envelope measures to be about 20% in the year of adoption. Ten years later, the percentage of potential energy savings is assumed to increase to approximately 50%. For lighting, these percentages were 30% and 55%, respectively. With the program, the percentage of potential energy savings is expected to be higher at the outset and increase more rapidly. For envelope measures, the initial potential savings is about 70%, increasing to about 95% 10 years later. For lighting measures, the initial percentage of savings is 80%, again increasing to about 95% years later.

Expected Market Uptake. As part of work for an unpublished analysis of the historical impacts of Building Energy Codes in August 2003, the assumptions regarding the acceleration effect of the program were modified (e.g., program activities leading to states adopting codes more rapidly than they would have otherwise). In general, the states were classified into groups that: 1) immediately adopted the ASHRAE 90.1-1989 code, 2) would have adopted within five years without the building codes project, or 3) would have adopted within 10 years without the building codes project. These time periods were then reduced by one year for each successive major code cycle after the 1989 code. (For example, a five-year lag for 90.1-1989 is assumed to fall to three years for the forthcoming ASHRAE 90.1-2004 code). The overall impact of this change was to decrease the average lag between the publication of a new standard and when it is adopted without the project. This modified set of assumptions increases the overall estimate of the future energy savings impact from the program.

2.1.4 Sources

(1) ASHRAE/IES Standard 90.1-1989, "Energy Efficient Design of New Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers and Illuminating Engineering Society.
(2) 10 CFR 434, "Energy Code for New Federal Commercial and Multi-Family High Rise Residential Buildings," *Code of Federal Regulations*, as amended.
(3) International Energy Conservation Code. 2003. International Code Council, Falls Church, Virginia.
(4) ASHRAE/IES Standard 90.1-1999, "Energy Standard for Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers.
(5) ASHRAE/IES Standard 90.1-2001, "Energy Standard for Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers.
(6) U.S. Department of Energy. March 2002. "Commercial Buildings Determinations, Explanation of the Analysis and Spreadsheet (90_1savingsanalysis.xls)." http://www.energycodes.gov/implement/determinations_com.stm

2.2 Technology Research and Development

2.2.1 Target Market

Project Description. The Commercial Buildings Integration subprogram develops and demonstrates advanced technologies, controls, and equipment in collaboration with the design and construction community. The project focuses on advancing integrated technologies and practices to optimize whole-building energy performance. The project reduces energy use in commercial and multifamily buildings by promoting practices that help ensure the industry constructs buildings as designed and operates them at or near the optimum level of performance. The project's long-term goal is to improve the energy efficiency of the nation's new commercial buildings by 30% and existing buildings by 20% compared with buildings built in 1996.

Market Description: Although this project does not explicitly exclude any particular building type, the types of commercial buildings that most likely will be impacted by the technologies developed by this project include buildings with relatively higher energy use intensities such as assembly, education, health care, lodging, and office buildings.

Market Introduction[(2)]: PNNL assumed that this project accelerates the adoption of relevant energy-savings products, technologies, and designs by 10 years.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

Baseline Market Acceptance. In 1998, PNNL conducted a study examining the historical market penetration for 10 energy-efficient products related to the buildings sector. The results of this study are documented in the PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)[(5)]. The study suggested several generic penetration curves based on the type of equipment of interest. PNNL used the curve related to design products to model this project.

2.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price.
Cost of Conventional Technology:[(3)] Average of \$101/ft^2 for the targeted new commercial and multifamily; \$0 for existing buildings.
Cost of BT Technology: \$103/ft^2 for new commercial and multifamily; \$3/ft^2 (2001 to 2009), increasing to \$4/ft^2 (2010 to 2030) for existing buildings.
Incremental Cost:[(2)] 2% above base for new buildings; \$3/ft^2 (2005 to 2009), increasing to \$4/ft^2 (2010 to 2030) for existing buildings.

Key Consumer Preference/Values – Nonenergy Benefits.[(1)] The following nonenergy characteristics were not considered in developing energy-output estimates:

- Reduced operation and maintenance expenses
- Improved indoor environmental quality
- Increased property asset value
- Higher tenant satisfaction and retention rates
- Increased technology sales.

2.2.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. Together with the Analysis Tools and Design Strategies Project, this project has the following performance goals:

- By 2004, reduce heating and cooling loads by 30% in new construction and by 20% in existing units
- By 2010, reduce heating and cooling loads by 50% in new construction and by 30% in existing units.
- By 2020, reduce heating and cooling loads by 60% in new construction and 40% in existing units.

Technical Potential. Approximately 2 QBtu in 2005. The technical energy-savings potential for this project includes all heating, cooling, and water-heating primary energy consumption (5.3 QBtu) for about 70% of the commercial-building sector. Because the maximum performance goal for this program is a 60% reduction in these end uses, the technical potential is 5.3 QBtu * .60 * .70 = 2.2 QBtu. Table 1.3.3, page 1-10 of *2003 Buildings Energy Databook.*

Expected Market Uptake. The market-penetration goal is to accelerate the penetration of high-performance building designs, such that 60% of new commercial and multifamily construction – and 20% of existing construction—incorporates the products supported by this project by 2020. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). PNNL assumed that this project accelerates the adoption of relevant energy-savings products, technologies and designs by 10 years.

2.2.4 Sources

(1) Interview with the project manager, Dru Crawley, August, 2001.
(2) E-mail correspondence with project manager, Dru Crawley, June, 2003.
(3) RS Means Company, Inc. 2002. *"RS MEANS Square Foot Costs"*. 23rd Edition, Kingston, MA.
(4) RS Means Company, Inc. 2002. *"RS MEANS Square Foot Costs"*. 23rd Edition, Kingston, MA.
(5) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

3.0 Equipment Standards and Analysis

This subprogram seeks to develop minimum energy efficiency standards that are technologically feasible and economically justified.

3.1 EPAct Standards

3.1.1 Target Market

Project Description. The EPAct standards were assumed to continue with the technologies having the potential for additional energy savings. These technologies include boilers, three phase residential size cooling equipment, packaged terminal air conditioning, packaged terminal heat pump equipment, and large rooftop air-conditioning equipment.

Market Description: The market includes all residential and commercial equipment covered by the appropriate legislation.[2,3]

Size of Market: The market size includes all applicable residential and commercial equipment in the market to which legislation applies (ovens/ranges and medical equipment, for example, are not covered).

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

3.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a nine-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $9). This corresponds with a total incremental investment cost of approximately $200 million in 2005, $1 billion in 2010, $1.4 billion 2020, and $600 million in 2030.

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy-output estimates:

- Reduced CO_2 and SO_X emissions
- Reduced water consumption from plumbing equipment
- Increased life of equipment operating at cooler temperatures
- Reduced first costs that transform new technologies into commodities.

3.1.3 Methodology and Calculations

Technical Characteristics. For FY 2005, the energy savings from equipment standards activities were based primarily based on a PNNL screening analysis conducted in late 1999 and early 2000[4] to provide preliminary estimates of the potential energy savings from updated commercial equipment standards. PNNL used the spreadsheet developed for this study to estimate the energy savings from various levels of standards for nearly 40 types of equipment covered by EPAct. The spreadsheet results were used to identify technologies that could achieve significant energy savings beyond the efficiency levels set in the recent ASHRAE 90.1-1999 publication.[5]

Based on the spreadsheet EPACT_SA.XLS (essentially identical to the spreadsheet installed on the BT Web site for public comment subsequent to the EPAct screening analysis), the tables below summarize the efficiency assumptions and energy-savings results for technologies that DOE/BT will further analyze. The key assumptions and results were summarized for 12 cooling technologies in **Table 3** and for boilers and a high-capacity instantaneous water heater in **Table 4.** Cumulative savings, shown in the last column in both tables, were based on the savings from the effective date of the standards through 2030.

Table 3. Key Assumptions and Results for Cooling Products

Equipment Category	Efficiency (SEER and EER)*			Energy Savings by Year (TBtu)			
	EPAct	New Std	Eff. Date	2010	2020	2030	Cum.
3-Phase Single Package, Air Source Air Conditioning, <65 kBtu/h	9.7	12.0	2005	4.6	21.0	26.5	396.0
3-Phase Single Package, Air Source Heat Pump, <65 kBtu/h	9.7	12.0	2005	1.2	3.1	3.4	60.2
3-Phase Split, Air Source Air Conditioning, <65 kBtu/h	9.7	11.0	2005	0.9	4.1	5.2	78.1
3-Phase Split, Air Source Heat Pump, <65 kBtu/h	9.7	12.0	2005	9.1	24.0	26.5	463.0
Central, Water Source Heat Pump, >17 and <65 kBtu/h	9.3	12.5	2008	1.5	7.1	11.1	146.9
Central, Air Source Air Conditioning, >=65 and <135 kBtu/h	8.9	11.0	2008	5.5	25.0	31.6	471.6
Central, Air Source Air Conditioning, >=135 and <240 kBtu/h	8.5	11.0	2008	5.4	24.6	31.0	463.1
Packaged Terminal Air Conditioning, 7-10 kBtu/h	8.6	10.8	2008	0.4	1.8	2.2	33.3
Packaged Terminal Air Conditioning, 10-13 kBtu/h	8.1	10.2	2008	0.6	2.6	3.3	49.5
* SEER = seasonal energy efficiency ratio; EER = energy efficiency ratio.							

Table 4. Key Assumptions and Results for Boilers and a High-Capacity Instantaneous Water Heater

Equipment Category	Efficiency (SEER and EER)			Energy Savings by Year (TBtu)			
	EPAct	New Std	Eff. Date	2010	2020	2030	Cum.
Pkg'd Boilers, Gas, 400 kBtu/h, Hot Water	75%	78%	2008	0.2	0.9	1.7	19.7
Pkg'd Boilers, Gas, 800 kBtu/h, Hot Water	75%	78%	2008	0.4	2.0	3.7	43.0
Pkg'd Boilers, Gas, 1500 kBtu/h, Hot Water	75%	78%	2008	0.1	0.7	1.2	14.2
Pkg'd Boilers, Gas, 3000 kBtu/h, HW	75%	80%	2008	0.2	0.7	1.3	15.2
Pkg'd Boilers, Gas, 400 kBtu/h, Steam	72%	76%	2008	0.1	0.6	1.1	12.6
Pkg'd Boilers, Gas, 800 kBtu/h, Steam	72%	76%	2008	0.4	1.6	3.0	34.5
Pkg'd Boilers, Gas, 1500 kBtu/h, Steam	72%	79%	2008	0.3	1.2	2.3	26.7
Pkg'd Boilers, Gas, 3000 kBtu/h, Steam	72%	80%	2008	0.2	0.9	1.7	19.2
Instantaneous Water Heaters, 1000 kBtu/h	80%	83%	2008	1.0	4.4	5.6	83.3

3.2 Distribution Transformers [a]

3.2.1 Target Market

Project Description. Distribution transformers convert high-voltage electricity from distribution centers to lower-voltage electricity for use at the household level. During this conversion process, a small fraction of heat is lost. Rules are being written to reduce the amount of heat loss during this conversion process.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

3.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a 10-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $10). This corresponds to a total incremental investment of approximately $580 million in 2010, $780 million in 2020, and $230 million in 2030.

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy-output estimates:

- Reduced CO_2 and SO_X emissions

3.2.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics
Performance Target: Savings estimates for a distribution transformer standard were based on a study conducted by Geller and Nadel.(7) The study assumed the following:

- Savings of 80 watts per unit
- 20% sales complying with the new level without the standard

Lifetime:

- 8,760 annual operating hours per unit
- 13-year life of equipment.

The savings estimate of 80 watts per unit installed was multiplied by the estimated hours of operation and then by the forecasted number of units installed.

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[a] Updated information on the FY05 characterization of the Distribution Transformer Standard project became available too late to become incorporated in the official GPRA estimates for FY05. Therefore, the FY04 characterization was used as a proxy. This results in an unspecified under-reporting of benefits for the FY05 budget that will be addressed for the FY06.

Expected Market Uptake

Table 5. Distribution Transformer Market Penetration

Year	Transformer Sales Forecast [8,9]
2005	1,623,086
2006	1,654,225
2007	1,685,962
2008	1,718,307
2009	1,751,273
2010	1,784,871
2011	1,819,115
2012	1,854,015
2013	1,889,584
2014	1,925,836
2015	1,962,784
2016	2,000,440
2017	2,038,819
2018	2,077,934
2019	2,117,799
2020	2,158,429
2021	2,199,839
2022	2,242,044
2023	2,285,057
2024	2,328,057
2025	2,373,577
2026	2,419,114
2027	2,465,525
2028	2,512,827
2029	2,561,036
2030	2,610,170

3.3 Sources

(1) FY 2002 Budget Request - *Data Bucket Report for the Lighting and Appliance Standards Program* (internal BTS document).
(2) National Appliance Energy Conservation Act of 1987, Public Law 100-12.
(3) Energy Policy Act of 1992, Public Law 102-486.
(4) Somasundaran, S. et al. 2000. *Screening Analysis of EPAct-Covered Commercial HVAC and Water Heating Equipment*. PNNL-13232, Pacific Northwest National Laboratory, Richland, Washington.
(5) ASHRAE 90.1-1999, "Energy Standard for Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers.
(6) *Annual Energy Outlook 2001*. 2001. Energy Information Administration, Washington, D.C.
(7) Geller, H., and S. Nadel. 1992. "Consensus National Efficiency Standards for Lamps, Motors, Showerheads and Faucets, and Commercial HVAC Equipment." In *American Council for an Energy Efficient Economy Proceedings*, pp. 6.71-6.82.
(8) Monthly Energy Review. May 2001. Table 7.1.
(9) *Annual Energy Outlook 2002*. 2002. Table 22. Energy Information Administration, Washington, D.C.

4.0 Emerging Technologies

The Emerging Technologies subprogram seeks to develop cost-effective technologies, e.g., lighting, windows, and space heating and cooling, for residential and commercial buildings that can reduce the total energy use in buildings by 60% to 70%. The improvement in component and system energy efficiency, when coupled with research to integrate onsite renewable energy supply systems into the commercial building, can result in marketable net zero-energy designs.

4.1 Analysis Tools and Design Strategies

4.1.1 Target Market

Project Description. The Analysis Tools and Design Strategies project researches the interrelationship of energy systems and building energy performance, develops various building analysis tools to more accurately model energy use in new and existing buildings, and provides recommendations and strategies to cost effectively lower energy use and improve building performance. The project focuses on whole-building software tools for evaluating energy efficiency and renewable energy. The project also focuses on nonsoftware solutions such as improved standards, guidelines, and performance measurements, all of which bring about excellence in designing new buildings.

Market Description: Although this project does not explicitly exclude any particular building type, the types of commercial buildings that most likely will be impacted by the technologies developed by this project include those with relatively higher energy-use intensities such as assembly, education, health care, lodging, and office buildings.

Market Introduction(2): 1996; PNNL assumed that this project accelerates the introduction and market penetration of the advanced building energy tools and design strategies by 10 years. Historically, there have been a number of building energy tools that have been developed privately; however, most of these tools use algorithms, code, and modules developed by DOE. PNNL assumes that a proportion of these activities (50%) would not occur without DOE funding. These assumptions are necessary in the absence of citable sources documenting DOE's influence on building energy tool adoption and algorithm attribution.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

Baseline Market Acceptance. In 1998, PNNL conducted a study examining the historical market penetration for 10 energy-efficient products related to the buildings sector. The results of this study are documented in the PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)(5). The study suggested several generic penetration curves based on the type of equipment of interest. PNNL used the curve related to design products to model this project.

4.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Although the tools supported by this project are distributed free of charge, users must invest a certain amount of time to learn the tools. Without a user-friendly interface, approximately one person-month is required to be come proficient with the tools. Analysis Tools and Design Strategies is currently developing energy-simulation tools without a user-friendly interface, with the idea that the private sector can use these algorithms, codes, and modules and design a suitable user-friendly interface.

Key Consumer Preference/Values – Nonenergy Benefits.(1) The following nonenergy characteristics were not considered in developing energy-output estimates:

- Improved indoor environmental quality, such as thermal comfort and ventilation adequacy
- Improved indoor air quality
- Fire safety
- Overall environmental sustainability (i.e., Green Buildings).

4.1.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. Working together with the Commercial Buildings R&D Project, this project has the following performance goals:

- By 2004, reduce heating and cooling loads by 30% in new construction and by 20% in existing units
- By 2010, reduce heating and cooling loads by 50% in new construction and by 30% in existing units.
- By 2020, reduce heating and cooling loads by 60% in new construction and 40% in existing units.

Technical Potential. Approximately 2 QBtu in 2005. The technical energy savings potential for this project includes all heating, cooling, and water-heating primary energy consumption (5.3 QBtu) for about 70% of the commercial building sector. Because the maximum performance goal for this program is a 60% reduction in these end uses, the technical potential is 5.3 QBtu * .60 * .70 = 2.2 QBtu(4).

Expected Market Uptake. The market penetration goal is to accelerate the penetration of high-performance building designs, such that 60% of new commercial and multifamily construction, and 20% of existing construction, incorporates the products supported by this project by 2020. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). PNNL assumes that this project accelerates the adoption of relevant energy-savings products, technologies, and designs by 10 years.

4.1.4 Sources

(1) FY 2002 Budget Request - *Data Bucket Report for Analysis Tools and Design Strategies Program* (internal BTS document).
(2) Interview with the project manager, Dru Crawley, August 22, 2001
(3) E-mail correspondence with project manager, Dru Crawley, June, 2003.
(4) Table 1.3.3, page 1-10 of 2003 Buildings Energy Databook.
(5) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

4.2 Appliances and Emerging Technologies R&D

4.2.1 Target Market

Project Description. This project helps manufacturers and utilities commercialize highly efficient appliances and equipment by providing the following assistance:

- Technology procurement to bring new technologies to market (late developmental work), which can bridge the gap between traditional R&D and mainstream deployment.
- Independent third-party evaluation and verification of highly efficient technologies using field studies and demonstrations increase market share of emerging technologies and Energy Star technologies with very low market penetration.
- R&D on appliances not covered by other projects but offering significant energy-savings potential.

Market Description: The market includes residential and commercial building technologies, with emphasis on appliances, water heating, lighting, and building equipment.

Size of Market: The market size depends on the selected equipment:

- **Heat Pump Water Heaters:** 13.6 million existing homes of the potential 44 million homes with electric resistance water heaters and about 40% of new homes. Limited, but initial market, for light commercial.
- **Rooftop Air Conditioners:** One of the most widely used technologies with greatest commercial space-conditioning energy use; more than a million tons sold in 1998.
- **Residential Can Lights:** An estimated 22 million incandescent can fixtures sold in 2001.
- **Reflector CFLs (R-lamps):** Nearly 125 million parabolic/reflector lamps sold to the residential market.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

4.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy output estimates:

- Reduced carbon emissions
- Economic benefits to private sector.
- Dehumidification provided by heat-pump water heater.
- Reduced lamp replacement frequency with R-CFLs and CFL cans.

4.2.3 Methodology and Calculations

Heat-Pump Water Heater

The purpose of this project is to expand the market for heat-pump water heaters. Field testing, data collection, workshops, and potential volume purchasing are elements of this project. The Appliances and Emerging Technologies project is assumed to lead to a more rapid commercialization of a moderately priced heat-pump water heater, first available in 2003.

The input file used for *Annual Energy Outlook 2001*(2) included several categories of heat-pump water heaters, two having installed costs of >$1,000. With the discount rates used in *Annual Energy Outlook 2001* for electric water heaters, only a very small number of the $1,025 units are predicted to be sold (no higher-costs unit). A more moderately priced heat-pump unit is assumed to become available in 2005, with a cost of $900 and an energy factor of 2.0. By 2015, the cost of this unit is assumed to fall to $800 and the energy factor to increase to 2.2.

The original *Annual Energy Outlook 2001* input file does not reflect the pending water heater standards that are scheduled to take effect in 2004. Two modifications were made to account for these standards (shown at the top of Table 9.1):

1. Technology No. 1 (see Table 9.1) was assumed to be unavailable after 2003 and therefore was dropped from the list of technologies available to consumers in the FY 2005 time horizon.

2. The efficiency for Technology No. 2 was changed to 0.89 with an unchanged cost (see revised characteristics under technology labeled No. 2a in **Table 6**).

Table 6. Key NEMS-PNNL[b] Inputs for Electric Water Heaters

Technology	Start Year	End Year	Energy Factor	Installed Cost	Type
1	1997	2003	0.86	$350	Resistance
2	1997	2003	0.88	$350	Resistance
2a	2003	2020	0.89	$350	Resistance
3	1997	2020	0.95	$575	Resistance
4	1997	2020	2.60	$1,025	Heat Pump*
5	1997	2020	2.00	$2,600	Heat Pump
6	1997	2020	0.90	$360	Resistance
7	2005	2020	0.96	$475	Resistance
8	2004	2009	2.47	$700	Heat Pump**
9	2015	2020	0.90	$400	Resistance
10	2015	2020	0.96	$425	Resistance
11	2006	2020	2.47	$650	Heat Pump**

* Inexplicably, the lower-cost unit is assumed to have a higher efficiency.
** Appliances and Emerging Technologies project.

The Appliances and Emerging Technologies project is assumed to lead to a more rapid commercialization of a moderately priced heat pump water heater, first available in 2003. However, the project's principal impact is to achieve a lower cost than the unit assumed to be introduced in 2005 in the *Annual Energy Outlook 2001* base case. As **Table 6** shows, the heat pump water heater units supported by emerging technologies are assumed initially to have energy efficiency rating of 2.47 and an installed cost of $700.[c] By 2006, further development will yield a unit with the same energy factor (2.47) at lower cost ($650).

One issue related to assessing impacts of this technology with the NEMS-PNNL model is the appropriate discount rate to use. The logit parameters in the NEMS-PNNL model related to the choice of electric water heaters are -0.0162 (Beta1) and -0.0195 (Beta2), implying a discount rate of about 83%.[d] At this discount rate, the high initial cost of the heat pump water heater, even with its much higher efficiency, discourages most consumers from choosing this technology. A more robust assessment of the project is obtained by assuming that the ongoing Energy Star project for water heaters provides impetus for increased market acceptance of the heat pump

[b] Any modification or alteration to the official EIA NEMS model must be called out as such; for PNNL's effort, the modified version used is referred to as NEMS-PNNL.
[c] The influence of emerging technologies research is assumed to reduce the unit from $900 (Annual Energy Outlook 2001 base case) to $700.
[d] Within NEMS-PNNL, the two modeling parameters determining the discount rate are labeled Beta1 and Beta2. Beta1 is used as a multiplicative factor with the initial cost of the appliance. Beta2 is used to multiply the annual energy cost. As a rough approximation, the ratio of Beta1/Beta2 can be interpreted as the consumer discount rate for the specific appliance.

water heater.[e] In this scenario, the changes in the discount rates assumed for Energy Star project are combined with the introduction of the (lower-cost) heat-pump water heater.

The *Annual Energy Outlook 2001* baseline parameters that determined the market share for electric water heaters are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.0162}{-0.0195} \approx discount\ rate = 83\%$$

With the support of the Appliances and Emerging Technologies and the Energy Star projects, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.0072}{-0.0195} \approx discount\ rate^{E-Star} = 37\%$$

As **Table 7** shows, the lower discount rates generate much higher penetrations of the heat pump water heater, ultimately reaching nearly 25% of sales by 2010. While Table 9.2 displays the shares for only new homes, the shares for the replacement market are similar.

Table 7. NEMS-PNNL Results for Heat Pump Water Heaters (national market shares[f] for new single-family homes)

Year	Market Share with *Annual Energy Outlook 2001* Discount Rate	Market Share with Adjusted NEMS-PNNL Discount Rates
2004	0.024	0.040
2005	0.012	0.031
2006	0.012	0.050
2007	0.012	0.077
2008	0.012	0.116
2010	0.028	0.239
2015	0.047	0.241
2020	0.048	0.243

[e] Market transformation projects, such as Energy Star, attempt to accelerate market penetration of existing high-efficiency technologies. From a modeling standpoint, these efforts translate into reducing the consumer's discount rate for these energy-efficient products. See the documentation specific to Energy Star project for more information.
[f] The market shares in this discussion pertain only to electric water heaters.

The project's energy savings were calculated as the difference between NEMS-PNNL model runs that do the following:

1. Include the heat pump water heaters assumed in the AEO base case.
2. Substitute the lower-cost units assumed to stem from the Emerging Technologies project.
3. Assume Energy Star influence on deploying technology such that discount rate is reduced for water heaters.[g]

In essence, the heat pump water heater savings were calculated as the difference between an Energy Star project with and without the units developed under the Appliances and Emerging Technologies project.

Market Introduction: 2003; PNNL assumed these projects would accelerate the introduction of these technologies into the marketplace by 10 years.

Performance Target: 2.47 energy factor.

Installed Cost: Initial installation cost of $700, decreasing to $650 in 2006.

Lifetime: 10 years.

Rooftop Air Conditioning

The intent of the rooftop air-conditioner project is to use competitive procurements of large numbers of units to stimulate the production of high-efficiency equipment. The immediate goal is to get high-efficiency equipment installed in buildings owned by the federal government and other state and local agencies. A long-term, key outcome of the project is to provide incentives for manufacturers to reduce the cost of this equipment to all potential and private sector buyers.

With this long-term goal in mind, PNNL adjusted the assumed costs of high efficiency roof top air conditioners in the NEMS-PNNL commercial model to reflect the principal influence of this project. In NEMS-PNNL, two air conditioners were specified in the rooftop category—a baseline unit (energy efficiency ratio of 8.5) and a high-efficiency unit (energy efficiency ratio of 11.6). No subgroups were distinguished by capacity (e.g., 65 to 135 kBtu/hr vs. 135 to 240 kBtu/hr).

For this analysis, the incremental cost was reduced by 40%, based on project goals. Given the proportion of the market assumed in the NEMS-PNNL to display high discount rates in the selection of equipment, this cost reduction yielded a 9% penetration of the high-efficiency unit in 2005. The penetration rate falls to 6% in 2010, possibly as a result of a greater efficiency in the baseline units and/or lower energy costs. By 2020, the proportion of the total stock using the high-efficiency unit is about 5%.

[g] In both runs, the adjustments to the discount rate (via the Beta1 coefficient) were the same as those used in evaluating the Energy Star project (within the Weatherization and Intergovernmental Program) for water heaters. The assumption of an ongoing Energy Star project raises the question of whether the Energy Star project should receive some of the credit for energy savings from this technology. No clear methodology exists for decomposing the benefits between applied R&D project and market conditioning activities. If such an attribution must be made for this process, 70% of the savings are proposed to be assigned to the Appliances and Emerging Technologies project and 30% to Energy Star.

Market Introduction: 2004; PNNL did not model any acceleration of market acceptance because the impact was determined to be negligible. Because the technology has only modest penetration (10%) by 2020 and only a few percent by 2010, assuming that this project accelerated market acceptance would not have a significant impact over the analysis period, therefore, no acceleration was assumed.

Performance Target: An efficiency increase from 10.3 to 11.0 energy efficiency ratio for 65 to 135 kBtu/hr and from 9.7 to 10.8 for 135 to 240 kBtu/hr.

Lifetime: 15 years.

Residential Can Lights

The intent of this project is to develop a recessed can light fixture that uses compact fluorescent lamps rather than incandescent.

Market Introduction: 2003; these projects were assumed to accelerate the introduction of these technologies into the marketplace by seven years.

Performance Target: Assumed efficacy of 37.5 lumens/watt[h]. Actual project requirements should be similar to other programs; here, efficacy is expected to improve by a factor of 2.5, while R-lamps are expecting an improvement factor of 3.33 and Energy Star CFLs are looking to an improvement factor of 3.42.

Installed Cost: Incremental cost above incandescent cans is $30/can in 2004 declining to $20/can by 2011.

Lifetime: 30 years.

R-Lamps

The intent of this project is to develop a floodlight or spotlight (lamps using reflector surfaces) that can utilize a screw-base compact fluorescent lamp rather than an incandescent lamp.

Market Introduction: 2004; these projects were assumed to accelerate the introduction of these technologies into the marketplace by five years.

Performance Target: Assumed efficacy of 50 lumen/watt[i]. Actual project requirements should be similar to Energy Star (within WIP), as **Table 8** shows.

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[h] Actual efficacy is lower than this value. The value of 37.5 assumes an existing technology value of 15 lumens/watt; actual incandescent can lights have efficacies significantly lower than this. However, BESET currently assume all incandescent lighting to have an efficacy of 15 lumens/watt. The proposed technology, which has the same lumen output as the current technology, is rated at 26W while the existing incandescent technology is rated at 65W. Hence 15 * 65 / 26 = 37.5.

[i] Actual efficacy is lower than this value. Weighting the Energy Star targets 58% for less than 20W and 42% for 20W or more (58% of incandescent lamps in homes have Wattages less than 75W and 42% of incandescent lamps in homes have Wattages 75W and greater[(1)]) yields an average lumens/watt of 36. The comparison incandescent lamp, EPACT 65W R-lamp, has approximately 700 lumens or 10.8 lumens/watt. Thus the proposed technology has an efficacy 3.33 times that of the incandescent lamp. However, because BESET currently assume all incandescent lighting to have an efficacy of 15 lumens/watt the actual 36 lumens/watt cannot and for the appropriate comparison 50 lumens/watt must be used (15 * 3.33 = 50 lumens/watt).

Table 8. Performance Targets for R-Lamps

Lamp Power (watts) and Configuration	Minimum Efficacy: Lumens/watt*
Reflector Lamp:	
Lamp power <20	33
Lamp power >=20	40
* Based on initial lumen date.	

Installed Cost: Initial cost is $7/compact fluorescent lamp reflector lamp; which represent an initial incremental cost of $5/unit in 2004, which declines to $1.50/unit by 2020.

Lifetime: 8,000 hours

4.2.4 Sources

(1) Estimated from http://enduse.lbl.gov/Info/LBNL-39102.pdf, p.19.
(2) Gordon, K.L., and M.R. Ledbetter. 2001. *Technology Procurement Screening Study*. Pacific Northwest National Laboratory, Richland, Washington.
(3) The Freedonia Group, Inc. 1999. *Lamps in the United States to 2003*. Cleveland, Ohio. (See the following sections: "Introduction," "Executive Summary," "Market Environment," "Supply and Demand," "Incandescent Lamps," "Electrical Discharge," and "Lamp Markets.")

4.3 Envelope Research and Development

4.3.1 Target Market

Project Description. The project's objective is to promote the research, development, and deployment of energy-efficient windows. Because the fenestration field is less suited to national standards and has a growing international market, significant investments are needed to establish a technical basis for performance standards recognized for scientific excellence. On this basis, the project helps develop the credible rating, certification projects, and design tools to develop and apply efficient windows. The project also conducts R&D on high-performance windows, including electrochromic technology and durable spectrally selective glazing.

The project's specific long-term goals are as follows:

- National: Change windows from net energy losers to net energy providers across the United States.
- Industry: Strengthen market position of U.S. industry in global markets.
- Owners: Provide cost-effective savings with comfort, productivity, and amenity.

Market Description[1]: The market includes new and existing commercial and residential buildings in all climate zones.

Size of Market[1]: 500 million square feet of windows for commercial buildings and approximately 55 million manufactured units sold each year for residential and light commercial.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

4.3.2 Key Factors in Shaping Market Adoption of EERE Technologies

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy output estimates:

- Reduced utility and building peak loads
- Reduced HVAC Requirements and first costs
- Improved indoor comfort and aesthetics.

4.3.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Electrochromic Windows

Electrochromic multilayer windows are windows that can be darkened by applying a low voltage. When the voltage is removed, the window lightens. This project develops commercially viable advanced electrochromic windows using competing producers. With a focus on electrochromic research, the project's objective is to reward the marketplace for industry's investments in researching, developing, and deploying energy-efficient windows.

Market Introduction: 2010; This project was assumed to accelerate the introduction of this technology into the marketplace by 10 years.

Performance Parameters: Performance parameters for Electrochromic Windows are presented in **Table 9**.

Table 9. Performance Parameters for Electrochromic Windows

Parameter	Value	Units
Maximum Shading Coefficient	0.4 (heating)	Dimensionless
Minimum Shading Coefficient	0.1 (cooling)	Dimensionless
U-value	0.25	Btu/h • ft^2• ^oF
Lighting Reduction	30	% of lighting energy

Performance Target. Performance characteristics vary by building type and climate zone. The estimated savings per building were determined by simulating residential buildings in all climate zones. National impacts were determined using BEAMS (see **Table 10**).

Table 10. Performance Targets for Electrochromic Windows

	New Buildings		Existing Buildings	
	HEAT		HEAT	
	North	South	North	South
Assembly	8.01%	6.53%	9.51%	6.96%
Education	4.97%	-1.25%	5.37%	2.48%
Food Sales	-71.9%	-94.83%	-35.01%	-67.56%
Food Services	.27%	46.05%	6.97%	8.78%
Health Care	81.33%	93.42%	79.47%	67.56%
Lodging	16.31%	71.14%	19.00%	34.94%
Office-Large	47.78%	73.28%	41.38%	51.71%
Office-Small	17.71%	40.94%	18.28%	28.28%
Merc/Service	-52.26%	-84.53%	-31.01%	-51.24%
Warehouse	-71.9%	-40.11%	-10.89%	-12.7%
Other	-20.91%	-94.83%	-5.00%	-19.94%

	New Buildings		Existing Buildings	
	COOL		COOL	
	North	South	North	South
Assembly	34.78%	28.50%	34.99%	28.72%
Education	38.54%	32.24%	38.25%	32.47%
Food Sales	28.43%	22.85%	28.64%	23.69%
Food Services	26.43%	21.51%	25.63%	21.71%
Health Care	29.40%	21.01%	30.26%	22.34%
Lodging	37.39%	30.80%	38.00%	31.61%
Office-Large	40.69%	39.64%	39.82%	39.50%
Office-Small	34.74%	32.27%	34.15%	32.61%
Merc/Service	41.46%	35.31%	41.70%	35.61%
Warehouse	94.90%	58.18%	79.65%	43.26%
Other	61.43%	52.76%	63.26%	51.24%

Installed Cost:—Incremental Cost Over Low-e Double-Pane Windows

2010: \$50.00/ft^2
2015: \$20.00/ft^2
2030: \$5.00/ft^2

Lifetime: 20 years.

Expected Market Uptake. The goal is to obtain 20% of window sales in new buildings and 17% in existing buildings by 2020. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The "Accelerated" penetration curve represents the percent of electrochromic window sales with the DOE project; the "Net" penetration curve represents the percent of sales attributable to DOE, as PNNL assumed that the DOE project would accelerate market acceptance by 10 years. See penetration curves in **Figures 1 and 2**.

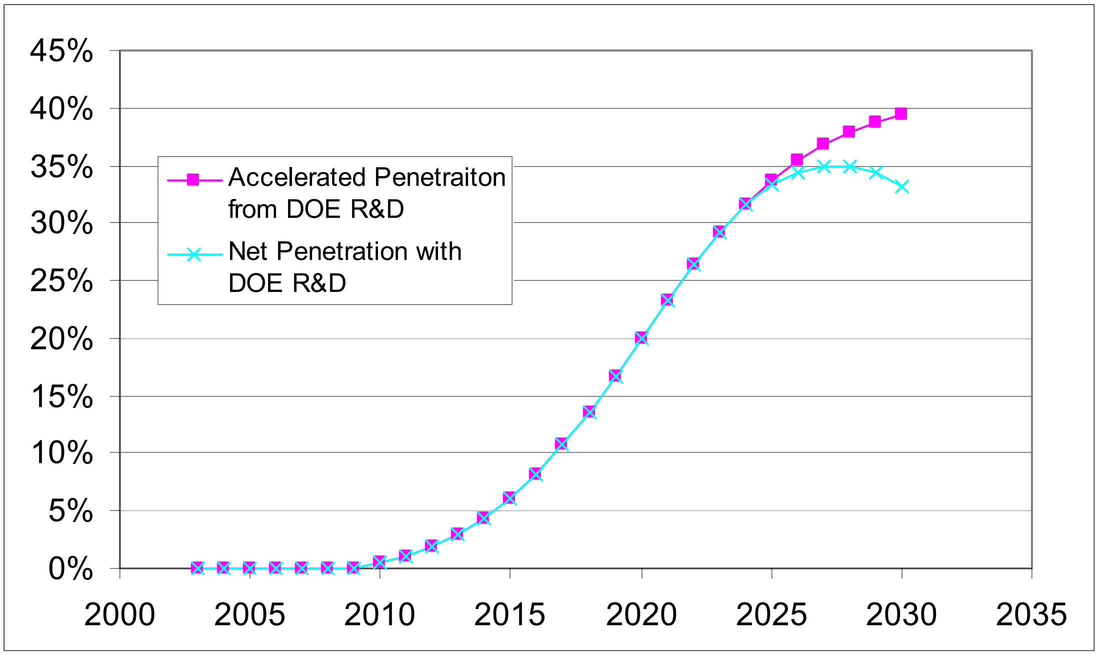

Figure 1. Market Penetration of Electrochromic Windows in New Buildings

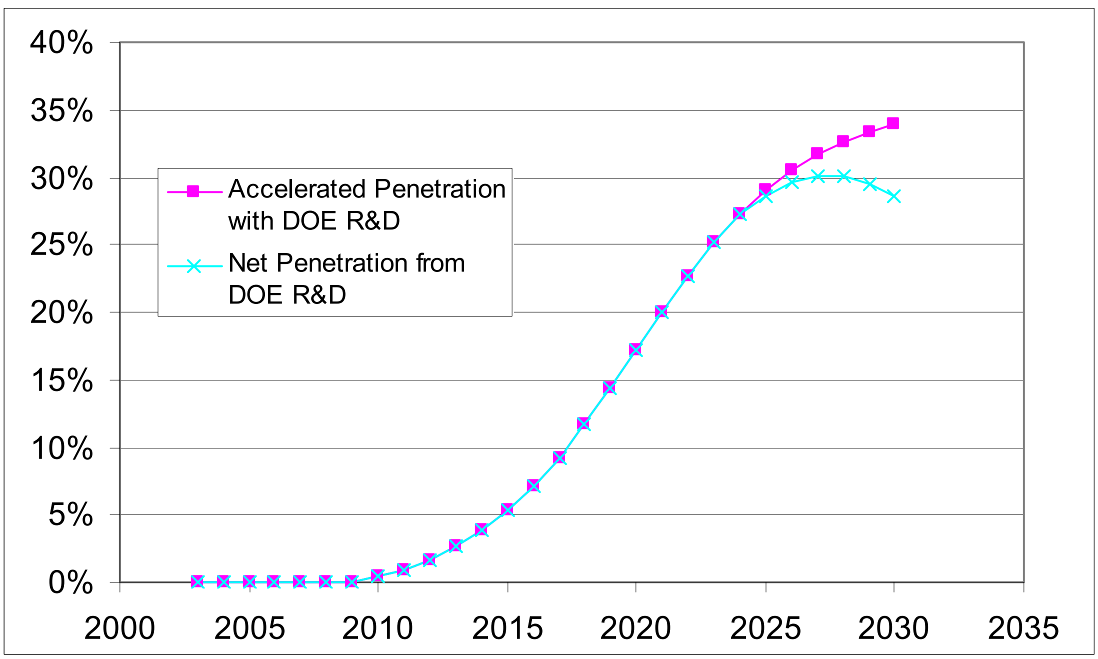

Figure 2. Market Penetration of Electrochromic Windows for Existing Buildings

Superwindows

The project is developing commercially viable advanced technologies from competing producers and providing research support to Energy Star and Efficient Window Collaborative projects. One project objective is to double the average energy efficiency of windows sold and establish universal National Fenestration Rating Council ratings based on credible International Standards Organization standards.

Technical Characteristics.
Market Introduction: 2007; PNNL assumed that this project would accelerate the introduction of this technology into the marketplace by 10 years.

Performance Parameters: Two superwindow technologies were used: northern superwindows in heating-dominated climates (heating-degree days >4500) and southern superwindows in cooling dominated climates (heating-degree days <4500) (see **Table 11**).

Table 11. Performance Parameters for Superwindows

Window	Parameter	Value	Units
Northern Superwindow	Shading Coefficient	0.7 (heating season) 0.3 (cooling season)	Dimensionless
	U-value	0.1	Btu/h • ft^2 • ^oF
Southern Superwindow	Shading Coefficient	0.15 (all seasons)	Dimensionless
	U-value	0.2	Btu/h • ft^2 • ^oF

Performance Target: Performance characteristics vary by building type and climate zone. The estimated savings per building were determined by simulating residential buildings in all climate zones. National impacts were determined using BEAMS (see **Table 12**).

Table 12. Performance Targets for Superwindows

	New Buildings		Existing Buildings	
	HEAT		HEAT	
	North	South	North	South
Single-Family	38.76%	-63.79%	27.97	-10.66
Multi-Family	90.76%	69.58%	73.93	22.05
Mobile Home	21.42%	-18.24%	20.19	-5.36
	COOL		COOL	
Single-Family	8.68%	27.25%	10.62	25.58
Multi-Family	-5.97%	23.79%	-.29	25.05
Mobile Home	15.09%	29.05%	15.03	26.20

Installed Cost:—Incremental Cost Over Low-e Double-Pane Windows

2007: $6.00/ft^2
2020: $4.00/ft^2
2030: $3.00/ft^2

Lifetime: 30 years

Expected Market Uptake. The goal is to obtain 65% of window sales in new buildings and 33% in existing buildings by 2020. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The "Accelerated" penetration curve represents the percent of superwindow sales with the DOE project; the "Net" penetration curve represents the percent of sales attributable to DOE, as

PNNL assumed that the DOE project would accelerate market acceptance by 10 years. See penetration curves in **Figures 3 and 4**.

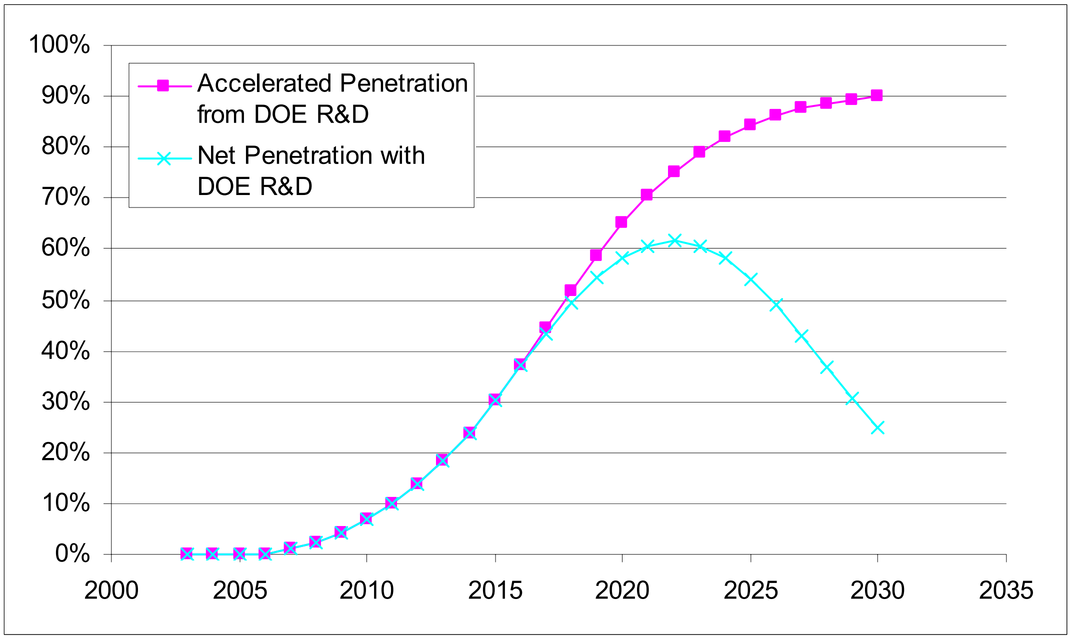

Figure 3. Market Penetration of Superwindows in New Buildings

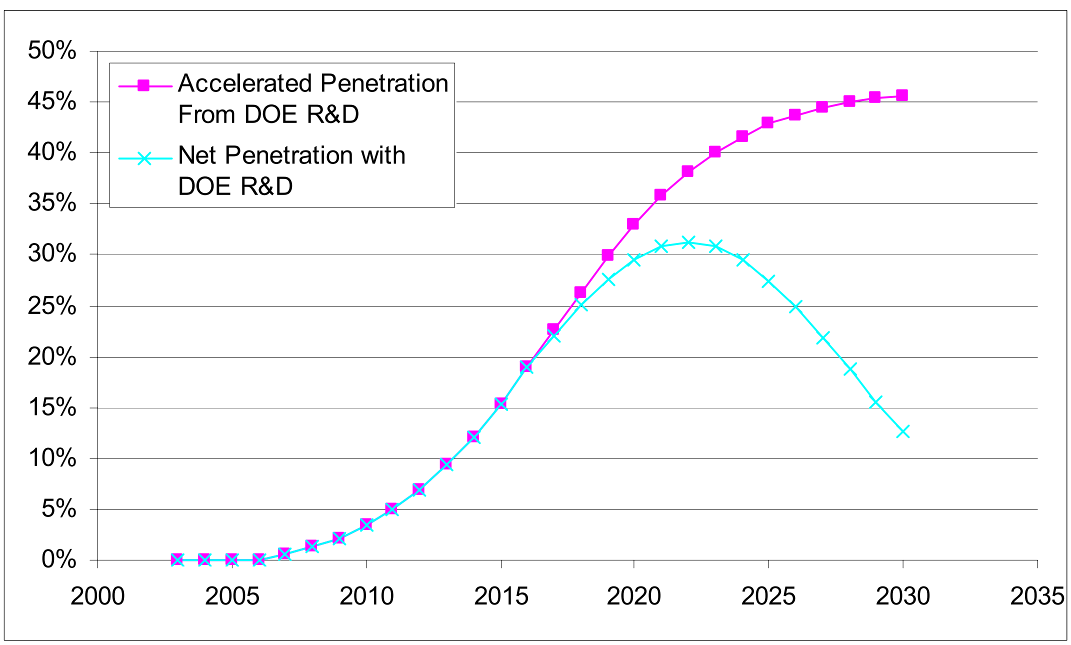

Figure 4. Market Penetration of Superwindows for Existing Buildings

Low-Emissivity Glass Acceptance

Low-e windows have at least one surface coated with a thin, nearly invisible, metal oxide or semiconductor film that reduces the heat transfer through windows. The conventional windows that they replace have no coating. This is a new program for FY05. The purpose of the program is to increase the penetration of low-e glass from 40% in the residential market and 10% in the commercial market to 100% in both markets by 2020. Two programs, Low-e Market Acceptance (BT) and Energy Star Windows (Office of Weatherization and Intergovernmental Programs), form the joint means to achieving the low-e penetration goal; hence, the savings will be split equally. The performance of the low-e glass is as described for the Electrochromic and Super Windows baseline.

Market Introduction: The technology is commercially available. PNNL assumed that this project would accelerate the penetration in the marketplace by 10 years.

Methodology and Calculations

Technical Characteristics.
Performance Parameters: Performance parameters are listed in **Table 13**.

Table 13. Performance Parameters for Low-e Windows

Parameter	Value	Units
Shading Coefficient	0.52	Dimensionless
U-value	0.357	Btu/h • ft^2 • ^oF

- **Performance Target:** Performance characteristics vary by building type and climate zone. The estimated savings per building were determined by simulating residential buildings in all climate zones. National impacts were determined using BEAMS (see **Table 14**).

Installed Cost:—Incremental Cost Over Conventional Double-Pane Windows
- 2005: $1.00/$ft^2$
- 2010: $0.50/$ft^2$
- 2015: $0.00/$ft^2$

Expected Market Uptake. The purpose of the program is to increase the penetration of low-e glass from 40% in the residential market and 10% in the commercial market to 100% in both markets by 2020. Both programs, Low-e Market Acceptance and Energy Star Windows (Office of Weatherization and Intergovernmental Programs), form the joint means to achieving the low-e penetration goal – the savings are to be split equally. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The "Accelerated" penetration curve represents the percent of superwindow sales with the DOE project; the "Net" penetration curve represents the percent of sales attributable to DOE, as PNNL assumed that the DOE project would accelerate market acceptance by 10 years. The penetration rates are shown in **Figures 5 and 6**. For Low-e Market Acceptance/Energy Star Windows, PNNL assumed that these projects would accelerate the acceptance of this technology in the marketplace by 10 years.

Table 14. Performance Targets for Low-e Windows

New Buildings			Existing Buildings	
	Heat		Btu/h • ft^2 • ^{o}FHeat	
	North	South	North	South
SingleFamily	39.73%	66.19%	28.22%	42.54%
MultiFamily	75.26%	94.44%	63.73%	84.21%
MobileHome	44.99%	53.89%	34.16%	39.30%
Assembly	44.88%	76.06%	38.32%	64.07%
Education	41.27%	73.62%	45.36%	66.11%
Food Sales	64.06%	91.69%	59.00%	76.73%
Food Service	66.17%	90.08%	56.17%	80.10%
Health Care	97.69%	99.81%	91.42%	98.22%
Lodging	63.34%	95.42%	55.83%	88.91%
Office-Large	65.00%	85.55%	59.44%	82.17%
Office-Small	50.17%	73.83%	43.72%	72.34%
Merc/Service	57.53%	80.16%	58.11%	75.68%
Warehouse	53.33%	63.84%	14.82%	9.86%
Other	55.83%	86.76%	44.19%	59.20%

New Buildings			Existing Buildings	
	Cool		Cool	
	North	South	North	South
SingleFamily	13.95%	16.59%	16.30%	17.38%
MultiFamily	1.92%	9.23%	7.35%	11.80%
MobileHome	22.31%	23.04%	19.26%	19.68%
Assembly	-11.69%	-8.47%	-4.85%	-4.18%
Education	-23.64%	-15.70%	-8.81%	-4.87%
Food Sales	-13.76%	-11.35%	-11.59%	-6.65%
Food Service	-15.38%	-10.65%	-8.14%	-6.10%
Health Care	-21.81%	-12.28%	-19.93%	-13.88%
Lodging	-38.61%	-29.58%	-18.52%	-19.56%
Office-Large	-40.67%	-31.12%	-33.71%	-27.50%
Office-Small	-25.43%	-23.59%	-7.03%	-10.92%
Merc/Service	-24.41%	-17.66%	-17.90%	-10.77%
Warehouse	63.97%	21.01%	47.73%	2.10%

	New Buildings		Existing Buildings	
	Heat		Heat	
	North	South	North	South
Single Family	39.73%	66.19%	28.22%	42.54%
Multi Family	75.26%	94.44%	63.73%	84.21%
Mobile Home	44.99%	53.89%	34.16%	39.30%
Assembly	44.88%	76.06%	38.32%	64.07%
Education	41.27%	73.62%	45.36%	66.11%
Food Sales	64.06%	91.69%	59.00%	76.73%
Food Service	66.17%	90.08%	56.17%	80.10%

Health Care	97.69%	99.81%	91.42%	98.22%
Lodging	63.34%	95.42%	55.83%	88.91%
Office-Large	65.00%	85.55%	59.44%	82.17%
Office-Small	50.17%	73.83%	43.72%	72.34%
Merc/Service	57.53%	80.16%	58.11%	75.68%
Warehouse	53.33%	63.84%	14.82%	9.86%
Other	55.83%	86.76%	44.19%	59.20%

	New Buildings		Existing Buildings	
	Cool		Cool	
	North	South	North	South
Single Family	13.95%	16.59%	16.30%	17.38%
Multi Family	1.92%	9.23%	7.35%	11.80%
Mobile Home	22.31%	23.04%	19.26%	19.68%
Assembly	-11.69%	-8.47%	-4.85%	-4.18%
Education	-23.64%	-15.70%	-8.81%	-4.87%
Food Sales	-13.76%	-11.35%	-11.59%	-6.65%
Food Service	-15.38%	-10.65%	-8.14%	-6.10%
Health Care	-21.81%	-12.28%	-19.93%	-13.88%
Lodging	-38.61%	-29.58%	-18.52%	-19.56%
Office-Large	-40.67%	-31.12%	-33.71%	-27.50%
Office-Small	-25.43%	-23.59%	-7.03%	-10.92%
Merc/Service	-24.41%	-17.66%	-17.90%	-10.77%
Warehouse	63.97%	21.01%	47.73%	2.10%

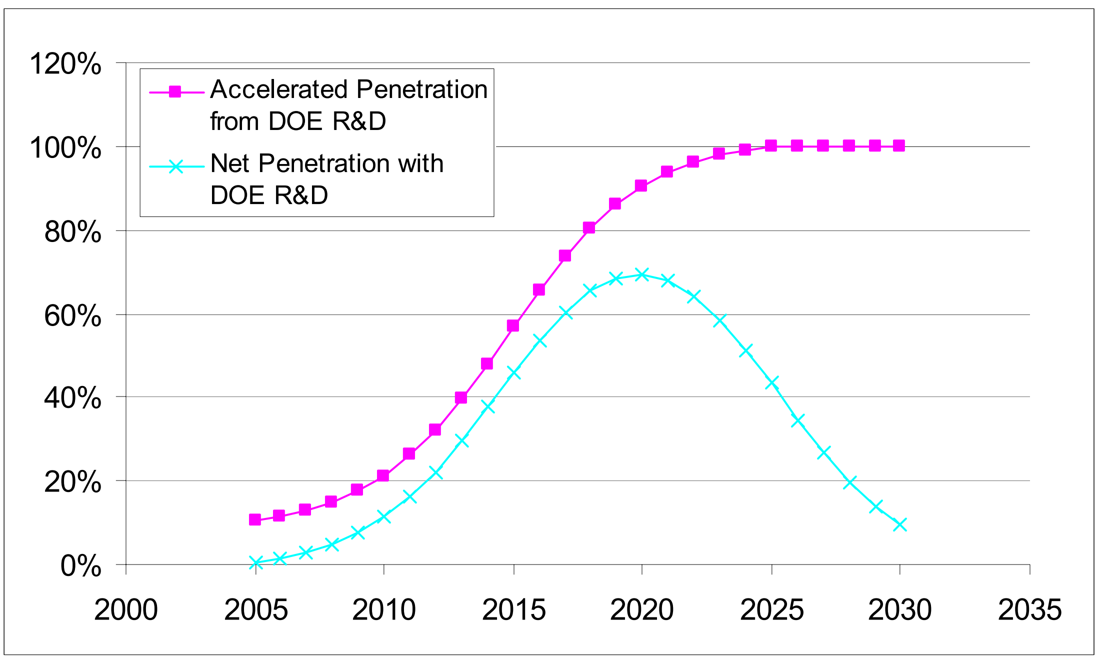

Figure 5. Market Penetration of Low-e Windows in Commercial Buildings

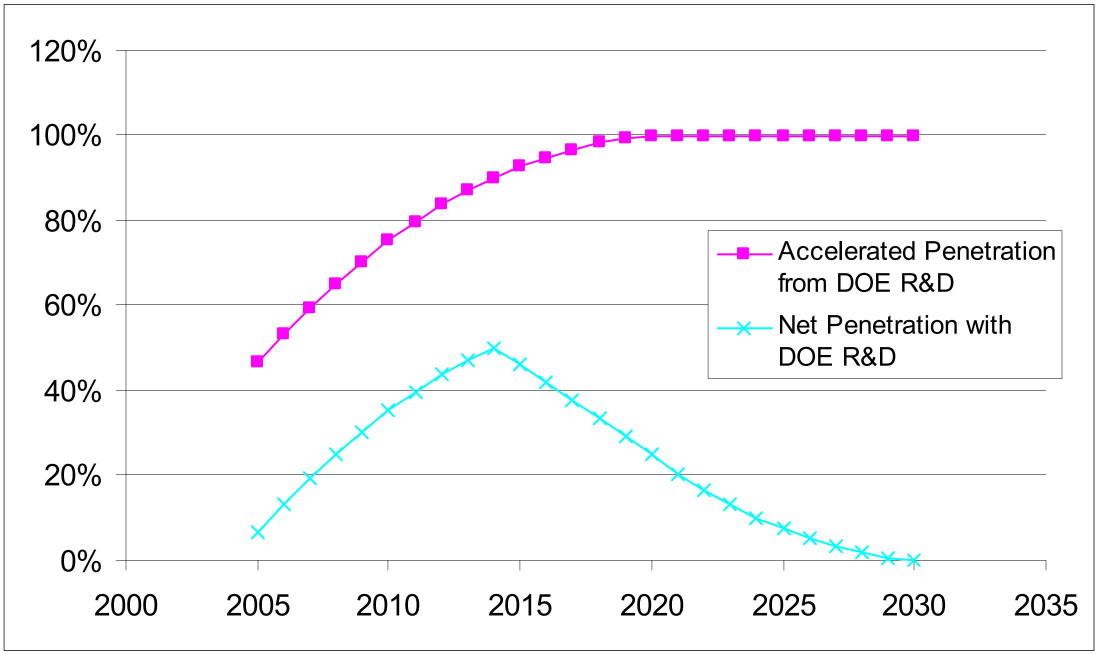

Figure 6. Market Penetration of Low-E Windows in Residential Buildings

4.3.4 Sources

(1) *FY 2002 Budget Request - Data Bucket Report for Building Envelope: Windows Program* (internal BT document).

(2) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

4.4 Lighting Research and Development

4.4.1 Lighting Controls

4.4.1.1 Target Market

Project Description. The Lighting R&D project develops and accelerates the introduction of advanced lighting technologies.

Market Description: The market includes all commercial buildings, with some technologies being introduced into residential buildings.

Size of Market: Lighting consumes 26% (3.9 quad) of the primary energy used in commercial buildings, which had a building stock of about 69 billion sq ft in 2000[(1)].

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

4.4.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a four-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $4).

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy output estimates:

- Develops U.S. leadership in lighting technology
- Reduces pollution and contributes to U.S. climate-change goals
- Improves U.S. productivity from better lighting in work environments
- Responds to an industry-initiated collaborative.

4.4.1.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. Various field studies(2) have shown a very large energy savings potential for lighting controls, primarily using occupancy and daylighting controls. These studies have shown that aggressively implementing controls can save 20% to 40% of lighting energy use. BT supports the development of more advanced systems—through both research and field testing—that will further reduce energy used for lighting in commercial buildings. BT support of research to evaluate the interrelationship between human vision and efficient light use will also contribute to future energy savings.

For FY 2005, the impact of the BT activities in lighting controls and efficient lighting practices was assumed to yield an incremental 5% reduction in lighting energy use compared with current practice. (By *incremental*, the BT activities are assumed to lead to further savings over and above the control technologies that the private sector offers now and are likely to offer.)

Expected Market Uptake. PNNL assumed that up to 60% of new commercial buildings could incorporate these technologies and that 20% of the existing stock could be retrofitted with these systems by 2020. A time profile of penetration rates was based on the historical pattern of market penetration observed for electronic ballasts. An S-shaped penetration curve was fit to historical market shares for electronic ballasts and then applied to project future adoption of advanced lighting distribution systems and controls. (This curve indicated that nearly 50% of the ultimate market penetration was achieved after nine years).

4.4.1.4 Sources

(1) *Annual Energy Outlook 2002*. 2002. Energy Information Administration, Washington, D.C.
(2) See http://eande.lbl.gov/btp/450gg/publications.html and www.cmpco.com/services/pubs/lightingfacts/controls.html

4.4.2 Solid-State Lighting

4.4.2.1 Target Market

Project Description. The Solid-State Lighting activity develops and accelerates the introduction of solid-state lighting and seeks to achieve the following for lighting:

- Significantly greater efficacy than conventional sources, such as T8 fluorescents
- Easy integration into building systems of the future
- Ability to provide the appropriate color and intensity for any application
- Ability to last 20,000 to 100,000 hours
- Ability to readily supplement natural sunlight.

Market Description: The market includes all commercial buildings, with some technologies being introduced into residential buildings.

Size of Market[(4)]: Lighting consumes 26% (3.9 QBtu) of the primary energy used in commercial buildings, which had building stock of about 69 billion ft^2 in 2000.[j]

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

4.4.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered in developing energy output estimates:

- Helps maintain U.S. semiconductor leadership
- Develops U.S. leadership in lighting technology
- Reduces pollution and contributes to U.S. climate-change goals
- Improves U.S. productivity from better lighting in work environments
- Responds to industry-initiated collaborative.

4.4.2.3 Methodology and Calculations

Technical Characteristics. Key assumptions concerning the likely dates of introduction and the expected efficacies were influenced by two sources: 1) “The Case for a National Research Program on Semiconductor Lighting,”[(2)] a white paper prepared by Hewlett-Packard and Sandia National Laboratories and presented in late 1999 at an industry forum; and 2) a more extended study[(3)] by A.D. Little for BT in early 2001; the study used some of the basic assumptions in the white paper[(2)] in developing some scenarios related to solid-state lighting.

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[j] According to a recent report completed for DOE by Navigant Consulting (“U.S. Lighting Market Characterization, Volume I: National Lighting Inventory and Energy Consumption Estimate,” September 2002), the amount of energy used for lighting is greater than EIA has traditionally estimated. The report estimates that commercial lighting requires 4.2 QBtu and residential lighting requires 2.2 QBtu. This report, however, was distributed after the FY04 GPRA estimates were prepared, so PNNL’s estimates are based on EIA’s estimates.

The most recent work pertaining to the goals of the Next Generation Lighting Initiative, however, is a series of cost and performance projections prepared by Lincoln Technical Services (LTS) in the fall of 2002.[k] For the FY05 GPRA effort, the LTS estimates were used exclusively to drive the input assumptions.

The LTS estimates were predicated on a substantial ramp up of funding for this area of research by DOE. Within about five years, the funding for this activity was expected to increase to about $50 million per year, remaining at that level for a decade or longer.

The energy savings path essentially assumes that the technology would not be introduced without DOE support. In part, this assumption stems from the time horizon of the *Annual Energy Outlook 2002* version of NEMS that does not extend beyond 2020.

NEMS characterizes each lighting technology by source efficacy level (lumens/watt), capital cost ($/1000 lumens or $/kLumen), and annual maintenance cost of lamps. For new technologies, the capital costs can be reduced along a logistic-shaped curve. The NEMS model divides the commercial lighting market into four major groups: 1) incandescent CFL (point source), 2) 4-foot fluorescent, 3) 8-foot fluorescent, and 4) high-intensity point source (outdoor lighting). Solid-state lighting was assumed to penetrate the first three market groupings.

Given the cost assumptions, the NEMS model chooses among these technologies for each building type in each census division. For each group, the market is assumed to be further segmented, with each segment characterized by a different discount rate in its decision-making criteria. Within each segment, a lighting technology is selected based on minimum annualized cost.

Table 15 summarizes the cost inputs for some of the key lighting technologies used in NEMS-PNNL for FY 2005. The FY 2005 estimates were based on the efficacy of solid-state lighting reaching 160 lumens/watt in 2010, 180 lumens/watt by 2015, and 208 lumens/ watt by 2018.

4.4.2.4 Sources

(1) FY 2002 Budget Request – *Data Bucket Report for Lighting R&D Program* (internal BT document).
(2) Haitz, R., and F. Kish (Hewlitt-Packard Co) and J. Tsao and J. Nelson (Sandia National Laboratories). 1997. "Case for a National Research Program on Semiconductor Lighting," White paper presented at the 1999 Optoelectronics Industry Development Association forum in Washington D.C., October 6, 1999.
(3) A.D. Little. 2001. *Energy Savings Potential of Solid State Lighting in General Lighting Applications*. Prepared for DOE's Office of Building Technology, State and Community Programs by A.D. Little, Cambridge, Massachusetts.
(4) *Annual Energy Outlook 2002*. 2002. Energy Information Administration, Washington, D.C.

[k] Spreadsheet named Dave.data1.xls transmitted by Michael Scholand of Navigant Consulting, Inc. on October 30, 2002.

Table 15. Solid-State Lighting Cost and Efficiency Assumptions – FY 2005 GPRA

	Efficacy (Lumen/ watt)	Light Source Cost ($/kLumen) (2010)	Light Source Cost ($/kLumen) (2017)	Light Source Cost ($/kLumen) (2019)	Light Source Cost ($/kLumen) (2020)	Ann. Oper. Cost ($/yr)
Incandescent / CFL						
Incandescent A19	15	0.25	0.25	0.25	0.25	6.50
CFL (pin-base, 20 watts)	60	4.89	4.70	4.52	4.34	1.75
CFL (integral, 20 watts)	60	8.00	7.69	7.39	7.10	1.75
Solid state (2017 intro)	160	NA	12.00	12.00	12.00	0.87
Solid state (2019 intro)	164	NA	NA	11.20	11.20	0.87
4-foot Fluorescent						
Halogen reflector lamp	14	5.84	5.84	5.84	5.84	15.77
F32T8 Electronic	80	1.01	0.97	0.93	0.90	2.80
Solid state (2017 intro)	160	NA	12.00	12.00	12.00	2.53
Solid state (2019 intro)	164	NA	NA	11.20	11.20	0.87
8-foot Fluorescent						
F96T12 - Electronic ES	61	3.01	2.89	2.77	2.66	5.25
F96T12 - Electronic HO	52	1.88	1.81	1.74	1.67	9.64
Solid state (2017 intro)	160	NA	12.00	12.00	12.00	2.50
Solid state (2019 intro)	164	NA	NA	11.20	11.20	0.87
NA = Not applicable.						

4.5 Space Conditioning and Refrigeration R&D

4.5.1 General Target Market

Project Description. This project develops and promotes the use of commercial food display and storage technologies that use less energy and less refrigerant. Water-heating activities are centered on developing low-cost, high-reliability heat pump water heater concepts. The project's HVAC delivery (e.g., duct work) technologies are intended to reduce the energy losses incurred in transferring heating or cooling from the conditioning units (e.g., heat pump, furnace, and air conditioner) to the conditioned space. The refrigerant pressure charge meter and coefficient of performance (COP) meter enables early warning of poor operation of HVAC equipment to keep installed equipment operating at design efficiencies during the service life.

Market Description:(1) The market includes commercial refrigeration, a broad classification of building equipment that collectively consumes about one quad of U.S. energy annually.(2) Supermarkets consume about one-third of the energy used in commercial refrigeration. Residential applications include air conditioners, heat pumps, heat-pump water heaters, and thermal distribution systems associated with forced air systems.

Size of Market: (1) Commercial refrigeration markets include about 30,000 large supermarkets and 100,000 convenience stores. Other markets include hospitals, large institutional buildings, and restaurants. Residential markets include new, single-family, and existing homes.

Baseline Technology Improvements. For this analysis, PNNL did not suggest any changes in technology improvements, apart from the EIA baseline.

4.5.2 Residential HVAC Distribution Systems

4.5.2.1 Target Market

Project Description. The Zero Cubic Feet per Meter (CFM) Loss Duct have the following characteristics:

- Shop-fabricated round ducts that are ready for installation. Installation consists of inflation of the double walled duct followed by connection to registers and supply. Then space between duct walls is filled with moisture resistant spray foam insulation (R-8) which resists vapor condensation on cold surfaces during cooling.
- Applicable to residential and light commercial (e.g., small commercial buildings where the chief energy efficiency issue regarding ventilation is thermal loss from the ducts).
- Applicable to new construction and retrofit.
- Applicable only to ducts in crawl space and attic.
- Result is CFM duct leakage approaching 0 CFM.
- Project includes market deployment element, specifically development of materials (CDs and brochures) designed to inform the home owner about the advantages of the technology

Market Description. The seasonal heating distribution includes conduction through duct walls, as well as air leakage through duct system holes and joints for ducts located in unconditioned spaces. The seasonal heating distribution efficiency of typical current ducts is about 56% and 72% for good conventionally designed ducts with R-4 duct insulation.[l] For this analysis, PNNL assumed that existing homes have "typical ducts" and new homes would have "good conventionally designed ducts." The seasonal cooling distribution efficiency of typical current ducts is about 75% and 87% for good conventionally designed ducts with R-4 duct insulation.[m]

[l] Brookhaven National Laboratory. 2001. *Better Duct Systems for Home Heating and Cooling*. BNL-68167, Vol. 4, Upton, New York, p.10.
[m] ibid.

Given the limited use of ducts in unconditioned spaces in light commercial buildings,[n] this analysis was limited to residential applications. Compensating for this is the assumption that all residential duct work is in unconditioned spaces.

4.5.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. This product is expected to have the following characteristics:

- Cost is less than current ductwork for new homes.
- Cost is $1,000 for materials, plus one person-day labor ($250) for installation in retrofit (include disconnection and moving aside of existing duct work)

4.5.2.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. Zero CFM Loss Ducts (a.k.a. push button ducts) have the following characteristics:

- Shop fabricated round ducts that are ready for installation. Installation consists of inflation of the double-walled duct followed by connection to registers and supply. Then space between duct walls is filled with moisture-resistant spray foam insulation (R-8)—resists vapor and condensate on cold surfaces during cooling.
- Applicable to residential and light commercial.
- Applicable to new construction and retrofit.
- Applicable only to ducts in crawl space and attic.
- Result is ~0 CFM duct leakage.
- Project is going to include development of materials (CDs and brochures) designed to "sell" the home owner on the concept

The estimated improvement in heating and cooling system seasonal distribution efficiency is shown in **Table 16**.

Table 16. Assumed Reductions in Energy Use for Residential HVAC Distribution Systems

System	*Heating*	*Cooling*
Current Technology Existing Buildings	56	75
Current Technology New Buildings	72	87
R-8 Ducts with 5% Leakage[o]	80	90
BT Technology[p]	87	95

[n] Light commercial, a.k.a. small commercial are buildings where the chief energy efficiency issue regarding ventilation is thermal loss from the ducts whereas for large commercial the chief ventilation energy efficiency issue is fan power. (Andrews, John W, and Mark P Modera. July 1991. *Energy Savings Potential for Advanced Thermal Distribution Technology in Residential and Small Commercial Buildings.*)

[o] ibid.

Expected Market Uptake. This product is intended to be used in both new construction and retrofit applications. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The “Accelerated” penetration curve represents the percent of superwindow sales with the DOE project; the “Net” penetration curve represents the percent of sales attributable to DOE, as PNNL assumed that the DOE project would accelerate market acceptance by 10 years.

- Penetration (fraction of sales in ducted residences) for new buildings is 2008 introduction, 50% in 2020, and 80% in 2030. With about 90% of new residential construction using ducts,[q] the penetration across all new residential construction (percentage of residential buildings constructed that year) is 45% (50% * 90%) in 2020, and 72% (80% * 90%) in 2030 (**Figure 7**).
- Penetration (fraction of sales) for existing buildings is 2008 introduction, 25% in 2020, and 40% in 2030, assuming this only occurs when making an HVAC equipment change (i.e., once every 20 years). With 50% of existing homes having ducts[r], and only 1/20 of the homes receiving new HVAC equipment each year, the penetration across all existing residential building (percentage of buildings receiving the technology that year) is 0.625% (25% * 50% * 1/20) in 2020, and 1.25% (50% * 50% * 1/20) in 2030 (**Figure 8**).

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[p] Heat system performance improves from 56% to 72% (a 16 percentage point improvement) by reducing typical duct leakage loss of 17% to 5%; hence, reducing from 5% to 0% can be expected to save an addition 6.66 (5/12 * 16) percentage points. Cooling system performance improves from 75% to 87% (a 12 percentage point improvement) by reducing typical duct leakage loss of 17% to 5%; hence, reducing from 5% to 0% can be expected to save an addition 5 (5/12 * 12) percentage points. These savings are added to the benefit of going from the current designs shown in the table to a design with 5% leakage and R-8 insulation.

[q] Brookhaven National Laboratory. 2001. Better Duct Systems for Home Heating and Cooling. BNL-68167, Vol. 3, Upton, New York, p.1.

[r] ibid.

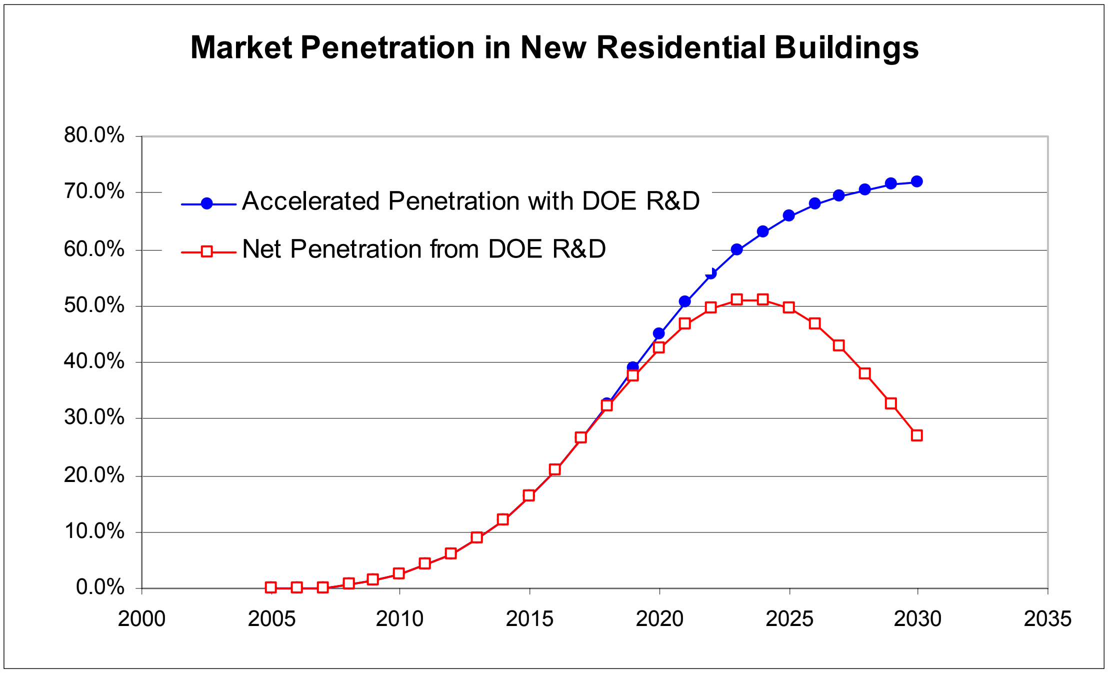

Figure 7. Market Penetration of HVAC Distribution in New Residential

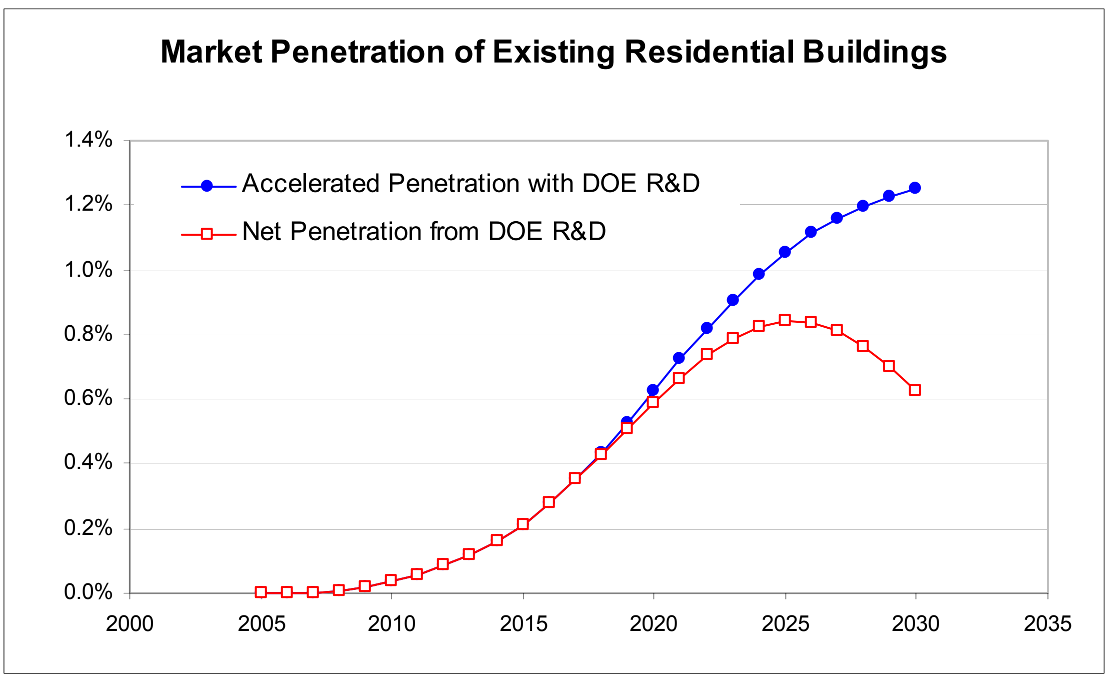

Figure 8. Market Penetration of HVAC Distribution in Existing Residential

4.5.3 Advanced Electric Heat Pump Water Heater

4.5.3.1 Target Market

Project Description. The goal of this technology is to increase the efficiency of residential and commercial electric water heating equipment and reduce peak energy use. The purpose of this project is to improve the cost effectiveness of heat pump water heaters mainly through lower capital costs.

Market Description: Residential and commercial.

Market Introduction: 2005; this project was assumed to accelerate the introduction of this technology into the marketplace by 10 years.

Performance Target: 1.8 energy factor.

4.5.3.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price.

- Cost of Conventional Technology: $350
- Cost of BT Technology: $1025
- Incremental Cost: $675/unit.

4.5.4 Commercial Refrigeration

4.5.4.1 Target Market

Project Description. DOE is working to improve the efficiency of refrigerated display cases and developing methods of recovering reject heat for space conditioning. This project was modeled as an advanced supermarket refrigeration system that would target heating, cooling, and refrigeration end-use loads in the commercial food sales sector. The heating and cooling reductions occur because commercial refrigeration equipment draws a large amount of heat from the conditioned space, which must be made up by the heating equipment. In addition, heat energy can be recovered and used by the heating equipment, thus reducing the heating energy consumption and cost. These end uses comprise about 66% of total building, 67% of electric, and 61% of total natural gas end-use energy consumption.(3)

Displaced Technology: Conventional refrigeration equipment in food-sales buildings.

Performance Target: Reduced energy for building HVAC and refrigeration equipment during the next 15 to 20 years, specifically at least 15% for supermarket refrigeration and HVAC while reducing refrigerant needed. For FY 2005, PNNL assumed an overall 22.5% reduction in HVAC end-use energy consumption.

Market Description: All commercial food-sales buildings.

Market Introduction: 2004; PNNL assumed this project would accelerate the introduction of this technology into the marketplace by 10 years.

4.5.5 Refrigerant Meter

4.5.5.1 Target Market

Project Description. This technology will increase the efficiency of residential and commercial space conditioning equipment and reduce peak energy use. Most air-conditioning units and heat pumps have an improper refrigerant charge level or other issue resulting in a COP that is lower than the rated design. These meters will inform the homeowner or business owner of the current state of charge or performance of their space conditioning equipment and ultimately the increased cost. PNNL determined this project's energy savings by using BEAMS and applying overall percentage reductions in vapor compression heating and cooling energy consumption.

Market Description. Residential and commercial space-conditioning equipment.

4.5.5.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. This product is expected to have the following characteristics:

- Cost of Conventional Technology: $0.
- Cost of BT Technology: $100.
- Incremental Cost: $100.

4.5.5.3 Methodology and Calculations

Inputs to Base Case. The base case was developed based on an assortment of sources, including AEO 2003, CBECS 95, RECS 97, and several other sources, all of which are documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al).

Technical Characteristics. This technology will increase the efficiency of residential and commercial space conditioning equipment and reduce peak energy use. Most air-conditioning units and heat pumps have an improper refrigerant charge level or other issue resulting in a COP that is lower than design. These meters will inform the homeowner or business owner of the current state of charge or performance of their space conditioning equipment and ultimately the increased cost. Given this information, that is not readily available, it is expected that prudent owners will get the situation corrected. PNNL determined this project's energy savings by using BESET and applying overall percentage reductions in vapor compression heating and cooling energy consumption.

Table 17. Assumed Reductions in Energy Use for Refrigerant Pressure Charge Meters and COP Meters

End Use	Percentage Reduction in Energy Consumption
Residential Heat Pump Heating	23.9*
All Residential Cooling (includes heat pumps)	23.9
Commercial Heat Pump Heating	12.0**
Commercial Vapor Compression Cooling (includes heat pumps and excludes chillers)	12.0

* This value is based on a frequency distribution of undercharging and overcharging and on an efficiency impact associated with each level of undercharging and overcharging. http://www.proctoreng.com/checkme/technical.html.
** While the impact of undercharging and overcharging in commercial equipment is roughly the same as residential equipment, the frequency of undercharging and overcharging is believed to be about half that in residential equipment.

Expected Market Uptake. The market penetration goal is to impact 50% of all applicable residential units by 2020 and 90% of all applicable commercial units by 2020 (see **Figure 9** and **Figure 10**). Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The "Accelerated" penetration curve represents the percent of superwindow sales with the DOE project; the "Net" penetration curve represents the percent of sales attributable to DOE, as PNNL assumed that the DOE project would accelerate market acceptance by 10 years.

4.5.6 Sources

(1) FY 2002 Budget Request - *Data Bucket Report for Space Conditioning and Refrigeration: Refrigeration Program* (internal BT document).
(2) Arthur D. Little, Inc. 1996 *Energy Savings Potential for Commercial Refrigeration Equipment.* Reference 46230-00. Cambridge, Massachusetts.
(3) Belzer, D.B and L.E. Wrench. 1997. *End-Use Consumption Estimates for U.S. Commercial Buildings, 1992*. PNNL-11514, Pacific Northwest National Laboratory, Richland, Washington.
(4) Brookhaven National Laboratory. 2001. *Better Duct Systems for Home Heating and Cooling*. BNL-68167, Vol. 4, Upton, New York, p.10.
(5) Brookhaven National Laboratory. 2001. *Better Duct Systems for Home Heating and Cooling*. BNL-68167, Vol. 3, Upton, New York, p.1.

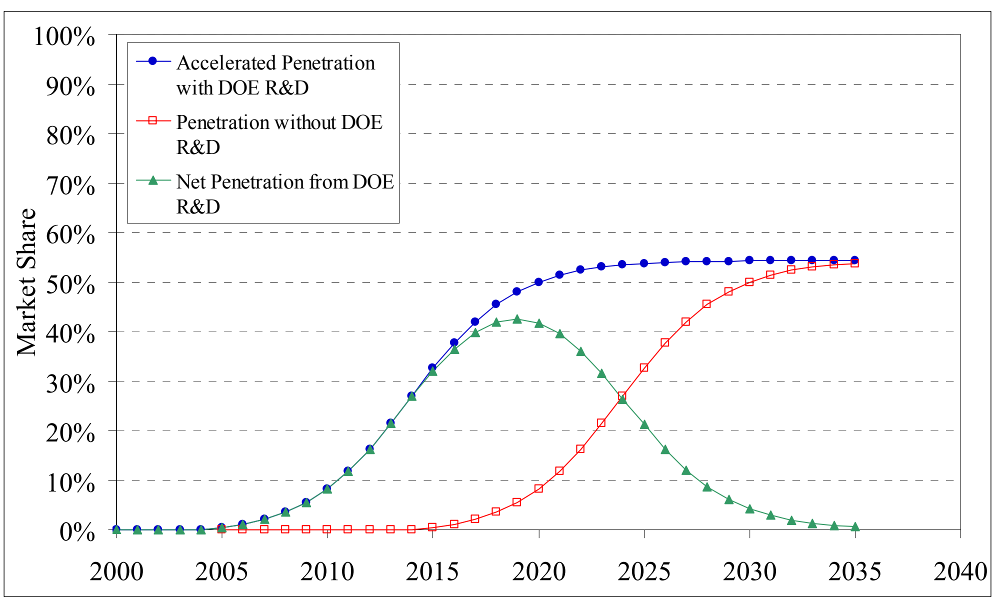

Figure 9. Residential Market Penetration Curves for COP and Refrigerant Pressure Change Meters

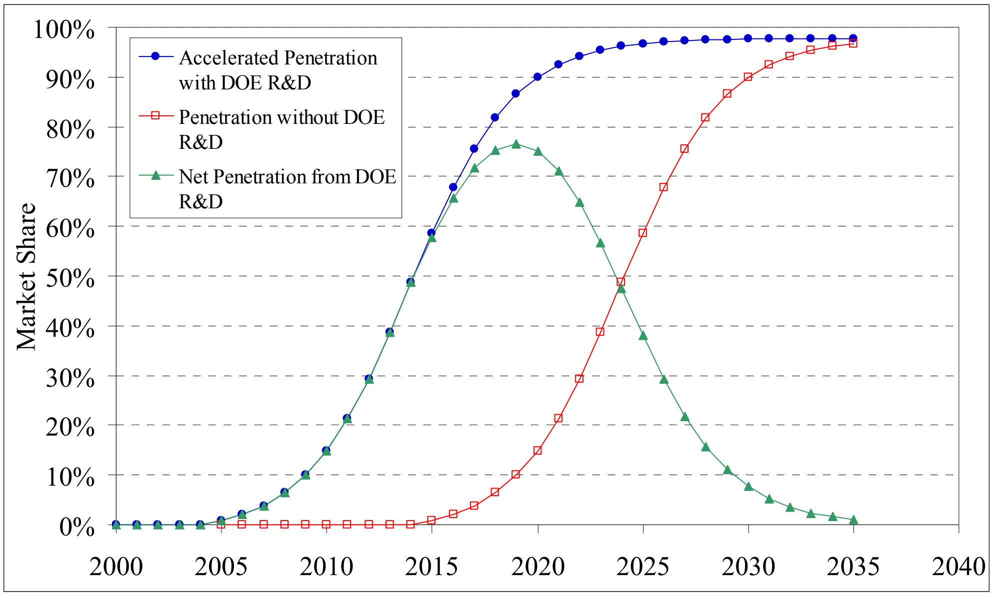

Figure 10. Commercial Market Penetration Curves for COP and Refrigerant Pressure Change Meters

Appendix D – GPRA05 Distributed Energy Program Documentation

Program Objective

The major programs modeled for DE include:

Industrial Gas Turbines
Advanced Microturbines
Gas-Fired Reciprocating Engines
Thermally Activated Technologies
Distributed Energy Systems Applications Integration
Cooling Heating and Power Integration
The Technology Base – (Advanced Materials and Sensors is not modeled directly because its benefits are represented in the other programs).

Methodology and Calculations

Because the time horizon of the *Annual Energy Outlook 2003* Reference Case (AEO-3 case) version of the National Energy Modeling System (NEMS) is 2025, and the goals of Distributed Energy (DE) programs are relatively short-term, the approach taken in this GPRA cycle is that most of the outputs are captured before that date. However, DE programs are part of a wider effort to transform the power system from its current highly centralized form to a more robust decentralized paradigm, a transformation with a longer time horizon than NEMS-GPRA provides.

Distributed generation (DG) appears in multiple modules (roughly corresponding to subsectors of the full energy sector, i.e. utility, commercial, etc.), which hinders the DE program's use of NEMS-GPRA. Further, only a limited number of technology slots are typically available to represent a broad array of equipment types, sizes, and configurations. For example, the reciprocating engines in the commercial sector all have combined heat and power (CHP) heating (but not cooling) capability, while those in the utility sector do not—in some instances, engines without CHP might be attractive in the commercial sector and vice-versa. Proper representation of DE program goals includes an accurate representation of DE's technology-advancement targets, as well as an accounting for the limitations in the structure of NEMS, which can hinder estimation of the benefits that can be realized from DG technologies. Therefore, in addition to changing input assumptions relative to the AEO-3 version of NEMS, other *fixes* to perceived limitations or omissions are also appropriate in both the base and program cases.

Inputs to Base Case

Expectations of improvements in technologies embedded in the AEO-3 reference case, which presuppose existence of DE programs, need to be eliminated from the base case (referred to as the baseline) for comparisons with achievement of program goals. Two full sets of forecast scenarios are actually needed, *with* and *without* DE programs in place; and the AEO-3 case is likely, although not certain, to fall between. In the FY 2005 GPRA (GPRA05), the baseline case generally corresponds to the AEO-3 reference case, though there are exceptions as described below. Estimation of the benefits of the programs is based on a comparison of the *baseline* and *program* scenarios. In this analysis, both scenarios were effectively estimated together, as two deviations from the AEO-3 case—therefore, they are presented together in the following section.

NEMS-GPRA Inputs

NEMS-GPRA input specifications follow by program, and all are summarized in **Table 3**. Inputs for each program are briefly described in the following sections.

The AEO-3 case and prior GPRA forecasts were compared with a draft of the National Renewable Energy Laboratory's (NREL) and Gas Technologies Institute's Technology Characterizations (TeChars) for three technologies: microturbines, gas engines, and industrial gas turbines. Further data from the subsequent revisions released at a July 2003 workshop in Washington was used, together with some responses to the TeChars draft. With a few noted exceptions, technology cost and *electrical* efficiency inputs are derived both from the TeChars and from DE program goals, while *combined* efficiency values are derived from other sources. The TeChars is now finalized and available.[1]

To simplify and clarify the graphs, not all generator capacity sizes are shown. The technology inputs for baseline and program cases generally correspond to the same-sized units as NEMS-GPRA uses—though, in some instances, the GPRA05 inputs correspond to larger systems, i.e. when the standard AEO-3 capacity is unrepresentative. For clarification, a summary table of technology type, module, and nameplate capacities represented in the AEO-3 case —and corresponding nameplate capacities for GPRA05 technology inputs—is included in **Table 1**.

Table 1. Summary of Technology Size Representation by Module

Technology Type	Module	Representative Size in NEMS	Corresponding Size in GPRA05
Gas Turbine	Commercial	1 MW	5 MW
	Industrial	1 MW, 5 MW, 10 MW	1 MW, 5 MW, 10 MW
	EMM	2 MW	5 MW
Microturbine	Commercial	100 kW	Baseline: 200 kW in 2015, 500 kW in 2025 Program: 200 kW in 2005, 500 kW in 2010
Gas Engine	Commercial	200 kW	800 kW
	Industrial	800 kW, 3 MW	800 kW, 3 MW
	EMM	1 MW	800 kW

[1] Goldstein, Larry, Bruce Hedman, Dave Knowles, Steven I. Freedman, Richard Woods, and Tom Schweizer, (November 2003). "Gas-Fired Distributed Energy Resource Technology Characterizations," NREL/TP-620-34783.

While many of the technology inputs reflect the achievement of DE program goals in 2010, the exact replication of this time frame is not always possible because of certain model constraints. For example, technological progress in the *commercial* module is limited to a step-function advance, and input values are updated on a five-year time step. These limitations are shown graphically below, where applicable.

Industrial Gas Turbines

Gas turbine sizes in NEMS-GPRA range from 1 to 40 MW, and explicitly appear in the commercial and industrial demand modules, and less definitively in the utility electricity market module (EMM), where the technology type is defined generically as either a base-load or peak system. The industrial-sector turbines cover a wide size range, but proposed inputs to the FY05 GPRA process focus on the 1 MW-, 5MW-, and 10 MW-size systems. The commercial sector contains a single representative turbine sized at 1 MW. The inputs for the commercial turbine were adjusted to reflect the range of sizes that will likely be adopted in that sector. The baseline and program case inputs for the commercial sector correspond to the 5 MW system shown in the graphs below. Also, the 2 MW base-load EMM generator is represented as a gas turbine.

The *baseline* input values for gas turbines reflect a 1% improvement in electrical efficiency for 1 MW, 5 MW, and 10 MW turbines, relative to the TeChars values. There is no cost difference between baseline and program cases. Finally, baseline combined efficiencies are derived from an unpublished source, and are below AEO-3 values.

The *program* input values are the TeChars values for cost and electrical efficiencies. The main objective of this program currently is NOx and CO emissions reduction; but, because these are not reported metrics, forecasts for these improvements are not included here.

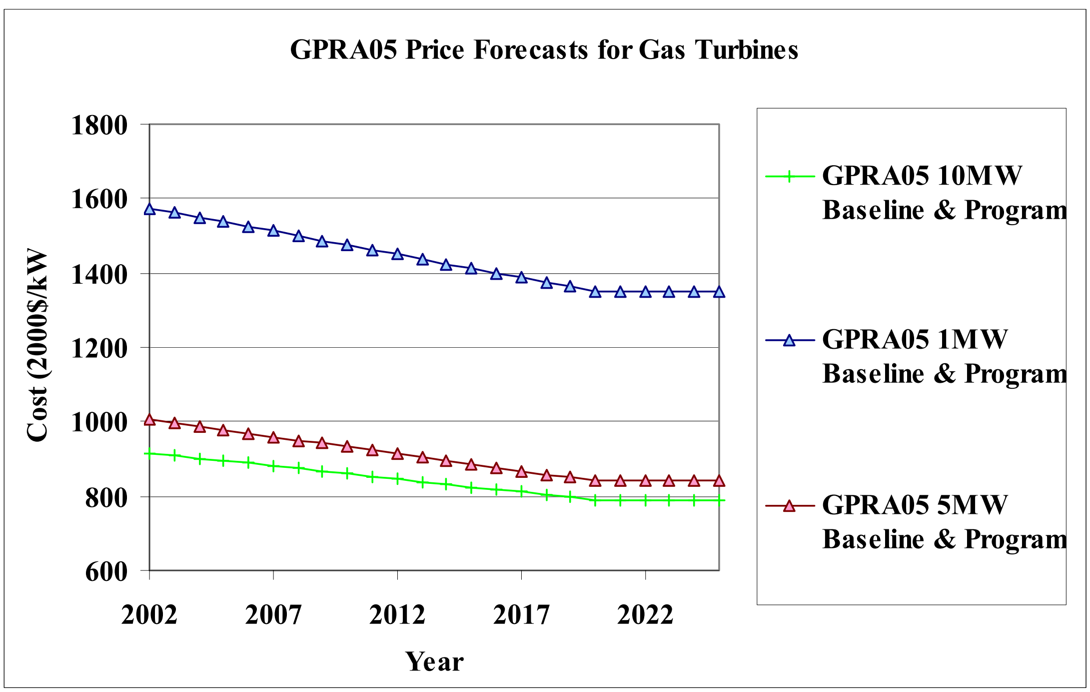

Figure 1. Industrial Gas Turbine Installed Cost (2000 $/kW)

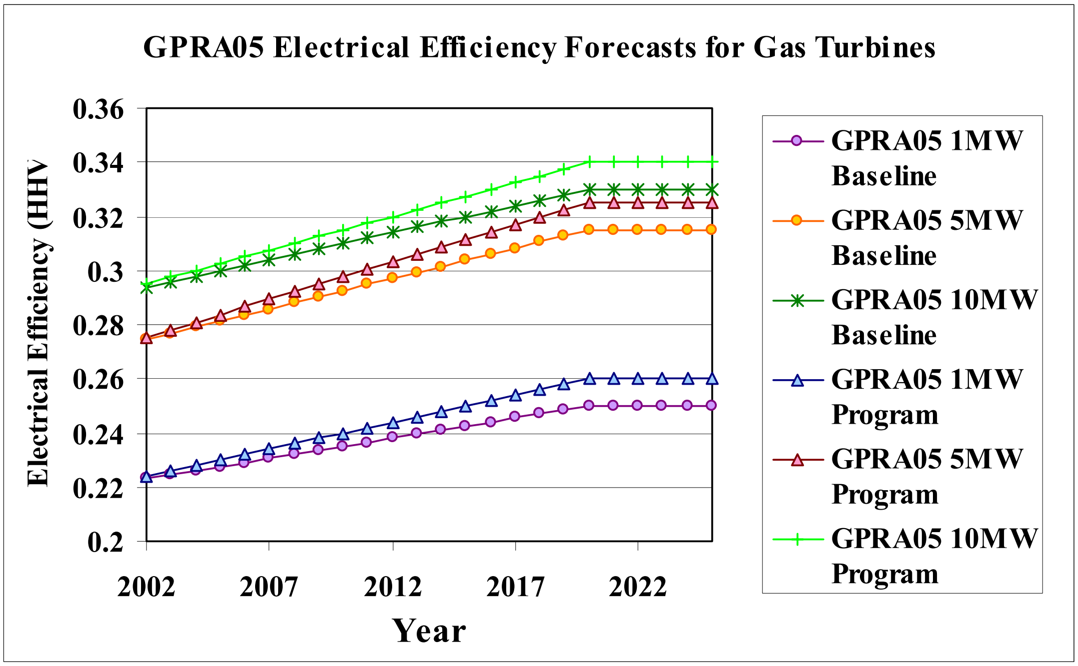

Figure 2. Industrial Gas Turbine Electric Efficiency

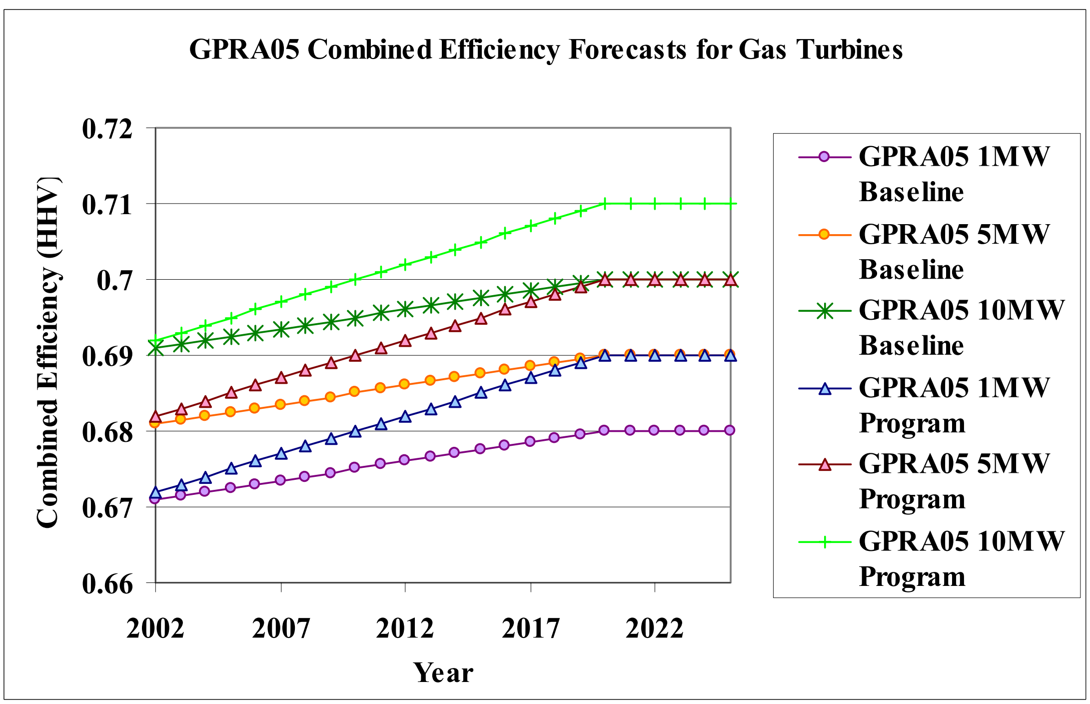

Figure 3. Industrial Gas Turbine Combined Efficiency

Advanced Microturbines

Microturbines occur only in the commercial module as a representative 100 kW system. Therefore, NEMS-GPRA is failing to capture two key aspects of this emerging technology. First, it is likely to be deployed in other sectors; for example, its tolerance to low-quality fuel makes it highly attractive for landfill and sewage-treatment gas applications. Second, larger-sized microturbines are emerging and promise higher efficiencies and lower costs than the NEMS-GPRA representative 100 kW unit. Little can be done directly to rectify the first problem in this GPRA cycle, but the future availability of larger sizes is represented by dramatically improved performance of the 100 kW unit after 2010.

The *baseline* input values for costs and electricity conversion efficiency are the AEO-3 assumptions. Combined efficiencies are higher than the AEO-3, hitting 70% by 2020.

The *program* input values are a 40% simple efficiency and a target $575/kW first cost by 2010, and then remain flat.[2] Combined efficiency values reach 72% by 2020.

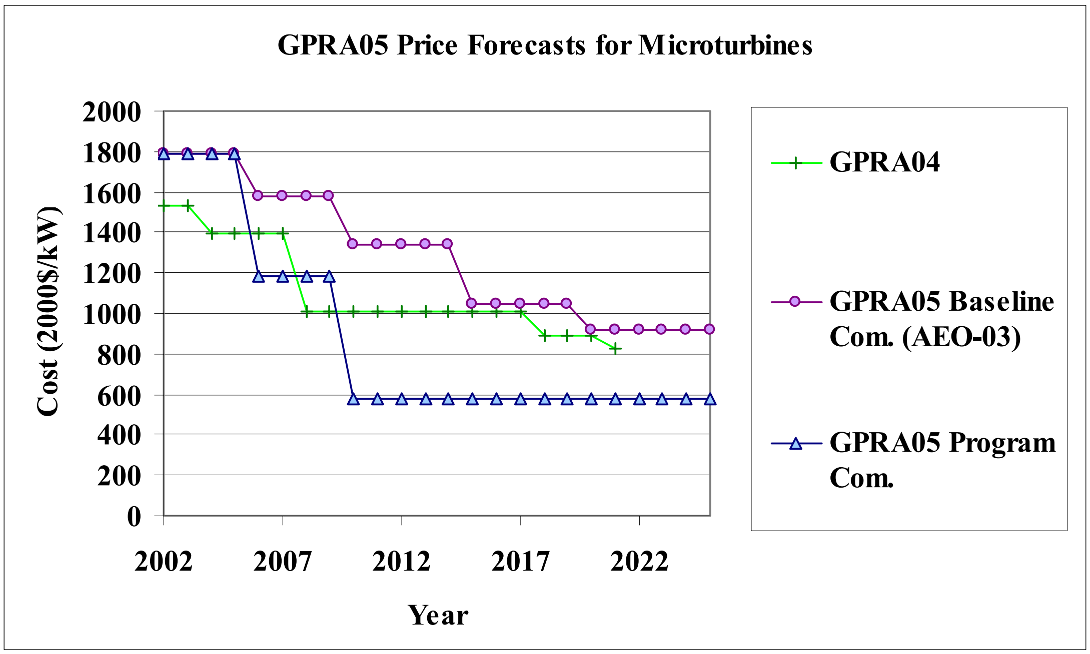

Figure 4. Microturbine Installed Cost (2000 $/kW)

[2] The Advanced Microturbines Program goal is $500/kW, and these inputs are based on an additional first cost for CHP-enabled systems.

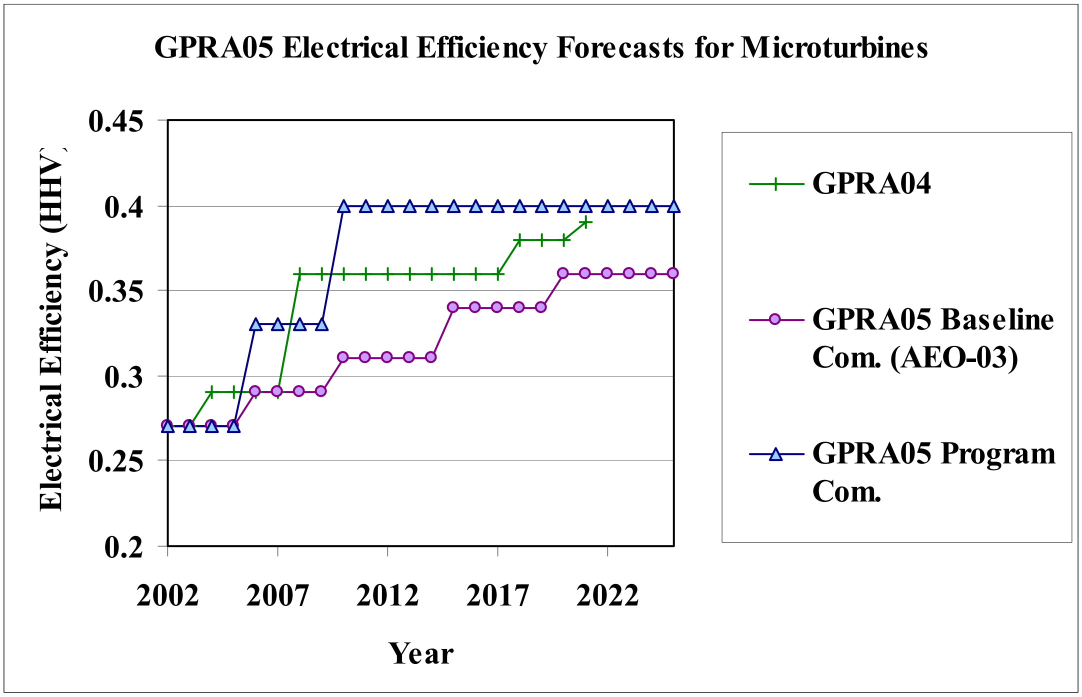

Figure 5. Microturbine Electric Efficiency

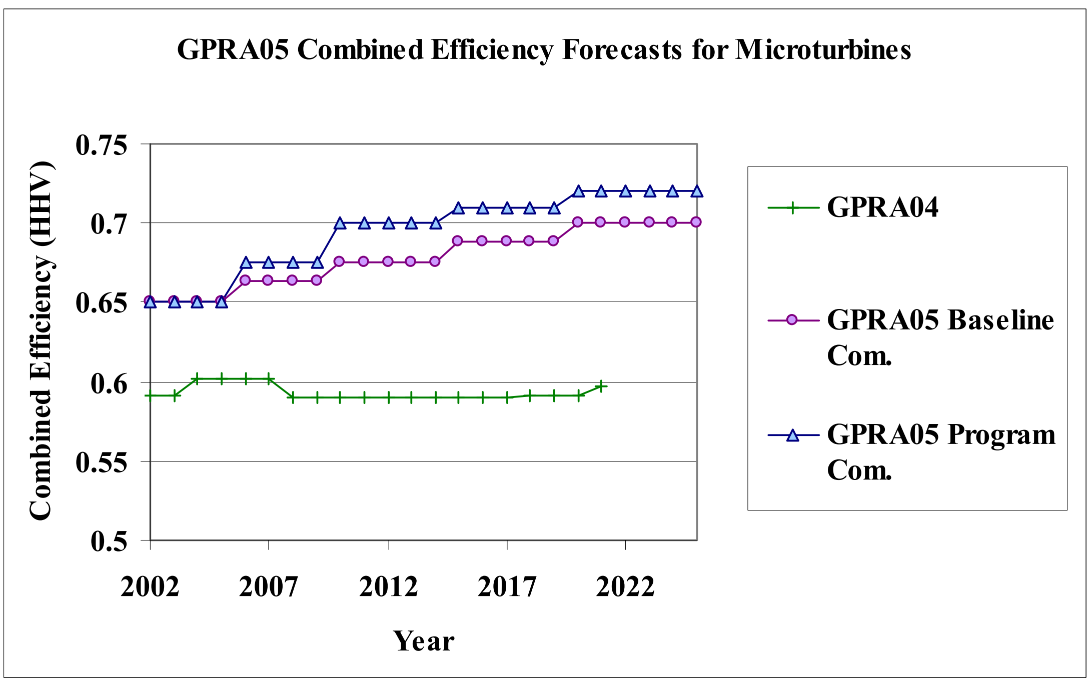

Figure 6. Microturbine Combined Efficiency

Gas-Fired Reciprocating Engines

Gas engines appear in several modules in NEMS, in both CHP and simple-cycle configurations—but only one or two marker models represent the wide range of available engines (see **Table 1**). The limited number of available technology slots—together with the maturity and clear attractiveness of gas engines in many configurations—makes the choice of inputs for this technology somewhat complex.[3] The commercial module has a marker 200 kW CHP-enabled unit, the industrial module has 800 kW and 3 MW CHP-enabled units, and the 1 MW unit that appears in the EMM is also taken to be a simple-cycle gas engine.

The *baseline* input values for costs and electricity conversion efficiency are the AEO-3 assumptions. Combined efficiencies deviate significantly from the AEO-3.

The *program* input values for both the commercial-sector engine and the 800 kW industrial-sector engine are a 40% simple efficiency and a target \$570/kW first cost by 2010, combined with a 71% combined efficiency by 2020. Again, this target represents improvements resulting from the program, as well as the emergence of larger engines available in the commercial sector. The 3 MW system in the industrial module has equivalent 50% electric efficiency and \$500/kW targets by 2010, and 69% combined efficiency values by 2020.

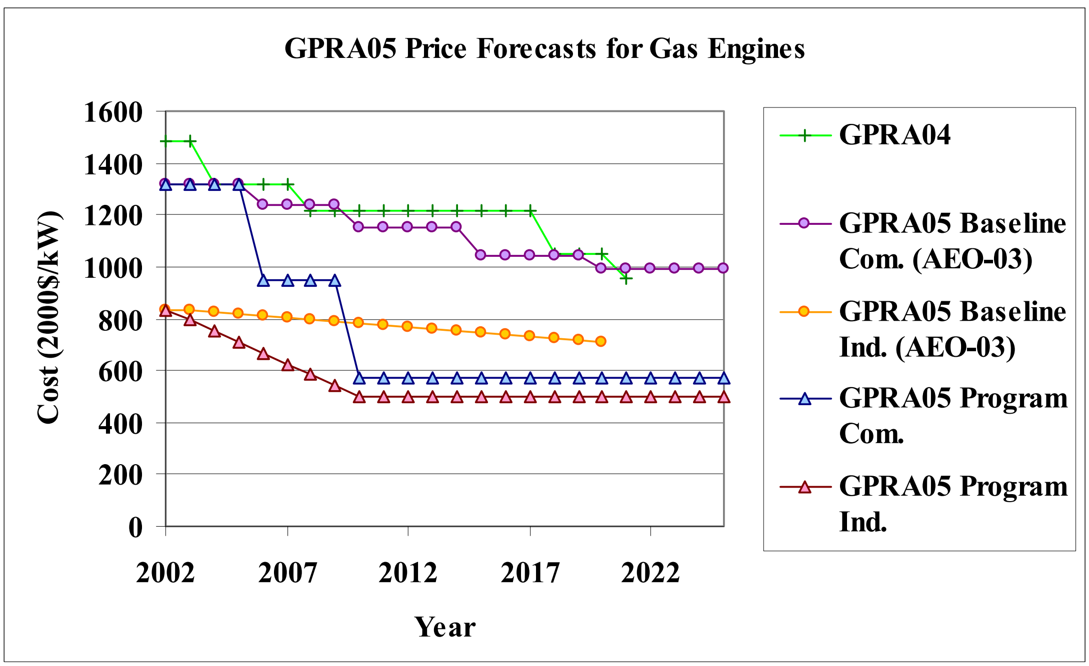

Figure 7. Gas Engine Installed Cost (2000 $/kW)

[3] Heat recovery can be from exhaust gas or jacket coolant, and a promising CHP application is absorption- cycle cooling, which is non-existent in NEMS-GPRA.

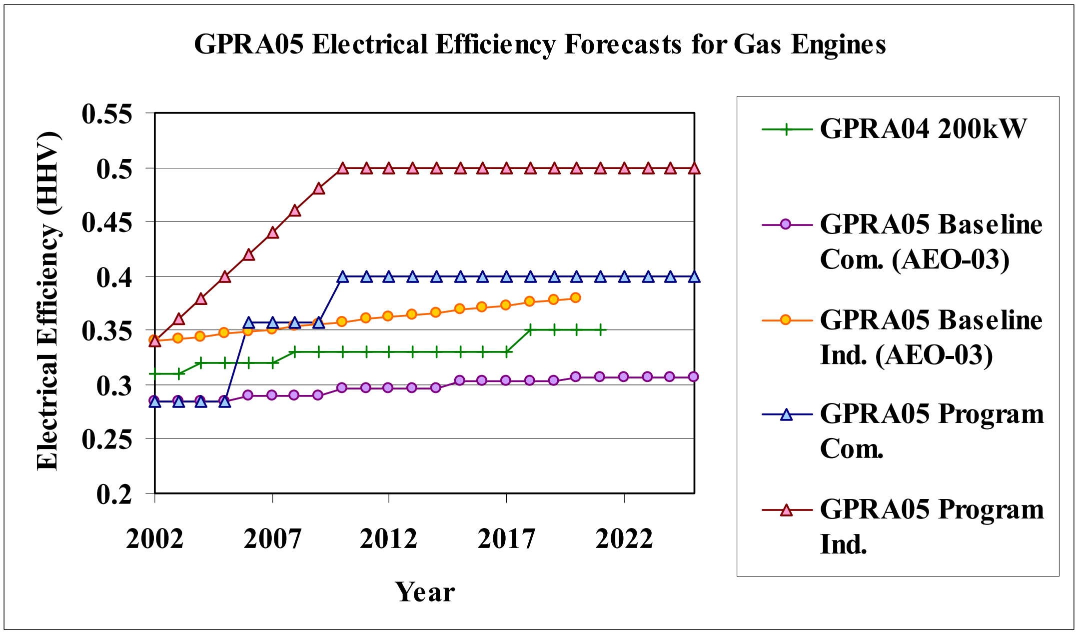

Figure 8. Gas Engine Electric Efficiency

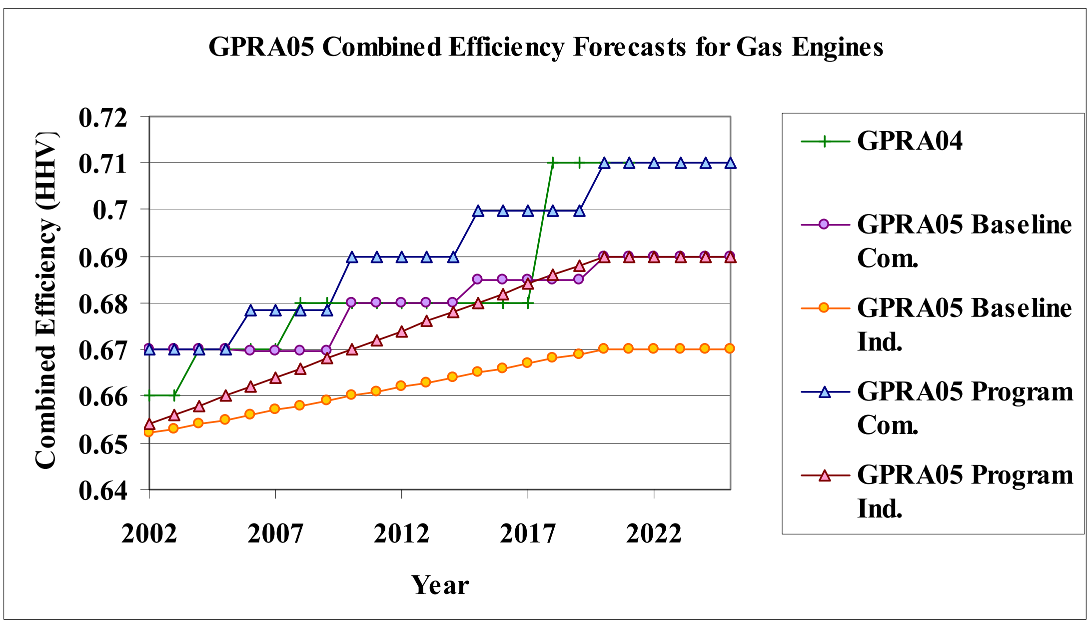

Figure 9. Gas Engine Combined Efficiency

Technology Representation in the Utility Sector (Electricity Market Module)

The EMM contains two generic DG technologies: a 2 MW base-load system and a 1 MW peak-load system, neither with CHP capability. Baseline and program representation of these technologies will correspond to a gas engine for the peak system (using the 800 kW system values stated above) and a gas turbine for the base system (using the 5 MW system values stated above). Although CHP applications may be attractive to utilities, DG systems in the EMM do not include heat-recovery components, and therefore projected technology costs are slightly lower.

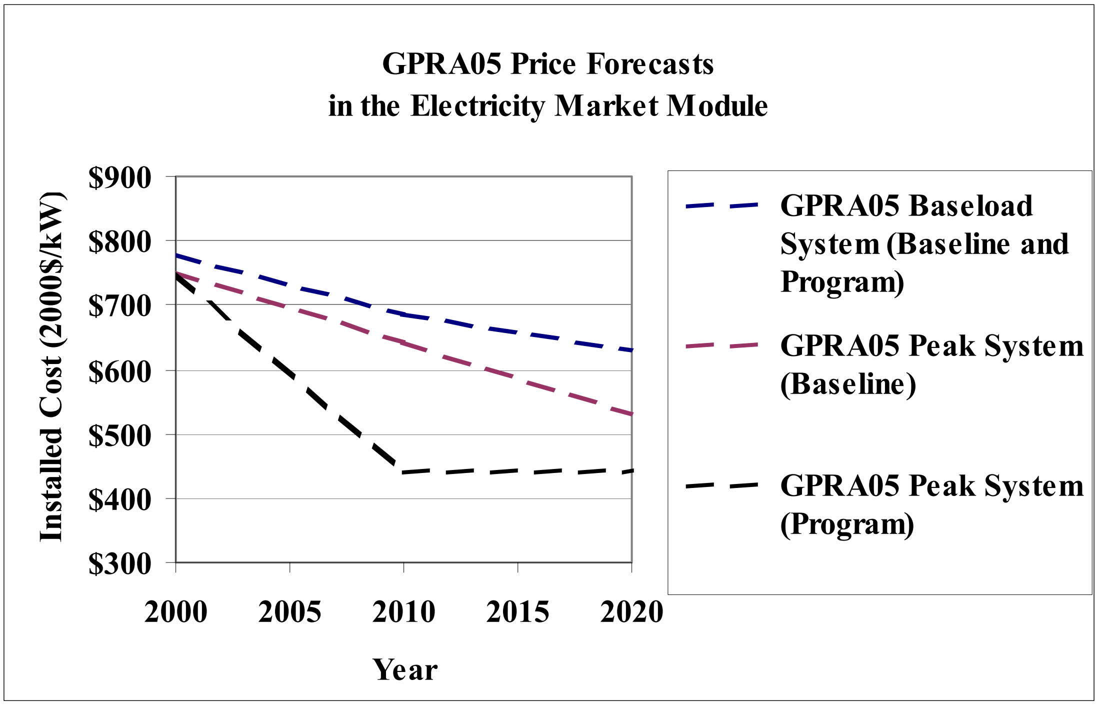

Figure 10. Electricity Market Module Installed Cost

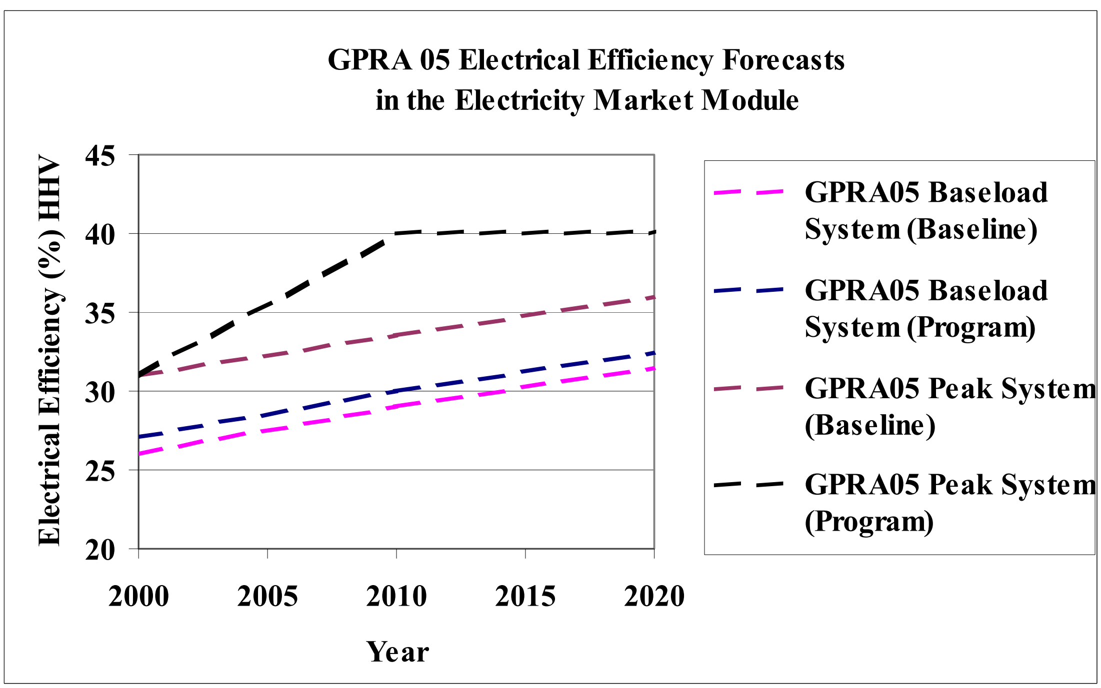

Figure 11. Electricity Market Module Electrical Efficiency

Advanced Materials

No separate inputs to represent this program are proposed. The benefits of this activity are represented in the preceding technology-development activities.

Thermally Activated Technologies

DE's thermally activated technologies program includes direct-fired absorption chiller technologies and desiccant dehumidification systems. Only the former are represented here as changes applied to gas-fired absorption chillers in the commercial technology input file.

The NEMS-GPRA commercial module represents the commercial building stock using 11 representative building types. Of these, the commercial technology input file restricts gas-fired absorption chillers from being installed in the following building types: food sales, food service, small office, warehouse, and other. These restrictions are removed for both the baseline and program cases to allow small commercial-sized systems to be installed in all buildings.

The assumptions for the program case inputs include: cost-improvement data taken from Resource Dynamics' study of integrated energy systems[4] with future cost values (2005+) available in 2010; double-effect chillers are approximately 1.5 times the cost of single-effect chillers; and technology costs correspond to 50–100 cooling ton[5] range.

The *baseline* case, based on a double-effect chiller introduced in 2020, uses cost assumptions from the AEO-3.

The *program* case is based on a double-effect chiller introduced in 2005.

Table 2. GPRA 05 Inputs for DE's Thermally Activated Technologies Program

	Baseline Case			Program Case		
Year	COP	Cost ($/kBtu/hr)	Cost ($/Ton)	COP	Cost ($/kBtu/hr)	Cost ($/ton)
2000	0.7	78.75	945	1	78.75	945
2005	1	78.75	945	1.2	59.08	709
2010	1	78.75	945	1.2	53.50	642
2020	1.2	78.75	945	1.4	42.50	510

[4] LeMar, P. (August 2002). "Integrated Energy Systems (IES) for Buildings: A Market Assessment," Resource Dynamics.

[5] *1 cooling ton is equal to 12,000 Btu/hr or approx 3.5 kW thermal.*

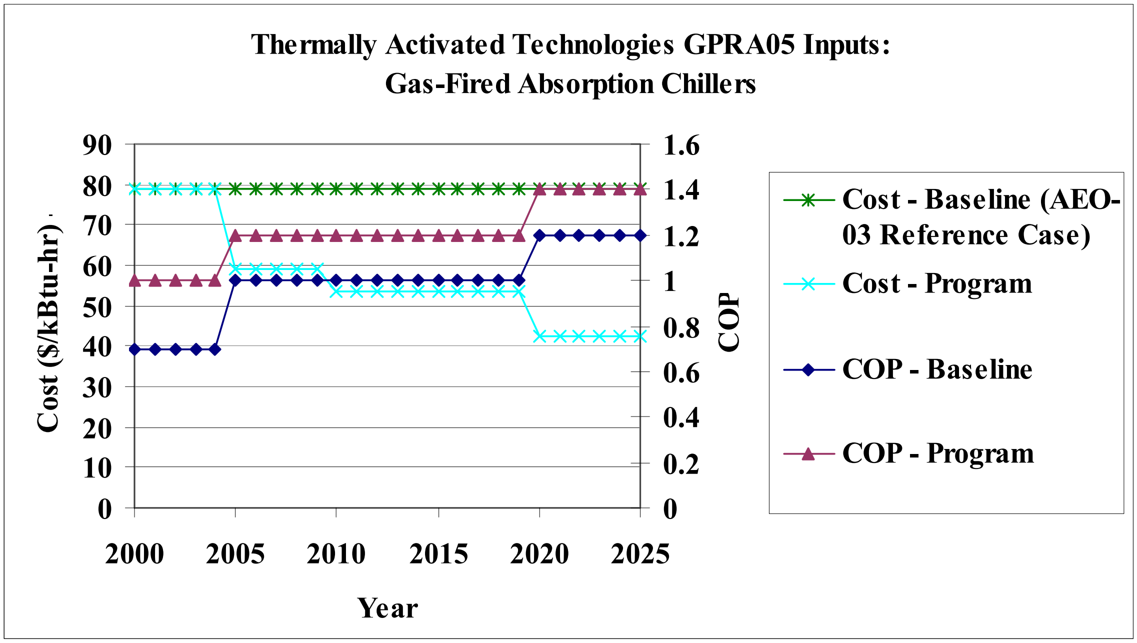

Figure 12. Thermally Activated Cooling Technology Inputs

Distributed Energy Systems Applications Integration

The Distributed Energy Systems Applications Integration (DESAI) Program' strives to accelerate adoption of DG technologies in certain sectors, especially among the existing building market (i.e. through retrofits). The NEMS model calculates DG adoption in *existing* buildings as a set share of the adoption in *new* buildings, and that share is set at 2% in the AEO-3 reference case. Because the retrofit market is the primary target of the DESAI Program, the outputs are represented by an increase in the cap on the share of existing commercial sites that can adopt DG.

The *baseline* input values are achievements of cost and efficiency targets by 2010, as described above in Sections 0–0. The existing building adoption rate is 2% of new buildings, equivalent to the AEO-3 value.

The *program* input values increase the share of existing buildings eligible to adopt DG from 2% to 10% of new buildings.

As part of the DG adoption logic fixes described in Section 9, additional changes to the new building adoption parameter were made in addition to the DESAI Program representation.

Cooling Heating and Power Integration

This program develops improved CHP packages and otherwise supports the market penetration of CHP technologies, including indirect-fired absorption chillers. Because NEMS-GPRA does not have a representation of indirect-fired absorption chillers, this program is represented by a proxy improvement in the payback period of the prime mover technology equivalent to the economic benefit of using 25% of the generator waste heat for a cooling end use.

The *baseline* input values are AEO-3.

The *program* input values are a reduction of one year of payback for the three prime movers. This payback reduction is calculated to be the effect on whole-system payback for an increase in absorption chiller COP from 0.7 to 1.2.

DG Adoption Logic Fixes

Two fixes were made to the DG adoption logic of new buildings in the commercial sector of NEMS-GPRA for both baseline and program cases. The adoption algorithm for DG in new buildings caps the maximum market adoption rate (the *penparm* parameter) at 30%for a one-year payback level. The cap on adoption rates for different paybacks (max *pen)* decays as an inverse function at a rate of 1/years to positive cash flow, and this decay is known as the payback acceptance function (shown as equation 1 below).

$$\max pen = \frac{penparm}{payback} \quad (1)$$

This approach severely disfavors technologies with paybacks that are moderate but still quite acceptable to many building owners—such as in the three- to six-year range—while it allows smaller adoption at very long paybacks, such as 15 years.

First, the cap for new buildings with a one-year payback (represented by the *penparm* parameter) is raised from 30% to 50%. A similar change was made in the GPRA04 analysis.

Second, the payback acceptance function is changed from an inverse decay function to one based on data of observed customer adoption of energy efficiency projects as a function of simple payback time[6]. These data are shown below for buildings in the institutional sector (n=768) and commercial buildings in the private sector (n=108).

[6] *Market Trends in the U.S. ESCO Industry: Results from the NAESCO Database Project*. Goldman, C., J. Osborn and N. Hopper, LBNL, and T. Singer, NAESCO, May 2002, LBNL-49601.

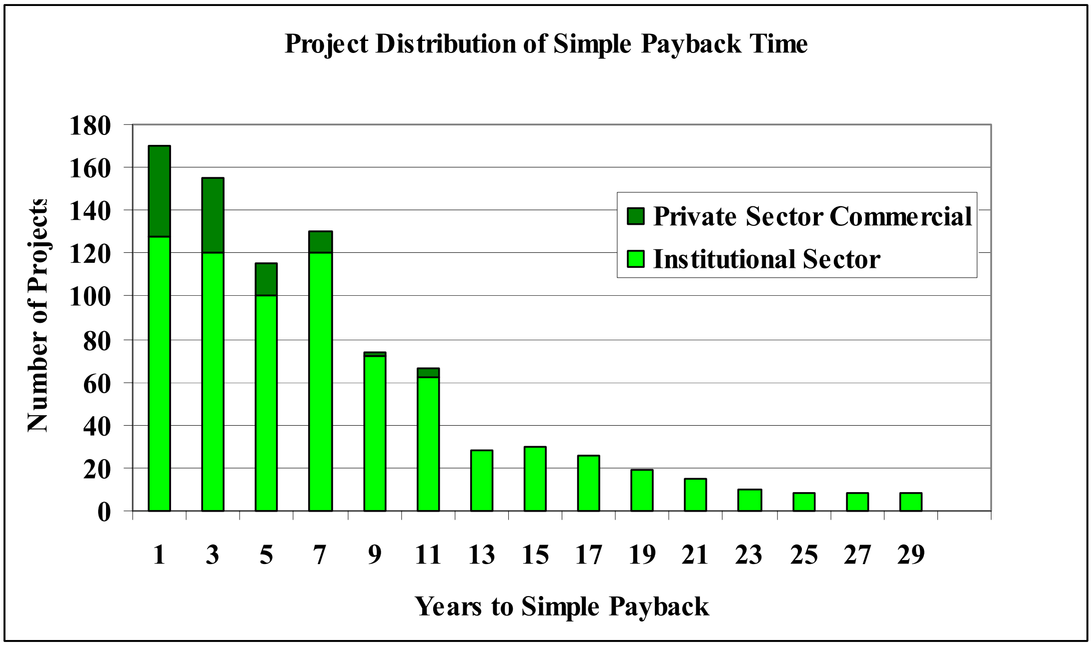

Figure 13. Distribution of Years to Simple Payback

To determine a decay function for the max *pen* based on this data set, the percentage of potential adopters from the total sample for each given payback year is calculated. It is assumed that for a given payback year, all of the adopters in that year and all adopters of projects with shorter payback periods would adopt, i.e. all columns are summed to the right in **Figure 13**. For example, all adopters of projects with 29-year paybacks also would adopt projects with 27-year paybacks, 25-year paybacks, etc. The resulting customer-acceptance curve is shown in **Figure 14**, along with the mathematical representation of the revised curve for input to NEMS-GPRA and the current equation used in the AEO-3. **Figure 14** shows that a maximum of 100% will adopt, and this represents 100% of the sample size; however, in NEMS-GPRA, the percentage of the total population that actually will adopt is scaled down using the *penparm* parameter (set at 50% for GPRA05), as discussed above.

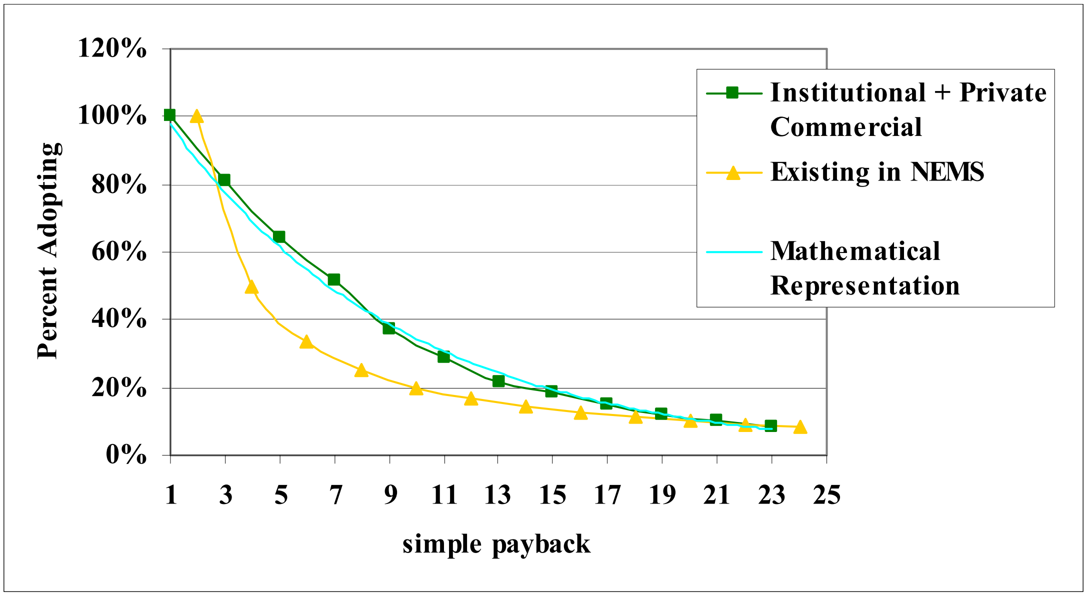

Figure 14. Decay Function of the Maxpen

Because NEMS-GPRA uses years to positive cash flow[7] (rather than payback period) as the primary metric of DER adoption, the data in Figure 14 has been converted to this metric by dividing the simple payback time in half. Justification for this conversion was determined by a simple spreadsheet analysis, using the financing assumptions that are used in NEMS-GPRA. Ultimately, the decay above is represented by equation 2 below as a function of the *payback* variable as defined in NEMS-GPRA:

$$\max pen = \frac{1.1 penparm}{e^{0.24\, payback}} \quad (2)$$

Two additional NEMS-GPRA fixes have been implemented in the base and program cases to ensure that the changes to the adoption logic described above do not result in an exaggerated number of DG adoptions. First, a fix to the model developed by OnLocation, Inc., subtracts the share of existing buildings that already have adopted DER systems from the pool of eligible existing buildings to prevent oversaturation of the market. Second, an internal check is included to ensure that the percentage of existing buildings that have DER systems installed will not exceed the cap imposed on new buildings. This will prevent a case where the installations in new buildings are not allowed to reach the rate of existing buildings.

The NEMS-GPRA fixes, along with additional minor changes, are summarized in **Table 4**.

[7] The NEMS *payback* (or *simple payback)* variable is defined as the first year in the cash-flow stream for which an investment has a positive cumulative net cash flow. *(EIA, NEMS Commercial Module Documentation Report 2003)*

Market Uptake

No wider market potential or penetration analyses were done exogenously to NEMS-GPRA for this work. The market definition and penetration rates for DG are those that are endogenous to NEMS-GPRA, and these are described briefly here for the EMM and the commercial-demand module.

In the EMM, the market is driven by the growing electricity-demand forecast and the deferred cost of transmission and distribution (T&D) expansion. The two available DER generators (the peak and base-load units) compete against the cost of central-station generation and T&D upgrades to supply growing demand and replace retiring generating capacity. The total capacity of DG is constrained to correspond to a specific level of avoided T&D costs, indicating that there is a maximum economic value of T&D deferrals that DG can provide.[8]

In the NEMS commercial sector, the market is represented by 11 building types and is disaggregated into the nine geographic census divisions. Annual penetration into the new-building market is determined by the economic attractiveness of on-site generation with heat recovery relative to the purchase of electricity and other fuels. The retrofit market is not characterized distinctly, and the market adoption is simply proportional to the new-building adoption. Distributed generation adoption in the commercial sector is dominated by a few building types. The education, lodging, and mercantile/service sectors account for the large majority of DG capacity additions from the DE program. Regional DG adoption is distributed more evenly among census divisions, though the Pacific and Middle Atlantic regions account for a larger share of DG adoption, partly because of the higher electricity demand and prices forecasted for those regions.

Because DG market segments are broadly characterized in NEMS, an accurate representation of niche market adoption is difficult to include exogenously in NEMS-GPRA. Several niche market segments that contribute to the total market for DG (such as markets for reliability, security, or environmental benefits) are not represented in NEMS-GPRA.

[8] Energy Information Administration (2003). “The Electricity Market Module of the National Energy Modeling System: Model Documentation Report,” U.S. Department of Energy, Washington, D.C. pg.91.

Table 3. Summary of DE Program and Baseline Representation in GPRA05

	DE Program	Program Goals	Representation in NEMS-GPRA	
			Baseline	Program
Technology Development	Industrial Gas Turbines	38% electric efficiency, <10% cost increase, <5 ppm NOx by 2007	Industrial module: 1% reduction in electrical efficiency for 1, 5, and 10 MW systems; combined efficiency values at 68%, 69%, and 70% respectively by 2020. Commercial module set to 5 MW values	Industrial module: NREL TeChars for 1, 5, and 10 MW system; combined efficiency values at 68%, 69%, and 70% respectively by 2010. EMM baseload unit considered a 5 MW turbine without CHO capability. Commercial module equivalent to 5 MW values.
	Advanced Microturbines	40% electric efficiency < $500/kW NOx < 7ppm	AEO-3; 70% combined efficiency by 2020	40% electric efficiency, $575/kW, 72% combined efficiency by 2010[9]
	Gas-Fired Reciprocating Engines	45% electric efficiency (HHV) $400-450/kW 0.13 g/kWh	AEO-3; 69% combined efficiency in commercial module by 2020, 67% combined efficiency in industrial module by 2020	200 kW commercial module and 800 kW industrial module units: 40% electric efficiency, $570/kW, 69% combined efficiency by 2010; Industrial module 3 MW unit: 50% electric efficiency, $500/kW, 67% combined efficiency by 2010[10]; EMM 1 MW peaker unit treated as an 800 kW engine.
	Technology Based-Advanced Materials and Sensors	Advanced material research to assist in other program goals	No additional changes	Included in acceleration cases represented by End-Use Integration programs
	Thermally Activated Technologies	Cost and efficiency improvements for direct-fired absorption chillers	COP of 1.2, $78.75/kBtu-hr by 2020; allow installations in all building types	COP of 1.4, $42.50/kBtu-hr by 2020; allow installations in all building types

[9] Cost and electrical efficiency values from program goals; combined efficiency values from NREL 200 kW system. (NREL Technology Characterizations Workshop of Analysts and Modelers, Washington DC, July 9, 2003)

[10] Cost and electrical efficiency values from program goals, scaled for different system sizes in different NEMS modules; combined efficiency values from NREL 300 kW system in the commercial module and NREL 3 MW system in the industrial module. (NREL Technology Characterizations Workshop of Analysts and Modelers, Washington DC, July 9, 2003)

	DE Program	Program Goals	Representation in NEMS-GPRA	
			Baseline	Program
End-Use Integration	Distributed Energy Systems Applications Integration	Demonstration and integration projects in industrial sector, high-tech industry, hospitals, and other commercial sectors.[11]	Percent of existing buildings that adopt DER set at 2% of new buildings (same as AEO-3)	Percent of existing buildings that adopt DER increased to 10% of new buildings.
End-Use Integration	Cooling Heating and Power Integration	Added 8 GW electric capacity and 10 GW thermal capacity in buildings by 2010[12]; advance the use of indirect-fired absorption chillers in buildings	Chiller COP assumed to be 0.7	Chiller COP increase from 0.7 to 1.2, implemented as a 1-year payback reduction of prime mover coupled with electricity use reduction in commercial demand module that is yet to be determined.

[11] The National Accounts Energy Alliance focuses on "Fortune 1000, national chain end-users, including the retail, supermarket, food service, hotel, and healthcare industries."
[12] http://www.eere.energy.gov/der/thermally_activated/related_programs.html

Table 4. Additional NEMS-GPRA Enhancements for both the Baseline and Program Cases

Change	Module	Program or Baseline	Implemented in NEMS-GPRA	Source/Rationale
Maximum Annual Penetration Caps for New Buildings	Commercial	Both	*Penparm* parameter currently set to 30%, change to 50%	Change made in GPRA 04
Maximum Annual Penetration Caps for Existing Buildings	Commercial	Both	Remove penetration cap of 0.25% new building penetration	Additional methods are implemented to prevent oversaturation in existing buildings
Falloff of Maximum Annual Penetration Caps as a Function of Payback Years	Commercial	Both	Currently set as an inverse function: $\max pen = \frac{penparm}{simplepayback}$ Change to: $\max pen = \frac{1.1 penparm}{e^{0.24 simplepayback}}$	*Market Trends in the U.S. ESCO Industry: Results from the NAESCO Database Project*. Goldman, C., J. Osborn and N. Hopper, LBNL, and T. Singer, NAESCO, May 2002, LBNL-49601.
Remove DG Adopters in Existing Buildings from Pool of Potential Adopters	Commercial	Both	Subtract out share of existing buildings that adopted DG in previous year from current year stock	Prevent oversaturation of existing building stock
Implement non-linear technology advancement trajectory	Industrial	Program	Allow for technology performance and cost targets to be hit in 2010 and flat thereafter	Accurate representation of program goals

Appendix E – GPRA05 Federal Energy Management Program Documentation

Introduction

The mission of the Federal Energy Management Program (FEMP) is to promote energy security, environmental stewardship, and cost reduction through energy efficiency and water conservation, the use of distributed and renewable energy, and sound utility management decisions at Federal sites. [FY 2005 Congressional Budget Request, p. 475]

The Federal Energy Management Program goal is to provide technical and financial assistance to Federal agencies and thereby lead the Nation by example in use of energy efficiency and renewable energy. Through the Federal Government's own actions, FEMP's target is to increase Federal renewable energy use to 2.5% of total Federal electrical energy use by 2005, and reduce energy intensity in Federal buildings by 30% by 2005 (relative to the 1985 statutory baseline level of 138,610 Btu per gross square foot). By 2010, the target is to further reduce energy intensity in Federal buildings by 35% (relative to the 1985 statutory baseline level). [FY 2005 CBR, p. 476] Resource assumptions for FEMP are shown in **Table1.**

Table 1. Resource Assumptions for FEMP, FY 2004 to FY 2010
(in millions of nominal dollars)

FY04	FY05	FY06	FY07	FY08	FY09	FY10
19.716	17.9	17.9	17.9	17.9	17.9	17.9

Introduction to GPRA Metrics Approach

Pacific Northwest National Laboratory (PNNL) calculates the potential site energy impacts of FEMP's portfolio for DOE/EERE. The details of those mathematical calculations are available for review in an annotated Excel spreadsheet, which provides a transparent "A to Z" understanding of how the year 2010 impacts are estimated. Individuals interested in the specific details should refer to that file, available from PNNL by contacting Daryl Brown (daryl.brown@pnl.gov). FEMP's detailed spreadsheet model is not integrated into the larger FY 2005 GPRA models (NEMS-GPRA05 and MARKAL-GPRA05). However, to provide source energy savings, energy-expenditure savings, and carbon emission reductions attributed to FEMP, the outputs of the spreadsheet model are fed into the larger GPRA models exogenously and the larger model reports these benefits.

A detailed narrative description of the approach, and a summary of the results, follows below in the section Energy Savings Calculation Mechanics. The purpose of this introductory section is to provide a general understanding of the approach and assumptions at a higher level.

There are four key principles governing PNNL's estimation of GPRA metrics for FEMP.

First, the principal goal examined for metrics development is the 2010 site energy intensity goal for "standard" buildings and facilities described above. PNNL also estimates the impact of the Executive Order 13123 goal for energy-intensive operations, which is to reduce energy per square foot by 25% in 2010, relative to a 1990 baseline. Both of these goals are stated in terms of energy use, per year, per square foot of floor space. It is important to note that FEMP's mission is to assist the 31 Federal agencies in attaining these executive order goals for the Federal government. Strictly speaking, these are not goals for FEMP but goals for each individual agency, and their involvement is essential. As noted above, the Federal sector also has a renewables goal, but PNNL did not estimate the impact of this goal in the GPRA process. (Given that the renewables goal is for 2005, and that the benefits estimated are for the FY 2005 budget request, this is not a significant omission.)

Second, to estimate impacts in the Federal marketplace, PNNL treats the entire Federal Energy Management Program as one unified deployment program. That is, PNNL takes what is often called a "top-down" approach to calculate 2010 energy impacts. The impact of FEMP's broad portfolio of deployment activities—alternative financing, direct technical assistance, training and information, publication of the Annual Report to Congress, procurement recommendations—is estimated as one combined effect in the market, measured in terms of energy use per square foot per year. Put differently, separate impacts for each FEMP activity are *not* estimated and then summed; the approach is not "bottom-up."

Third, the target market is the Federal sector, the Nation's 3.1 billion square feet of federal buildings space—military bases, post offices, VA hospitals, Department of Energy (DOE) laboratories, courthouses—and the Nation's Federal energy intensive operations. (Energy-intensive operations include, for example, laboratories, check-processing facilities, and linear accelerators.) The Federal Government's actions—via leadership, awards, influence, and raw purchasing power—may well influence private-sector and state and local government decisions with respect to energy-related decisions, but any such "spillover" impact is not estimated in this GPRA process.

Finally, the question of attribution of impact must be addressed. The mission of FEMP is to assist the Department of Defense, GSA, and other Federal agencies in attaining legislative and executive order energy goals for those agencies. The analysis needs to determine how much of that goal achievement is attributable to FEMP. Very specifically, how much of the site energy-intensity reduction in Federal buildings and facilities, from FY 2005 to FY 2010, is attributable to the portfolio of FEMP activities funded between FY 2005 and FY 2010, assuming level funding? In the GPRA analysis, PNNL assumes that 50% of the progress is attributable to FEMP's leadership and to FEMP's diverse portfolio. The other 50% is attributable to conservation retrofit funding, awareness campaigns at other Federal agencies, as well as to the existence of appliance and equipment standards and general technological innovation.

The 50% estimate was originally derived from analysis performed in support of the Energy Savings Performance Contract alternative financing activity within FEMP.[1] An assessment of the likely agency markets for alternative-financing products from FEMP (both ESPC and Utility Programs) produced estimates of FEMP programmatic impact of 35% to 55%, with most of the remainder being attributed to the Army Corps' Huntsville ESPC operation. This estimate did *not* include the likely impacts of the rest of FEMP's portfolio—direct technical assistance, training, and information. Taking the lower-end estimate of 35% and including these other impacts, PNNL estimated that a reasonable impact was 50%.

Energy-Savings Calculation Mechanics

Actual historical and estimated future energy consumption are characterized in terms of fuel consumption (MMBtu or million Btu), fuel mix (the fractions of total fuel consumption by fuel type), and building floor space (ksf or thousand square feet). A critical derived figure is building energy intensity (MMBtu/ksf). The development of these measures is described in the sections that follow.

Historical Federal Agency Energy Consumption and Cost

Estimates of future Federal agency energy consumption start from the latest data available for actual energy consumption. For the analysis of impacts resulting from the FY 2005 Budget Request, the latest actual data were for FY 2002. These data were provided by the individual Federal agencies to McNeil Technologies, which has the responsibility for collecting and managing these data for FEMP. In turn, PNNL receives these data from McNeil. These data are eventually documented in the *Annual Report to Congress on Federal Government Energy Management and Conservation Programs*[2] for each fiscal year. As of February 2004, the most recent published version of this report covered fiscal year 2000 and was published December 13, 2002.

The historical data available for analysis are energy consumption (MMBtu) by fuel type and building floor space (ksf). These data are reported by each agency. The fuel type categories are electricity, fuel oil, natural gas, liquefied petroleum gas (lpg), coal, purchased steam, and "other." Building energy intensities (MMBtu/ksf) are calculated from these raw data.

Future Federal Agency Energy Consumption

Future Federal energy consumption was estimated by combining estimates of future building energy intensity, fuel mix, and building floor space. Total energy consumption (MMBtu) is the product of building energy intensity (MMBtu/ksf) and building floor space (ksf), as defined by Equation 1. Energy consumption by fuel type (MMBtu) is the

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[1] FEMP Fiscal Year 1999 ESPC Business Strategy Development Summary Report, K. McMordie-Stoughton and D. Hunt, Pacific Northwest National Laboratory, March 2000, PNNL-13204.
[2] Available on FEMP's Web site at http://www.eere.energy.gov/femp/aboutfemp/annual_reports/ann00_report.html

product of total energy consumption and fuel-mix fraction for each fuel type, as defined by Equation 2.

Total Energy = Building Energy Intensity * Building floor space   Eqn. 1.

Fuel Type "A" Energy = Total Energy * Fuel "A" Mix Fraction   Eqn. 2.

The Department of Defense (DOD), DOE, General Services Administration (GSA), United States Postal Service (USPS), and Veterans Affairs (VA) were selected for specific metric development because they are the five largest agencies measured by annual energy use, consuming nearly 90% of the Federal total in FY2002; DOD alone is nearly two-thirds of total Federal energy use (see **Figure 1**). Reduction in MMBtu/ksf from FY2000 through FY2010 was estimated for each of these five agencies and all other agencies (24 total) grouped together for standard buildings. Metrics for energy intensive operations were developed for the Federal government as a whole. The following subsections describe the development of building energy intensity, building floor space, and fuel-mix fraction assumptions. In addition, the resulting estimates of building energy intensity reductions are provided.

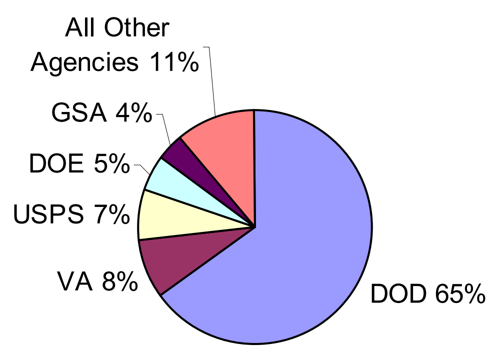

Figure 1. FY2002 Federal Agency Standard Building Energy Consumption

Building Energy Intensity

Estimates for agency-specific reductions in MMBtu/ksf by FY2010 relative to FY2000 were aggregated from estimates due to a) cost-effective retrofits of building energy systems, b) replacement of equipment upon failure (with generally more efficient equipment), c) cost-effective retrofits of central energy plants and thermal distribution systems (DOD, DOE, and VA only), d) construction of new housing (DOD only), and e) improvements in O&M practices. These five categories have differing assumptions, and the assumptions for each agency can be different within a particular category. The assumptions are discussed in the text below, and are based on literature referenced in the text. **Table 2** presents the output estimates of energy intensity reductions derived from the spreadsheet model by category and agency.

Table 2. Energy-Intensity Reduction Estimates

Estimated Reduction in MMBtu/ksf by 2010 from 2000						
	Agency					
Reduction Source	**DOD**	**DOE**	**GSA**	**USPS**	**VA**	**Other**
Building Retrofit	7	11	9	8	8	9
Replace on Failure	4	4	4	4	4	4
CEP and Dist Retrofit	2.5	2.5			2.5	
Improved O&M	3	6	2	2	4	3
New Housing	0.5					
Total	17	23.5	15	14	18.5	16
FY2000 MMBtu/ksf	105	249	67	74	168	115

The reduction in MMBtu/ksf for Federal agencies was based primarily on data developed in two PNNL reports, *Economic Energy Savings Potential in Federal Buildings*[3], and *An Assessment of Prospective FORSCOM Energy Intensities*[4]. The former was prepared for FEMP by D. Brown, J. Dirks, and D. Hunt and is available from PNNL's Web site at http://www.pnl.gov/main/publications/; the latter was prepared for the U.S. Army's Forces Command (FORSCOM) by D. Brown and J. Dirks.

The report for FEMP specifically examined the retrofit potential based on government financing for all government agencies, while the report for FORSCOM examined the retrofit potential for their facilities based on either government or alternative-financing mechanisms[5]. The report for FORSCOM also looked at the impacts of the natural turnover of HVAC and service hot water (SHW) equipment (called "replace on failure" in **Table 2**), improvements to central energy plants (CEPs, i.e., boilers and/or chillers) and thermal distribution systems, and housing privatization plans (demolition, renovation, and new construction).

FORSCOM facilities represent about 10% of total DOD floor space and have a mix of buildings types generally representative of DOD as a whole. In addition, the retrofit-estimating methodology was more robust than that used for the DOD sector in the FEMP report. Therefore, the FORSCOM results were used as the basis for estimating retrofit potential for DOD, while the FEMP results were used as the basis for other agencies.

[3] D.R. Brown, J.A. Dirks, and D.M. Hunt. 2000. *Economic Energy Savings Potential in Federal Buildings*. PNNL-13332. Pacific Northwest National Laboratory. Richland, Washington.

[4] Distribution of the full report is limited by FORSCOM. The following paper, based on the full report, is publicly available. D.R. Brown and J.A. Dirks. 2002. "Prospective FORSCOM Energy Intensities." *Proceedings of the 25th World Energy Engineering Conference*. Association of Energy Engineers. Atlanta, Georgia.

[5] Alternative financing includes energy-saving performance contracts (ESPC) and utility energy service contracts (UESC).

The estimated retrofit potential for non-DOD agencies from the FEMP report was reduced by one-third to reflect alternative financing rather than government financing (appropriations). This factor is driven by the higher interest rates and shorter financing periods typically seen for alternative financing and is based on work by J. Dirks, D. Brown, and J. Currie of PNNL[6]. Finally, 50% of the estimated potential via alternative financing was assumed captured by FY2010. This will approximately occur if the rate of annual alternative-financing investment from FY1998 through FY2000 continues through FY2010, with the same ratio of energy savings per dollar invested as seen in FY1998 through FY2000.

Replacement of HVAC and SHW equipment occurs continuously as equipment ages, fails, and must be replaced. In general, the efficiency of HVAC and SHW equipment has substantially improved because of technology advances, stimulated in part by stricter equipment and appliance standards at the national level. Other factors include building energy codes and the forces of technological innovation. As a result, replacement equipment will usually consume less energy than the equipment being replaced; and, in some cases, much less energy (refrigerators and chillers, for example). The estimated energy-intensity reduction from this mechanism was about 4 MMBtu/ksf in the FORSCOM study; the estimated impact for civilian agencies was judged by PNNL to be the same, since the phenomenon of improving energy efficiency in new equipment and appliances is economy-wide and not restricted to just DOD.

DOD sites often have large CEPs and accompanying thermal distribution systems. Results from the FORSCOM report indicated potential energy savings equivalent to a reduction in building energy intensity of 5 MMBtu/ksf. Again, it is unlikely that 100% of the potential will be captured. A 50% capture fraction was assumed to be consistent with the building retrofit capture fraction assumption. Among the four civilian agencies considered explicitly, only DOE and VA have a significant number of sites with CEPs, so this projected savings was only applied to these two agencies, in addition to DOD.

The estimated decrease in MMBtu/ksf from improved O&M practices was developed from data presented in *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems* by S. Nadel (et al) of American Council for an Energy Efficient Economy (ACEEE); and *Energy and Comfort Benefits of Continuous Commissioning in Buildings* by D. Claridge (et al) of Texas A&M University. Specifically, Nadel estimated cost-effective energy savings via improved O&M practices to be between 5% and 15% of existing energy consumption, with a maximum penetration rate of 50%. To be conservative, PNNL used a penetration rate of 25% for the FEMP GPRA analysis. Thus, starting from an average potential of 10%, the estimated savings from improved O&M practices was set equal to 2.5% of energy consumption in FY2000.

[6] J.A. Dirks, D.R. Brown, and J.W. Currie. 1999. Sensitivity of ESPC Projects to Changes in Interest Rates and Energy Prices. Pacific Northwest National Laboratory. Richland, Washington. An informal letter report from PNNL to FEMP.

DOD is unique among the Federal agencies with respect to the housing stock it manages for military personnel and their families. About 90% of federal housing stock, or about 600 million square feet, resides in the military. All three branches of the military are currently privatizing a significant portion of their housing stock. Privatization plans, besides transferring ownership, call for significant demolition, new construction, and renovation. The impact of these housing-stock changes was estimated (in the FORSCOM report) to reduce FORSCOM's overall building energy intensity by about 3 MMBtu/ksf. This figure was reduced to 0.5 MMBtu/ksf for DOD, as a whole, because the energy impacts of housing privatization are concentrated within FORSCOM.

The FY2010 building energy-intensity calculations are defined by Equation 3 for standard buildings. To calculate energy intensity for FY2010, the estimated reductions in MMBtu/ksf shown in **Table 2** are subtracted from the actual energy intensities for each agency in FY2000. Although actual FY2002 energy consumption data are now available, the estimated energy intensities for FY2010 are based on FY2000 to be consistent with the references (reports for FEMP and FORSCOM described above) supporting the figures in **Table 2**. As described earlier, the FY2010 energy intensity for energy-intensive operations was set at the value that exactly meets the energy-intensity goal for these types of facilities.

Building Energy Intensity in FY2010 =
Building Energy Intensity in FY2000 –
Building Energy Intensity Reduction Estimate Eqn. 3

Energy intensities for years between FY2002 and FY2010 were geometrically interpolated between these two endpoints. Energy intensities beyond FY2010 were assumed to continue declining, with each year 1% less than the previous year. This is a conservative assumption compared to the average compounded rate of decline from 1985 through 2002, which was 1.7%.

Building Floor Space

Future building floor space was set equal to the FY2002 value, i.e. no change in floor space was assumed through FY2030. Note, however, that floor space has been increasing slowly since FY1997 at a rate of about 0.5% per year, after declining from FY1985 to FY1997. The decline through FY1997 was driven mostly by reductions in DOD, while the increase since FY1997 is mostly attributable to USPS. It is not clear whether an increase or decrease in floor space is more likely during the next 10 years, let alone the next 30 years; therefore, floor space was assumed to remain constant for the duration of the analysis period.

Fuel Mix

Since FY1985, total site use of coal and fuel oil has declined significantly, while the use of electricity has remained nearly constant and the use of natural gas has declined slightly. As a consequence of these changes, the fractions of fuel use associated with electricity (and to a lesser extent, natural gas) have increased over time (See **Figure 2**).

EIA forecasts from the *Annual Energy Outlook 2003* suggest that this trend will continue, with site use of electricity increasing relative to other energy forms.

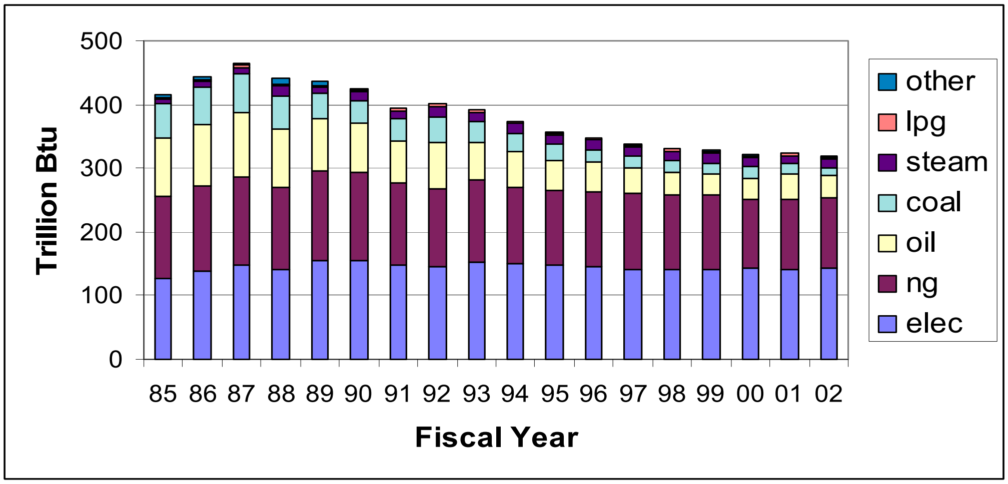

Figure 2. Historical Energy Use in Standard Federal Buildings

Changes in the forecast fuel mix for the commercial sector from EIA's *Annual Energy Outlook 2003* were applied to the actual Federal fuel mixes in FY2002 to estimate future federal fuel mixes. Projected changes for the commercial-sector fuel mix were first normalized relative to the existing commercial sector fuel mix in 2002. For example, the normalized electricity fraction in the commercial sector grew from 1.0 (by definition) in 2002 to 1.13 in 2030. In contrast, the normalized natural gas fraction in the commercial sector fell from 1.0 in 2002 to 0.92 in 2030. The normalized fuel fractions for each fuel and each year were multiplied by the actual Federal fuel fractions in 2002 for each agency or agency group to estimate future Federal fuel mixes.

This procedure was applied to standard buildings, but not to energy-intensive operations. There, it was not so clear what sector (commercial or industrial) would better represent energy-intensive operations or whether the year-to-year volatility in reported data for energy-intensive operations would invalidate the refined approach. Instead, future fuel mixes for energy-intensive operations were assumed to remain as they were in FY2002.

Federal Agency Energy-Consumption Baseline

The baseline Federal agency energy consumption is the estimated Federal agency energy consumption in FY2004. FY2005 is the first possible year that could be affected by the FY2005 budget, so FY2004 is the logical baseline year. As previously described, the latest actual data are from FY2002. Energy consumption by fuel type is estimated for each year after FY2002, including the FY2004 baseline year, via the process described above in the section on Future Federal Agency Energy Consumption.

Future Federal Agency Energy Savings

Annual energy savings were calculated by subtracting the estimated energy consumption in FY2004 from the estimated energy consumption for FY2005 and each following year. These calculations were done for each fuel type. Implicitly, if not for activities conducted by FEMP and the Federal agencies, future energy consumption would remain as estimated for FY2004, and there would be no energy savings. Energy savings were summed across agencies and fuel types to determine total energy savings. Equations 4-6 define these calculations.

Fuel Type A Energy Savings for Agency B in FY20XX =
Fuel Type A Energy Consumption for Agency B in FY20XX –
Fuel Type A Energy Consumption for Agency B in FY2004 Eqn. 4.

Fuel Type A Federal Energy Savings in FY20XX=
Σ Fuel Type A Energy Savings across all Agencies in FY20xx Eqn. 5.

Federal Energy Savings in FY20XX =
Σ Fuel Type A Federal Energy Savings across all Fuel Types Eqn. 6.

Energy savings by fuel type, measured in MMBtu, were converted to alternative units for reporting requirements via the conversion factors listed in **Table 3**.

Table 3. Energy Conversion Factors[7]

Fuel Oil: 5.825 MMBtu/barrel
Natural Gas: 1.027 MMBtu/1000 cubic feet
Coal: 22.489 MMBtu/short ton
Electricity: 3.412 MMBtu/MWh
LPG: 3.603 MMBtu/barrel

Energy-Savings Results

Estimated annual and cumulative energy savings attributable to FEMP resulting from the FY 2005 Budget Request are summarized in **Table 4** and **Table 5**.

[7] Source: Performance Planning Guidance (GPRA Data Call) FY2004-2008 Budget Cycle-Draft. April 1, 2002. U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy.

Table 4. Annual Energy Metrics for Federal Standard Buildings and Energy-Intensive Operations (FY 2005 Budget Request)

Year	Total Site Energy Displaced (TBtu)	Direct Electricity Displaced (billion kWh)	Direct Natural Gas Displaced (billion CF)	Direct Petroleum Displaced (million barrels)	Direct Coal Displaced (million short tons)	Direct Biomass Displaced (TBtu)	Direct Energy Displaced from Feedstocks (TBtu)	Direct Energy Displaced from Wastes (TBtu)	Other Direct Energy Displaced (TBtu)
2005	3.28	0.355	1.40	0.0754	0.0060	0	0	0	0
2006	6.49	0.695	2.74	0.1570	0.0150	0	0	0	0
2007	9.65	0.973	4.04	0.2496	0.0294	0	0	0	0
2008	12.74	1.234	5.36	0.3426	0.0425	0	0	0	0
2009	15.78	1.496	6.65	0.4244	0.0573	0	0	0	0
2010	18.76	1.758	7.97	0.5041	0.0688	0	0	0	0
2015	26.82	2.256	11.55	0.8070	0.1071	0	0	0	0
2020	34.48	2.894	14.40	1.0972	0.1438	0	0	0	0
2025	41.77	3.501	17.19	1.3532	0.1806	0	0	0	0
2030	48.70	4.105	19.87	1.5728	0.2163	0	0	0	0

Table 5. Cumulative Energy Metrics for Federal Standard Buildings and Energy-Intensive Operations (FY 2005 Budget Request)

Year	Total Site Energy Displaced (TBtu)	Direct Electricity Displaced (billion kWh)	Direct Natural Gas Displaced (billion CF)	Direct Petroleum Displaced (million barrels)	Direct Coal Displaced (million short tons)	Direct Biomass Displaced (TBtu)	Direct Energy Displaced from Feedstocks (TBtu)	Direct Energy Displaced from Wastes (TBtu)	Other Direct Energy Displaced (TBtu)
2005	3.28	0.35	1.40	0.08	0.01	0	0	0	0
2006	9.77	1.05	4.14	0.23	0.02	0	0	0	0
2007	19.41	2.02	8.18	0.48	0.05	0	0	0	0
2008	32.16	3.26	13.54	0.82	0.09	0	0	0	0
2009	47.94	4.75	20.19	1.25	0.15	0	0	0	0
2010	66.70	6.51	28.16	1.75	0.22	0	0	0	0
2015	184.84	16.74	79.17	5.18	0.68	0	0	0	0
2020	342.08	29.93	145.65	10.08	1.32	0	0	0	0
2025	536.50	46.25	225.92	16.35	2.15	0	0	0	0
2030	766.29	65.57	319.97	23.78	3.17	0	0	0	0

Appendix F – GPRA05 Geothermal Technologies Program Documentation

Description of Assumptions that Support the GPRA 05 Benefits Analysis

The primary goal of the Geothermal Technologies Program is to reduce the cost of geothermal generation technologies, including both conventional and enhanced geothermal systems (EGS). Estimating the GPRA benefits involves projecting the market share for these technologies based on their economic and environmental characteristics.

Market Segments

Geothermal power is expected to penetrate in two market segments: the least-cost power market and the green power market. Only centrally located geothermal power plants were considered, although there is emerging industry interest in distributed applications, and there is a new DOE program to explore small-scale modular geothermal plant technology development (<5 MW).

- Least-Cost Power
  NEMS-GPRA05 and MARKAL-GPRA05 were run to estimate market penetration into the competitive bulk power marketplace for geothermal power technologies. The program goals for geothermal technology improvements are modeled directly by incorporating the capital and operation and maintenance (O&M) cost reductions. The models also take into account site availability and maximum development per site per year for conventional and EGS geothermal capacity. The conventional geothermal characteristics modeled are from the EPRI/DOE *Renewable Energy Technology Characterizations*[1] report. The EGS characteristics were developed by Princeton Energy Resources International (PERI) in 2003.

- Green Power
  Flash, binary, and EGS technologies were all modeled as potential geothermal power plants that could be installed to meet the emerging green power market. Flash and binary technologies compete well within the green power market, with flash technology out-gaining binary due to its more attractive cost curve. EGS technologies have significant cost penalties that restrict capacity additions until after 2015, and even then only a very limited amount of EGS power is projected to be built to meet green power demand. Although geothermal plants were limited to the western portion of the United States, they were typically one of the least-expensive options, leading to significant penetration in those two regions. The projections for green power geothermal installations were incorporated into the NEMS-GPRA05 and MARKAL-GPRA05 models as planned capacity additions.

[1] Renewable Energy Technology Characterizations, EPRI /DOE TR-109496, 1997.

Detailed Input and Methodology Information

NEMS-GPRA05

The NEMS-GPRA05 electricity-sector module performs an economic analysis of alternative technologies in each of 13 regions. Within each region, new capacity is selected based on its relative capital and operating costs, its operating performance (i.e. availability), the regional load requirements, and existing capacity resources. Geothermal capacity is treated in a unique manner due to the specific geographic nature of the resources. The model characterizes 51 individual sites of known hydrothermal geothermal resources, each with a set of capital and O&M costs. For the Program Case, three EGS sites in each of three regions were substituted for the most expensive hydrothermal sites in those regions.

Conventional Geothermal

Figure 1 illustrates the supply curve of the hydrothermal sites in the Northwest United States in 2006 and 2020 that can be developed in each of those years in NEMS-GPRA05. These curves reflect the GPRA cost reductions, as well as the financing assumptions from the *Annual Energy Outlook 2003* (*AEO03*) Reference Case, and the limit of developing only 100 MW at a site each year. The limit of 100 MW development per site per year is an increase from the *AEO03* assumption of only 25 MW or 50 MW (depending on year). The limit change is made to reflect the program's efforts to reduce the risk associated with new geothermal development. The lowest part of the curve is not depicted for 2020, because it represents a portion of the capacity already developed.

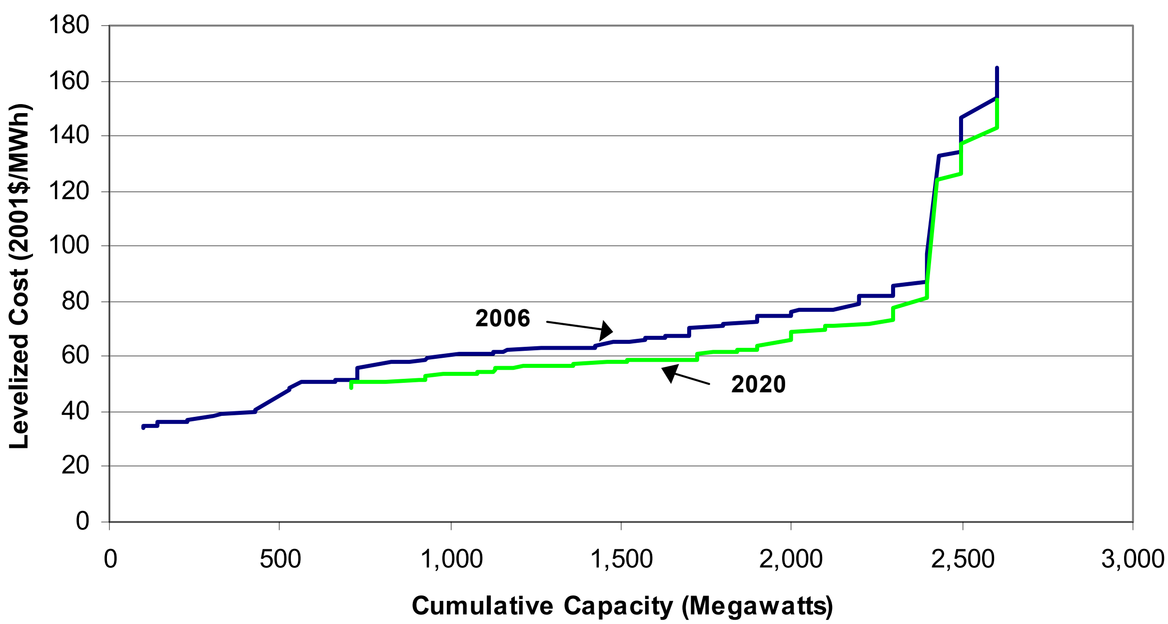

Figure 1. Geothermal Supply Curve – Northwest Region

Roughly 10 GW of hydrothermal resource in the Northwest and 23 GW in the lower 48 states is represented within NEMS-GPRA05. With the GPRA Base Case assumptions, much of this resource would be quite expensive to develop; today, an estimated 5 GW might be available at 6 cents per kWh.

Enhanced Geothermal Systems

Characteristics for EGS systems were also provided. Nine new EGS sites, were substituted for the three most expensive hydrothermal sites in the western regions: Northwest Power Pool (NWP, Region 11), Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA, Region 12), and California (CA, Region 13). Each site represents a Type of EGS resource:

Type I. A site where EGS would be used to improve an existing commercial hydrothermal reservoir.

Type II. A site where EGS would work to develop economic power from identified sites with sub-commercial hydrothermal features.

Type III. A site where EGS would be used as a longer-term strategy to develop power systems in volumes of rock that have not been identified as hydrothermal prospects.

Similar to the conventional sites, each geothermal site is further specified in four stages of increasing costs (**Table 1**).

Table 1. EGS Site Characterization for NEMS-GPRA05

		Potential Capacity 1 (MW)	Potential Capacity 2 (MW)	Potential Capacity 3 (MW)	Potential Capacity 4 (MW)	Capacity Factor
Region 11	EGS Type I	550	550	550	550	0.9
	EGS Type II	2500	2500	2500	2500	0.9
	EGS Type III	5000	5000	5000	5000	0.9
Region 12	EGS Type I	0	0	0	0	0.9
	EGS Type II	1250	1250	1250	1250	0.9
	EGS Type III	5000	5000	5000	5000	0.9
Region 13	EGS Type I	300	300	300	300	0.9
	EGS Type II	2500	2500	2500	2500	0.9
	EGS Type III	5000	5000	5000	5000	0.9

Capital and O&M costs were provided for the initial development at each site and were the same for all regions. The EGS and conventional costs are shown below in 2001 dollars (**Table 2**).

Table 2. Geothermal Characteristics for NEMS-GPRA05

	2005	2010	2015	2020	2025
Capital Cost (2001$/kW)					
Flash	1,342	1,282	1,232	1,181	1,147
Binary	2,141	2,013	1,883	1,758	1,691
EGS I	2,400	2,132	1,864	1,596	1,328
EGS II	2,760	2,452	2,144	1,835	1,527
EGS III	3,120	2,772	2,423	2,075	1,726
Total O&M Costs (2001$/kW-yr)					
Flash	80.3	71.2	66.6	62.5	60.7
Binary	84.3	71.7	63.9	56.3	55.3
EGS I	150.0	132.0	114.0	96.0	78.0
EGS II	172.5	151.8	131.1	110.4	89.7
EGS III	195.0	171.6	148.2	124.8	101.4

MARKAL-GPRA05

The geothermal technologies represented in MARKAL-GPRA05 reflect the program goals for both conventional systems and EGS. For conventional geothermal systems, the capital and operating and maintenance costs were changed to reflect program goals. However, EGS represents a new geothermal resource not previously represented in the MARKAL-GPRA05 model. The program identified three separate types of potential geothermal reservoirs, as discussed above.

Due to program activities, the capital and O&M costs of EGS systems are projected to decline over time. **Table 3** shows the estimated capital and O&M costs for the three types of EGS systems for 2000 and 2050.

Table 3: EGS Generation Assumptions for MARKAL-GPRA05

EGS Type	Projected Resource MWe	2000 Cost Capital Cost 01$/kW	2000 Cost O&M 01$/kW/yr	2050 Cost Capital Cost 01$/kW	2050 Cost O&M 01$/kW/yr
I	**3,400**	2,448	153	934	50
II	**25,000**	2,815	176	1,074	58
III	**60,000**	3,182	199	1,214	66

The EGS sites projected under the program are grouped into a set of supply steps and the discount rate of these technologies is set at 8% (instead of 10% for the industrial average) to reflect the accelerated depreciation schedule permitted by the IRS for renewable generation technologies. The EGS systems are modeled as centralized base-load generation.

Geothermal plants compete directly with fossil fuel-based plants for both electricity generation and meeting peak power requirements. In MARKAL-GPRA05, EGS becomes more competitive as its higher capital cost is offset by increased fossil fuel costs, which increase as demand increases.

Green Power Market Model

PERI used the Green Power Market model to project regional green power additions (**Table 4**). These capacity additions are used by NEMS-GPRA05 and MARKAL-GPRA05 as planned new capacity or minimum capacity additions.

Table 4. Incremental Green Power Geothermal Capacity Additions (MW)

	2004-2008	2009-2010	2011-2015	2016-2020	2021-2025	2004-2020
NWPP	1	26	60	54	29	170
RA	3	24	50	36	23	136
CNV	0	37	94	100	48	280
Total	4	87	204	190	100	585

Appendix G – GPRA05 Hydrogen, Fuel Cells, and Infrastructure Technologies Program Documentation

Fuel Cell Vehicles

Fuel cell vehicle (FCV) attributes were based on the Hydrogen, Fuel Cells, and Infrastructure Technologies (HFCIT) program goals, discussions with HFCIT program managers, and technical analysis by contractors (Ref. 1). Because the two models (NEMS-GPRA05 and MARKAL-GPRA05) that generate GPRA results require different levels of detail, the technical characterizations were provided in two parts: one for input to NEMS-GPRA05 and one for input to MARKAL-GPRA05. The discussion of the light-vehicle (LV) characterization is divided into two parts below.

Input to NEMS-GPRA05

Table 1 contains vehicle attributes for FCVs operating on hydrogen (H2) delivered to the FCV as H2 (Fuel Cell Hydrogen), and FCVs operating on H2 reformed from onboard gasoline (Fuel Cell Gasoline). These advanced technologies may be used in cars and light trucks (LTs). Attributes are provided for the two technologies in up to two car size classes and three LT classes. The attributes are for new vehicles in the year listed. The attributes include the following:

- Vehicle Price
- Range
- Maintenance Cost
- Acceleration
- Top Speed
- Luggage Space
- Fuel Economy

The attributes for the two technologies are provided as ratios to the vehicle attributes of conventional vehicles.

The attributes of the two advanced technologies vary over time. The two technologies are at different stages of technology development and, thus, are expected to penetrate the LV market at different times. In fact, FCVs operating on gasoline are expected to enter the new vehicle market first, but be out of it by 2030. The attributes were implemented in NEMS-GPRA05 as step-functions over time.

Using the program's vehicle-attribute characterization provided in **Table 1**, attributes were assigned to the six car size classes and six LT classes used in NEMS-GPRA05. The results are shown in **Table 2**.

Input to MARKAL-GPRA05

The MARKAL-GPRA05 model provides benefits estimates for the GPRA analysis out to 2050. The model does not require LV characterization at the level of detail that NEMS-GPRA05 does. There is no disaggregation of cars and LTs into size classes, and only cost and fuel economy ratios are required. **Table 3** presents the LV characterization input to MARKAL-GPRA05.

Table 1. Attributes of Fuel Cell Vehicles Relative to Conventional Vehicles

	SMALL CARS			LARGE CARS		
Fuel Cell Hydrogen	**2018**	**2020**	**2025**	**2016**	**2020**	**2025**
Vehicle Price	1.050	1.030-1.040	1.020-1.037	1.100	1.050	1.025-1.029
Range	1.00	1.00	1.00	1.00	1.00	1.00
Maintenance Cost	1.05	1.00	0.93	1.05	1.00	0.93
Acceleration	1.10	1.10	1.10	1.00	1.00	1.10
Top Speed	0.95	0.95	0.95	0.75	0.90	0.95
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy*	2.50	2.70	3.00	2.20	2.50	3.00
Fuel Cell Gasoline				**2010**	**2020**	**2025**
Vehicle Price				1.300	1.200	1.150
Range				1.00	1.00	1.00
Maintenance Cost				1.05	1.00	0.93
Acceleration				1.00	1.00	1.00
Top Speed				1.00	1.00	1.00
Luggage Space				0.90	1.00	1.00
Fuel Economy*				1.50	1.80	2.00

	MINI-VAN			SUV				CARGO TRUCK		
Fuel Cell Hydrogen	**2014**	**2020**	**2025**	**2012**	**2015**	**2020**	**2025**	**2012**	**2020**	**2025**
Vehicle Price	1.200	1.035	1.031	1.250	1.100	1.030-1.035	1.030-1.033	1.250	1.04-1.050	1.038-1.045
Range	0.90	1.00	1.00	0.90	1.00	1.00	1.00	0.90	1.00	1.00
Maintenance Cost	1.10	1.00	0.95	1.05	1.05	1.00	1.00	1.05	1.00	0.93
Acceleration	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.00	1.00	1.00
Top Speed	0.90	0.95	0.95	0.90	0.90	0.95	0.95	0.90	0.90	0.95
Luggage Space	0.90	1.00	1.00	0.90	1.00	1.00	1.00	0.80	1.00	1.00
Fuel Economy*	2.00	2.50	3.00	2.00	2.30	2.50	2.50	2.00	2.50	3.00
Fuel Cell Gasoline	**2010**	**2020**		**2010**	**2020**					
Vehicle Price	1.300	1.200		1.300	1.200					
Range	1.00	1.00		1.00	1.00					
Maintenance Cost	1.05	1.00		1.05	1.00					
Acceleration	1.00	1.00		1.00	1.00					
Top Speed	1.00	1.00		1.00	1.00					
Luggage Space	0.90	1.00		0.90	1.00					
Fuel Economy*	1.40	1.80		1.40	1.80					

*** Gasoline equivalent**

Table 2. Vehicle Cost Ratios by Car and LT Class Size

Fuel Cell Hydrogen

Small cars	2018	2020	2025
2-seater	1.05	1.03	1.025
Mini-compact	1.05	1.03	1.020
Subcompact	1.05	1.04	1.037
Compact	1.05	1.04	1.037

Large Cars	2016	2020	2025
Midsize	1.1	1.05	1.029
Large	1.1	1.05	1.025

Mini Van	2014	2020	2025
Min-van	1.2	1.035	1.031

Fuel Cell Gasoline[1]

Large Cars	2010	2020	2025
Midsize	1.3	1.2	1.015
Large	1.3	1.2	1.015

Mini Van	2010	2020
Min-van	1.3	1.2

Fuel Cell Hydrogen

SUVs	2012	2015	2020	2025
Small	1.25	1.1	1.035	1.033
Large	1.25	1.1	1.03	1.03

Cargo Truck	2012	2020	2025
Large Van	1.25	1.035	1.032
Small Pickup	1.25	1.03	1.045
Large Pick up	1.25	1.04	1.038

Fuel Cell Gasoline

SUVs	2010	2020
Small	1.3	1.2
Large	1.3	1.2

[1] No small fuel cell gasoline cars were characterized.

Table 3. Light-Vehicle Characteristics for Analysis of HFCIT Program Using MARKAL-GPRA05 Model

Vehicle Type	Technology	Ratio	2010	2015	2020	2025	2030	2040	2050
Car	Fuel Cell Gasoline	Cost	1.30		1.20	1.15			
		MPG*	1.50		1.80	2.00			
	Fuel Cell Hydrogen	Cost		1.10	1.05	1.05	1.05	1.05	1.05
		MPG*		2.20	2.50	3.00	3.20	3.40	3.40
LT	Fuel Cell Gasoline	Cost	1.30		1.20				
		MPG*	1.40		1.80				
	Fuel Cell Hydrogen	Cost	1.25	1.10	1.05	1.05	1.05	1.05	1.05
		MPG*	2.00	2.30	2.50	3.00	3.20	3.40	3.40

* Gasoline equivalent

Stationary Fuel Cells

Tables 4 and 5 present the assumptions used in the stationary fuel cell characterization for GPRA05. The assumptions for distributed PEM fuel cells are based on the program's multiyear program plan (MYPP) (Ref 1.). Capital costs and efficiencies were provided in the MYPP for the years 2003, 2005, and 2010. The MYPP costs are assumed to be in year 2003 dollars, because the report was written in 2003 and no cost year is provided in the document. No values were listed for maintenance costs, so the AEO2003 values are used. Values were estimated to 2020. These values were then held constant post-2020 to 2050.

The AEO2003 values are used for the GPRA05 Baseline and are provided in year 2000 dollars.

There are no changes from the Baseline for large central-station fuel cells.

Table 4. 200 kW Commercial Combined Heat and Power Systems

Baseline AEO2003 Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2000 $/kW)	Maint. Cost (2000$/kW-yr)
1993	2001	.729	0.360	0.577	3674	87.0
2002	2005	.731	0.378	0.567	3282	84.5
2006	2009	.733	0.401	0.554	2834	81.6
2010	2014	.736	0.430	0.536	2329	78.3
2015	2019	.740	0.473	0.506	1713	74.3
2020	2025	.741	0.495	0.488	1433	72.5

GPRA Program Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2003 $/kW)[2]	Maint. Cost (2000$/kW-yr)
2002	2004	.700	0.300	0.571	2500	84.5
2005	2009	.750	0.320	0.632	1250	81.6
2010	2014	.800	0.400	0.667	750	78.3
2015	2019	.800	0.400	0.667	750	74.3
2020	2025	.800	0.400	0.667	750	72.5

Table 5. 5 kW Residential Combined Heat and Power Systems

Baseline AEO2003 Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2000 $/kW)	Maint. Cost (2000$/kW-yr)
1993	2001	.729	0.360	0.577	3674	87.0
2002	2005	.731	0.378	0.567	3282	84.5
2006	2009	.733	0.401	0.554	2834	81.6
2010	2014	.736	0.430	0.536	2329	78.3
2015	2025	.740	0.473	0.506	1713	74.3

GPRA Program Assumptions

First Year	Last Year	CHP System Efficiency	Electrical Efficiency	Thermal Recovery Efficiency	Equip. Cost (2003 $/kW)[2]	Maint. Cost (2000$/kW-yr)
2002	2004	.700	0.300	0.571	3000	84.5
2005	2009	.750	0.320	0.632	1500	81.6
2010	2014	.800	0.350	0.692	1000	78.3
2015	2025	.800	0.350	0.692	1000	74.3

[2] Source: HFCIT Program's multiyear program plan. Costs are assumed to be in year 2003 dollars.

Hydrogen Price

In NEMS-GPRA05, the hydrogen price is computed as a function of natural gas prices because the model does not represent hydrogen production explicitly. Based on the MYPP, the hydrogen-conversion process is assumed to be 75% efficient and yield a hydrogen price of $1.50 (excluding taxes) when the natural gas price is $4 per MMBtu (Ref. 1).

In MARKAL-GPRA05, hydrogen cost estimates were developed for H2 produced using several centralized production processes (coal, natural gas, biomass, and electrolysis) as well as by distributed natural gas. A discussion of these estimates can be found in **Chapter 5** of the GPRA FY2005 Benefits Report, as well as in Reference 2.

Hydrogen Supply Technology Assumptions

Table 6 shows projected hydrogen costs by cost component for the Hydrogen Scenario, as presented in Reference 2. Please note that the projected costs may not match HFCITP goals due to differences in discount rates, distribution costs, taxes, and delivered feedstock costs.

Table 6. Hydrogen Production Costs by Technology and Component

Central Coal

Unit Costs (2001$/gge)	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs			$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
O&M			$0.27	$0.27	$0.27	$0.27	$0.27	$0.27
Feedstock Costs			$0.22	$0.24	$0.25	$0.27	$0.27	$0.28
Plant Gate			**$0.97**	**$0.99**	**$0.99**	**$1.01**	**$1.02**	**$1.02**
Distribution, Storage & Tax			$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Total			**$2.00**	**$2.02**	**$2.03**	**$2.04**	**$2.05**	**$2.06**

Distributed Natural Gas Reformer

Unit Costs (2001$/gge)	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs	$0.73	$0.42	$0.42	$0.42	$0.42			
O&M	$0.53	$0.54	$0.53	$0.54	$0.54			
Feedstock Costs	$0.79	$0.83	$0.84	$0.90	$0.93			
Plant Gate	**$2.05**	**$1.79**	**$1.80**	**$1.86**	**$1.89**			
Tax	$0.38	$0.38	$0.38	$0.38	$0.38			
Total	**$2.43**	**$2.17**	**$2.17**	**$2.24**	**$2.27**			

Central Natural Gas Reformer

Unit Costs (2001$/gge)	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs			$0.15	$0.15	$0.15	$0.15	$0.15	
O&M			$0.08	$0.08	$0.08	$0.08	$0.08	
Feedstock Costs			$0.80	$0.86	$0.89	$0.93	$0.97	
Plant Gate			**$1.04**	**$1.10**	**$1.13**	**$1.17**	**$1.21**	
Distribution, Storage & Tax			$1.03	$1.03	$1.03	$1.03	$1.03	
Total			**$2.07**	**$2.13**	**$2.16**	**$2.20**	**$2.24**	

Central Biomass

Unit Costs (2001$/gge)	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs		$1.16	$1.02	$0.98	$0.96	$0.95	$0.95	$0.95
O&M		$0.34	$0.31	$0.31	$0.31	$0.31	$0.31	$0.31
Feedstock Costs		$0.35	$0.32	$0.32	$0.32	$0.32	$0.32	$0.32
Plant Gate		**$1.85**	**$1.65**	**$1.61**	**$1.59**	**$1.58**	**$1.58**	**$1.58**
Distribution & Storage*		$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65
Total		**$2.50**	**$2.31**	**$2.26**	**$2.25**	**$2.24**	**$2.23**	**$2.23**

Central Electrolytic Production**

Unit Costs (2001$/gge)	2015	2020	2025	2030	2035	2040	2045	2050
Capital Costs		$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11
O&M		$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
Feedstock Costs		$2.06	$2.02	$1.99	$2.31	$2.30	$2.21	$1.87
Plant Gate		**$2.37**	**$2.32**	**$2.30**	**$2.61**	**$2.60**	**$2.52**	**$2.17**
Distribution, Storage & Tax		$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Total		**$3.41**	**$3.36**	**$3.33**	**$3.64**	**$3.64**	**$3.55**	**$3.20**

* Note: Hydrogen produced from biomass was assumed to receive preferential tax treatment.

** Central electrolytic production technologies did not penetrate in the Hydrogen Scenario case. The above costs are based on a separate model run where this technology was required to produce.

Hydrogen Availability

In NEMS-GPRA05, an availability factor for hydrogen refueling stations is required. The program provided the assumptions in **Table 7**. MARKAL-GPRA05 does not require or use this availability factor.

Table 7. Hydrogen Fuel Availability at US Stations (%)

	2005	2010	2015	2020	2025	2030	2035	2040
Hydrogen availability	0	0	0	10	25	30	40	50

References

1. “Hydrogen, Fuel Cells & Infrastructure Technologies Program: Multi-Year Research, Development and Demonstration Plan” (Draft), U.S. Department of Energy, Energy Efficiency and Renewable energy (June 3, 2003).

2. P. Friley, “Benefit Estimation In MARKAL” (2004).

Appendix H – GPRA05 Industrial Technologies Program Documentation

The information provided in this report is based on the Industrial Technologies Program (ITP) report of the GPRA05 process, “GPRA05 Quality Metrics – Methodology and Results,” Energetics, Inc., March 11, 2004. The report includes additional methodological details and the actual off-line energy savings results submitted to the Office of Energy Efficiency and Renewable Energy (EERE).

Program Content

The GPRA05 calculation of future program impacts was performed separately for each planning unit and summed to produce the total ITP program impact. Within planning units, impacts were calculated differently for R&D planning units than for Technical Assistance planning units. Impacts for R&D planning units were calculated at the project level using a uniform methodology embodied in a spreadsheet-based computer tool called the Technology Impact Projections Model. Impacts for Industrial Assessment Center (IAC) and Best Practices planning units were calculated for subprogram element activities using historical data, estimates, and assumptions documented in tabular format; and summed to produce the planning unit impacts. ITP’s subprogram structure includes:

A. R&D Planning Units

1. Aluminum Industry Vision
2. Chemicals Industry Vision
3. Forest Products Industry Vision
4. Glass Industry Vision
5. Metal-Casting Industry Vision
6. Steel Industry Vision
7. Mining Industry Vision
8. Supporting Industry Vision
9. Industrial Materials Crosscut
10. Sensors and Automation Crosscut
11. Combustion Crosscut

B. Technical Assistance Planning Units

1. Industrial Assessment Center (IAC) Program
2. Best Practices Program

Target Markets – Base Case

A. Target Market Description

Advanced industrial energy efficiency technologies under development with program support will enter a variety of specialized markets for production equipment, plant energy conversion, distribution, heat recovery, and waste-reduction equipment. Underlying fuel prices, the electricity generation and distribution fuel mix and heat rates, and sector economic growth rates —which were used in the NEMS-GPRA05 runs that produced the ultimate results from ITP's energy-savings inputs—were consistent with the reference case in the Department of Energy's (DOE) *2003 Annual Energy Outlook*. ITP's off-line calculation of fuel and electricity savings for individual projects and program-element activities did not refer explicitly to macro-baseline quantities, except that a unique market growth rate was specified in each the 188 Technology Impact Projections Model runs. This permitted the analysts to differentiate among highly varied market outlooks in the various industries. The range of these annual economic growth rates was from 0% to 2.5%, with an average close to 1%.

Due to differences in the analytical framework of the NEMS-GPRA05 model and ITP's bottom-up energy-savings projection methodology, it was not possible to definitively match those models' base-case assumptions with the implicit base case in the GPRA study. NEMS-GPRA05 addresses the entire industry group in a top-down manner, assigning energy intensities to a comprehensive set of activities to project total industry energy use under alternative assumptions. The bottom-up ITP GPRA study specified the unit energy savings of a particular set of 188 advanced technologies, each in comparison to a best-available commercial technology alternative. ITP GPRA savings are only those savings attributable to these technologies in their primary intended markets.

The target market for each of 188 R&D technologies included in the ITP study was described qualitatively and quantitatively in a spreadsheet-based Technology Impact Projections Model run. The technologies were grouped based on common production activity Impact Targets. This was done to facilitate the identification of potentially overlapping markets; where potentially overlapping markets were found, either the market was split between the two competing technologies or only one spreadsheet model run was used to represent both technologies. Markets were defined in terms of the total number of technology units potentially in use at the year of introduction. This number was reduced to the fraction of those units considered technically and economically accessible, and further reduced to the likely achievable technology market share accessible to the technology as compared to other advanced technologies. And, finally, it was reduced to the savings potential attributable to the program. The market size was adjusted annually by the spreadsheet logic, based on the specified annual percentage growth rate.

B. Baseline Technology Improvements

Continued baseline improvement in energy productivity was accounted for in the ITP methodology. ITP's method essentially subtracted a fixed "next best" baseline technology from a fixed advanced technology to obtain unit technology savings. However, the energy savings of a new technology were determined by the number of years the technology's market introduction is accelerated by the Federal program involvement. In particular, the energy savings associated with the program were explicitly projected to occur without the EERE R&D after a period of years known as the "acceleration period." Only the slice of energy savings attributable to the program's effort to accelerate technology development was counted as GPRA savings. In this way, the methodology incorporated an assumption that the energy intensity of industrial production will steadily improve, and that specific Federal interventions in cofunding R&D only temporarily accelerate the rate of improvement in the targeted production activities. Acceleration Periods varying from about six years to 25 years were found in the GPRA05 runs.

Likewise, in the ITP off-line study, the conventional technology to which each new technology was compared was generally the best currently available technology—not a projected technology that might exist at the time of market introduction or future sales of the new technology, nor the average technology in use. While the industry-level rate of improvement in production energy intensity tends to follow fairly smooth curves of monotonic improvement, it is very difficult to predict the future energy performance of as-yet unidentified technologies to perform specific functions. In addition, the best currently available technology is often not yet widely adopted in the market, so that when the ITP technology enters the market, the current best-available technology may still represent the next-best decision alternative for many cases. Again, taking credit for only that slice of savings due to the presumed acceleration of the new technology's market introduction date was intended to minimize any overestimation of savings due to the underlying rate of technology improvement.

The commercial introduction of a technology normally occurs after a significant demonstration or operating prototype and after an adequate test and evaluation period along with allowances for the beginnings of production, dissemination of information, initial marketing and sales, or other "start-up" factors. To capture this lengthy process, users of the Technology Impact Projections Model were asked to indicate the timeline for developing and introducing the technology into the market. This includes the years for when an initial prototype, refined prototype, and commercial prototype of the technology has or will be completed; and the year when the technology will be commercially introduced. An initial prototype is the first prototype of the technology. A refined prototype represents changes to the initial prototype but not a commercially scaled-up version. A commercial prototype is a commercial-scale version of the technology. Commercial introduction is when the first unit beyond the commercial prototype is operating. Prototype and commercial introduction years were to be consistent with the technology development program plans, and two values for a commercial introduction year were requested. One reflects when the technology is projected to be introduced, if the program proceeds as expected ("With ITP" case). The other reflects when the technology would have entered the market, if the program had not been involved ("Without ITP" case). The difference in commercial introduction years for the "With ITP" and "Without ITP" cases is referred to as the acceleration period.

C. Baseline Market Acceptance

The rate of market penetration of novel technologies in industrial production markets was captured explicitly in the methodology.

Based on historical data, new technologies normally penetrate a market following a familiar "s" curve—the lower end representing the uncertainties overcome by "early adopters." The curve tails off at the far future, where some may never adopt the new technology. The steepest portion of the "s" curve is where the new technology is most rapidly penetrating the market and producing new savings. The rate at which technologies penetrate their markets varies significantly: Penetrations of heavy industrial technologies generally occur over decades, while simple process or control changes can penetrate much more rapidly. The actual penetration rate varies due to economic, environmental, competitive, productivity, regulatory, and other factors.

In a 1998 study by Arthur D. Little, Inc., data was presented on a large volume of actual penetration rates of past and present technologies. These penetration rates were analyzed, normalized, and grouped into five classes based on a number of characteristics and criteria. Users of the ITP Technology Impact Projections Model were asked to complete **Table 1** for each project by adding the project title in the top row and either a, b, c, d, or e in the right-hand column for those characteristics for which they could make a judgment. Based on the strength of these characteristic scores, the overall technology market-penetration curve selection was entered in the first row at the right under "Score." The table was copied onto the spreadsheet model run at the "Background" tab. Note that the characteristics (rows) are relatively independent, and a given technology will likely fit best in different classes for different characteristics. By examining the pattern, however, it is possible (based on best judgment and experience) to select the most likely class (rate) at which the new technology may penetrate the market. This may be a "subjective average" of the characteristics, or it is possible that one or two characteristics are expected to dominate future adoption decisions that a particular class of penetration rate is justified. There also may be "windows of opportunity," where significant replacements of existing equipment may be expected to occur in the future for other reasons. The user was asked to insert into the spreadsheet the class of penetration rate believed most likely—all things considered—and provide a narrative of the rationale for selection if not obvious from **Table 1.**

For additional context, **Table 2** shows actual technologies and the class of their historical penetration rates. Comparison of the new technology, by analogy or similarity, with these examples provided additional insight into selecting the appropriate penetration rate that might be expected for the new technology.

Table 1. Selecting the Market-Penetration Rate Class

Technology/project						**Score (a,b,c,d,e)**
Characteristic	**a**	**b**	**c**	**d**	**e**	
Time to saturation	5 yrs	10 yrs	20 yrs	40 yrs	>40 yrs	
Technology factors						
Payback discretionary	<<1 yrs	<1 yr	1-3 yrs	3-5 yrs	>5 yrs	
Payback non-discretionary	<<1 yr	<1 yr	1-2 yrs	2-3 yrs	>3 yrs	
Equipment life	<5 yrs	5-15 yrs	15-25 yrs	25-40 yrs	>40 yrs	
Equipment replacement	none	minor	unit operation	plant section	entire plant	
Impact on product quality	$$	$$	$$	$	0/-	
Impact on plant productivity	$$	$$	$$	$	0/-	
Technology experience	new to U.S. only	new to U.S. only	new to industry	new	new	
Industry factors						
Growth (% per annum)	>5%	>5%	2-5%	1-2%	<1%	
Attitude to risk	open	open	cautious	conserv-ative	averse	
External factors	forcing	forcing	driving	none	none	
Gov't regulation						
Other						

Table 2. Examples of Technologies

Class	A	B	C	D	E
Aluminum		Treatment of used cathode liners	Strip casting, VOC incinerators		
Chemicals	New series of dehydrogenation catalyst (incremental change)	CFCs -> HCFCs, incrementally improved catalysts, membrane-baed chlor-alkali	Polypropylene catalysts, solvent to water-based paints, PPE-based AN	Synthetic rubber and fibers	
Forest Products			Impulse drying, de-inking of waste newspaper	Kraft pulping, continuous paper machines	
Glass		Lubbers glass blowing, Pilkington float glass	Particulate control, regenerative melters, oxygenase in glass furnaces		
Metals Casting	New shop floor practice				
Petroleum	New series HDS catalysts	Alkylation gasoline	Thermal cracking, catalytic cracking	Residue gasification, flexicoking	
Steel	Improved EAF operating practice (e.g. modify electric/ burner heating cycle to minimize dust generation)	BOF steel making	Oxyfuel burners for steel, Level II reheat furnace controls, continuous casting, particulate control on EAF, high-top pressure blast furnace	Open-hearth technology, EAF technology	
Other		Advanced refrigerator compressors, oxygen flash copper smelting, solvent extraction with liquid ion exchange	Fluegas desulfurization (coal-fired utilities), low Nox industrial burners, industrial gas turbines, ore beneficiation		Dry-kiln cement, industrial ceramic recuperators Industrial heat pumps

Key Factors in Shaping Market Adoption of EERE Technologies

A. Price

ITP methodology places little emphasis on cost-based estimation of market penetration, because useful cost information on industrial technologies in the R&D stage of development is, in nearly all cases, impossible to obtain. Instead, relative costs in the form of the expected payback period were one of numerous market-driving factors considered in selecting the market-penetration schedule best matching each innovative technology (see previous section). These market-penetration schedules are typical of historical industrial-sector technology innovations, whose characteristic payback period, scale, equipment lifetime, impact on product quality, relevant experience level, market growth rate, attitude to risk, and other factors were matched to each innovative technology to select the best market-penetration schedule.

B. Nonprice Factors

1. Key Consumer Preferences/Values.

Several consumer preference/value issues were incorporated in the ITP market-penetration curve selection technique. These include factors such as technology scale, equipment lifetime, impact on product quality, etc. listed above.

2. Manufacturing Factors.

The benefits-estimation approach requested the analyst to estimate the year in which the technology is expected to be successfully developed at the successive stages of (1) completion of initial R&D, (2) initial system prototype, (3) refined prototype, (4) commercial prototype, and finally (5) commercial introduction, given the push provided by the ITP program support. These estimates were documented as part of each spreadsheet model run.

3. Policy Factors.

In the majority of cases, no policy factors were considered significant to the market introduction and acceptance of ITP technologies. However, for cases where a regulation or other policy will drive the market to accept a new technology solution, the market-penetration curve selection procedure was set up to accept this information and allow it to play a role in the analysis. Any such influence was discussed in documentation provided in the spreadsheet model run.

Methodology and Calculations

A. Inputs to Base Case

ITP did not provide inputs that changed the base case assumptions for the industrial markets.

B. Technical Characteristics

ITP did not provide specific changes to the NEMS-GPRA05 industrial-sector characteristics.

ITP's estimates of the energy savings of its advanced technologies were based on information provided to the analysts through the proposal review and contracting process, which includes industry participation and review, followed by program review of these estimates. ITP analysis by sector has focused on assessing where energy is actually consumed and understanding current and best practices for each proposed technology. The participation of industry experts in this process has been critical to helping refine the estimates.

C. Technical Potential

ITP's approach was to analyze the market potential and project the market performance of each of 188 advanced technologies. Market constraints (discussed above) were used in reducing the size of the market considered to the number of units both technically and economically appropriate. The benefits were further reduced to the portion fairly accredited to the ITP program.

A market-penetration curve was chosen for each technology, based on its unique characteristics in the target market. The year of commercial introduction expected, based on the program support, was estimated after documenting the prospective achievement of several logically progressive development stages. The expected year of commercial introduction without the ITP program also was estimated. Only the slice of projected savings due to the acceleration of the technologies' development by the program was counted as output savings.

While the market penetration algorithm is important, proper treatment of other market size and timing issues is equally important to the credibility of the benefit projection methodology. The extent to which the "technical potential maximum" savings were in effect discounted by the ITP approach is illustrated **Table 3**, which addresses eight technologies typical of the R&D portfolio.

Table 3. Typical Market-Penetration Discounts

Technology	2020 Actual GPRA05 Savings (TBtu)	2020 % Market Share With ITP	2020 % Market Share Without ITP	2020 Implicit Technical Potential Maximum Savings (TBtu)
Next Generation Glass Melter	18.6 TBtu	60%	3%	18.6/(0.6-0.03)= 32.6 TBtu
Advanced Lost Foam Casting	8.1 TBtu	80%	0%	8.1/(0.8)=10.1 TBtu
Inert Metal Anode	19.2 TBtu	72%	4%	19.2/(0.72-0.04)=28.2 TBtu
Development of Non-Aqueous Enzymes	42.8 TBtu	15%	2%	42.8/(0.15-0.02)=329.2 TBtu
Improved Recovery Boiler Performance	22.6 TBtu	87%	40%	22.6/(0.87-0.40)=48.1 TBtu
Alternative Anode Reaction For Electrowinning	9.2 TBtu	18%	0%	9.2/0.18=51.1 TBtu
Super Boiler	185.5 TBtu	63%	3%	185.5/(0.63-0.03)=309.2 TBtu
Mesabi Nugget Research Project	60.9 TBtu	73%	22%	60.9/(0.73-0.22)=119.4 TBtu

D. Summary of Off-line ITP Impact Calculations

1. R&D Planning Units

GPRA05 energy savings in the ITP off-line study were projected for individual projects within planning units and summed to total results for planning units and for ITP as a whole. Active projects were selected by the ITP program managers for GPRA05; thus, the FY 2004 program portfolio was used as a surrogate for the (as-yet unknown) FY 2005 portfolio. The number of study projects in each planning unit was controlled to represent an aggregate nominal funding level not greater than 100% of the FY 2004 budget.

This prospective assessment was carried out with the aid of an experience-based market-penetration model designed to estimate the national energy, economic, and environmental impacts of innovative industrial technologies. ITP's off-line calculations for GPRA05 did not utilize the model's capabilities to project environmental and cost impacts, so the results will focus only on energy savings. EERE guidance for GPRA05 was to project the energy impacts of the FY 2005 portfolio, which subsequently were used by others to specify scenario projections by the NEMS-GPRA05. The resulting NEMS-GPRA05 runs (reported elsewhere) produce environmental and cost results using integrated demand and supply assumptions consistent across the demand sectors.

The Technology Impact Projections Model was used to estimate the potential energy savings resulting from research, development, and demonstration projects funded by the Industrial Technologies Program (ITP). Benefit estimates are critical for evaluating projects and presenting the merits of both individual projects and the overall RD&D portfolio.

Proposers responding to a Solicitation or Request for Proposals were asked to use the Technology Impact Projections Model to estimate program impacts. Where not provided in proposals, principal investigators were asked to provide inputs for their active projects. Use of the model across all projects allows ITP to estimate the impacts of its projects in a consistent manner.

Users were asked to provide their best estimate for each piece of information required for the spreadsheet model. A description of the advanced technology was required to provide an overview of the project/technology. This includes the project name, ITPIS number (once project is funded), estimates preparer, program manager, planning unit, lab and industry contacts, and data sources. A narrative summary of the technology on which benefit estimates are based was required. This described what constitutes a typical process unit for the technology, in terms of annual output (production capacity times duty factor). For simplicity, the analysis assumed that all units in the industry have the same capacity. A realistic, average, or typical unit capacity was chosen, particularly for situations where the unit size may vary in different installations. By convention and to enable comparisons, units for the new technology and the current state-of-the-art were equal in output capacity; even if, in reality, the new technology might have a different capacity for various reasons.

The new technology also might not be a physical item of hardware. Rather, it could be a process change, a computer model or control system, operational change, or other nonphysical technique. In such cases, a unit was defined as the typical or average process or plant that would utilize the new technique. The annual energy inputs, based on the expected energy consumption of the process or plant with the new technique, were then compared with annual energy consumption required by existing techniques.

Key information was provided on the performance of single installed units or applications of the advanced technology. For comparison, information was required on the performance of the best-available technology for the application, not the average of all in-place technology units.

Users were required to provide energy use per year for the new and conventional units, by fuel:

- **Electricity** - Includes direct electricity.
- **Natural Gas** - Includes pipeline fuel natural gas and compressed natural gas.
- **Petroleum** - Includes residual fuel, distillate fuel, and liquid petroleum gas.
- **Coal** - Includes metallurgical coal, steam coal, and net coal coke imports.
- **Feedstock** - Includes fossil fuels consumed in nonenergy uses such as process feedstocks.
- **Biomass** - Includes the use of biomass (for energy or as feedstock).
- **Wastes** - Includes the use of fuels that are generated as wastes or process by-products. Examples of such fuels are refinery fuel gas, blast furnace gas, hog and bark fuel, and sewage sludge.
- **Other** - Includes any fuels that may not be included in those listed above.
- **Total Primary Energy** - Is calculated from individual energy inputs. The primary equivalent of direct electricity consumption includes losses in electricity generation and distribution. For GPRA05, fuel and electricity savings were used as inputs to specify NEMS-GPRA05 runs that themselves applied heat rates, etc. varying over time to produce primary energy savings.

Energy use was entered in physical units (e.g., billion cubic feet of natural gas) or primary units (trillion Btu). The exception was electricity use, which has to be entered as site energy consumption (either in billion kWh or trillion Btu).

To determine the potential impact of the new technology as it becomes adopted, it was necessary to estimate the total market for the technology, reduce that to the likely actual market, and estimate when—and the rate at which—the new technology will penetrate the market.

Users were required to estimate the number of installed units in the U.S. market in a specified year. That market was defined as narrowly as possible: The smallest group of applications that covers all potential applications for which the user may have some data. Users could apply their own data on energy use of the state-of-the-art technology. Other potential data sources include ITP's Energy and Environmental Profile for the relevant industry, EIA's MECS data, or industry sources.

The annual market growth rate was specified by the model user, based on an EIA or industry growth projection for the relevant industry. A citation for the growth rate was called for in the comments section.

Market share was specified as a function of the potential accessible market share and the likely market share. The Potential Accessible Market Share was defined as the market that the new technology could reasonably access given technical, cost, and other limitations of the technology. For example, certain technologies may be applicable only to a certain scale of plant, certain temperature-range processes, certain types of existing equipment or subsystems, or only certain segments of the industry. A further delimiting fraction was called the Likely Market Share. In some instances, in addition to technical and cost factors, the technology may compete with other new technology approaches (or with other companies) for the market. The user was asked to use current market-share information or base their estimated market share on the number of competitors in the market, assuming they are using different technologies not resulting from this project. This is different than the possibility of "copycats," which should not be considered as competing. That is, if others adopt essentially the same (or slightly modified) technology due to this new technology, that adoption was triggered by the project being described and that project should be "credited" with causing that trend. This is potentially the case for techniques where the intellectual property cannot be, or is not, protected and becomes general knowledge throughout the industry.

In some instances, a program may be developing a technology in conjunction with another ITP, EERE, or DOE program. The analysts were asked in these cases to provide an estimate of the percentage of savings that is attributed to the program. The attribution percentage should be similar to the percentage of Federal funds provided to the project by the program. A default value of 100% was entered in the model.

To understand how rapidly the potential impact of the technology may be felt, the market penetration of the technology must be projected. This is based on two estimates: the technology development and commercialization timeline, and the market penetration curve.

The technology development and commercialization timeline was first determined. The commercial introduction of a technology normally occurs after a significant demonstration or operating prototype and after an adequate test-and-evaluation period, along with allowances for the beginnings of production, dissemination of information, initial marketing and sales, or other "start-up" factors. To capture this lengthy process, the analyst indicated the timeline for developing and introducing the technology into the market. This includes the years for when an initial prototype, refined prototype, and commercial prototype of the technology has or will be completed, as well as the year when the technology will be commercially introduced. An initial prototype is the first prototype of the technology. A refined prototype represents changes to the initial prototype but not a commercially scaled-up version. A commercial prototype is a commercial-scale version of the technology. Commercial introduction is when the first unit beyond the commercial prototype is operating. Prototype and commercial-introduction years were to be consistent with the technology-development program plans. Two values for a commercial introduction year were requested. One reflected when the technology is projected to be introduced, if the program proceeds as expected ("With ITP" case). The other reflected when the technology would have entered the market if the program had not been involved ("Without ITP" case). If the technology would not have been commercially introduced without the program, then a year of 2050 for the "Without ITP" case was entered. The difference in commercial introduction years for the "With ITP" and "Without ITP" cases is referred to as the acceleration period.

New technologies normally penetrate a market following a familiar "s" curve, the lower end representing the above uncertainties overcome by "early adopters." The curve tails off where some may never adopt the new technology. The major portion of the "s" curve, where the new technology is penetrating the market and benefits are being reaped, is most important. The rate at which technologies penetrate their markets varies significantly: Penetrations of heavy industrial technologies generally take place over decades, while simple process or control changes can penetrate much more rapidly. The actual penetration rate varies due to economic, environmental, competitive, productivity, regulatory, and other factors.

Technology impact projections model runs for individual R&D projects receiving R&D support were aggregated to obtain energy savings associated with each R&D planning unit. In aggregating the savings, market targets were examined explicitly to avoid double-counting the same potential savings in the infrequent instances when the same energy efficiency market is clearly addressed by multiple projects. Where possible market overlaps were found, the markets were either assigned to only one technology or divided among the competing technologies under development. This process increases confidence that any systemic double-counting within planning units has been minimized. Nevertheless, some double-counting across planning units within ITP or with other EERE programs is assumed to remain.

The approximate portion of the FY 2004 budget represented by the analysis for each planning unit was noted, but the results were not scaled to 100% of the FY04 budget. Typically, the projects analyzed represented 75% to 95% of the FY04 budget for the various planning units. Projected benefits for these planning units do not include the effects of R&D projects completed prior to the current year.

The justification for assuming that all of the projects analyzed will succeed is twofold. First, projects that fail will likely be replaced with new projects using different technical approaches to achieve similar goals. Using this theory, the basic goals will be met by the program in the long run and continuously funded. Second, the projects analyzed do not comprise 100% of the FY04 budget, which in itself discounts the aggregated results, equivalent to incorporating some risk of failure into the overall process. In addition, the knowledge benefits of ITP's R&D portfolio are not assessed here; this scientific and technical knowledge can help to underpin additional production technology innovations in the future, and spin-off applications in both the near and longer terms.

2. Technical Assistance Planning Units

The Industrial Analysis Center program and the Best Practices program were assessed, based on retrospective analysis of performance data accumulated over a period of years. ITP's off-line Quality Metrics study for these planning units is based on the premise that continuation of the programs will result in beneficial impacts proportional to documented experience at historical budget levels. These analyses did not count as savings any continuing contributions from prior program expenditures, but only assumed that future expenditures will produce results proportionate to those reported for past expenditures.

The approaches for calculating the impacts of the IAC and best-practices planning units were similar. In each case, those program activities associated historically with documented energy savings were projected into the future based on assumed continuation at the FY05 budget level. The numbers of assessments, Web site visitors, trained individuals, etc. performed in each future year were used to logically arrive at the future energy savings attributable to the activity, given continued performance at historical levels of effectiveness. Each quantity and assumption was explicitly shown in a tabular format intended to show the contribution of each step of the calculation to the final result and to make the entire analytical process repeatable.

The IAC program benefits were supported by 21 years of actual assessment and implementation data. Among other assumptions, the effects of assessments were projected to last for seven years. The effects of student training were projected to persist for 11 years. The effects of the Web site information activity were projected to last for seven years.

Best Practices program benefits were based on preliminary findings of an Oak Ridge National Laboratory study of program effects in 2001 and 2002. The basic methodology used in each of five best-practices activity areas was very similar. First, the activity reach was estimated by calculating the number of individuals touched by best-practices information. This number was then scaled back to calculate the number of plants taking action, due to this information dissemination. The scale-back factors included accounting for duplicate “touches” within the same company, the percentage of companies actually taking action, and a reduction factor to discount program credit due to it being but one of multiple sources of influence. To obtain the total program energy savings, reported rates of energy savings were applied to the number of plants estimated to be affected by best-practices activities in each future year.

Appendix I – GPRA05 Solar Energy Technologies Program Documentation

GPRA Baseline Assumptions

Several changes from the *Annual Energy Outlook 2003 (AEO2003)* Reference Case were incorporated into the GPRA05 Baseline, in consultation with the Solar Energy Technologies Program. These changes include:

(1) Increasing the average commercial-building system size from 10kW to 100kW. A sample of data from 14 PV systems, installed between July 1999 and March 2003 by PowerLight Corporation, reveals that the average commercial system installed by PowerLight during this period was 381kW (**Table 1**).

Table 1. Commercial System Size and Surface-Area Requirements

PowerLight System Installation Location	Date Completed	Sytem Peak Capacity (kW)	PV Surface Area (sq. ft.)	W/sq.ft.
Santa Rita Jail - Alameda County, California	Apr-02	1,180	130,680	9.0
Cypress Semiconductor - San Jose, California	Jul-02	335	26,100	12.8
Fala Direct Marketing - Farmingdale, New York	Nov-02	1,010	102,700	9.8
Fetzer Vineyards, Hopland, California	Jul-99	41	3,750	10.9
Franchise Tax Board, Sacramento, California	Aug-02	470	50,000	9.4
Greenpoint Manufacturing - Brooklyn, New York	Mar-03	115	11,500	10.0
Mauna Lani Resort – Kohala Coast, Hawaii	Jan-02	528	43,330	12.2
Naval Base Coronado, California	Sep-02	924	81,470	11.3
Neutrogena Corporation - Los Angeles, California	Aug-01	229	30,154	7.6
Parker Ranch – Kameula, Hawaii	Jan-01	209	20,000	10.5
PSGA/Ortho-McNeil Facility - Pennsylvania	Apr-02	75	17,500	4.3
US Coast Guard – Boston, Massachusetts	Sep-99	37	3,800	9.7
US Postal Service - Marina del Rey, California	Nov-01	127	15,000	8.5
Yosemite National Park - Yosemite, California	Oct-01	47	4,500	10.4
Total		**5,327**	**540,484**	
Average		**381**	**38,606**	**10**

Source: PowerLight Case Study data sheets, downloaded from www.powerlight.com, 5/21/03.
Note: Some of the locations shown in this table have multiple installations. In these cases, the total installed capacity is shown above and the most recent installation date is shown in the date completed col.

The average space required for these systems was 10 sq. ft/W., based on a U.S. average commercial building size in 2000 of 14,500 square feet (AEO2003), and assuming a ratio of usable roof space to floor space of 0.7. This ratio of usable roof space to floor space was based on the "architecturally suitable area" in an International Energy Agency (IEA) report, Table 2, examining the potential for integrated photovoltaics in buildings (IEA 2001). Using this approximation, the average commercial building could easily accommodate a 100 kW PV system, i.e., a 0.7*14,500 sq. ft. = 10,100 sq. ft. PV array. Thus, setting the average system size at 100kW is a conservative assumption based on industry trends, as well as the available roof space on a large share (50+%) of the commercial building stock. This is a very conservative assumption based on the expectations that the efficiency of PV cells will increase; the space requirements for a PV system will decrease; and, as system costs decline, facades and other spaces (such as parking lots) also could be utilized for PV systems.

(2) Increasing the maximum share of commercial buildings with solar access from 30% to 55%. Similar to the preceding ratio of usable roof space to floor space, the share of roof space suitable for PV installations was based on the recently published IEA report on integrated photovoltaics in buildings (IEA 2001). This report indicates that a reasonable estimate for the share of roof space suitable for PV installations is 55%. This estimate includes shading and other factors that would limit the use of roof space for PV systems (IEA 2001).

(3) Increasing the average residential building system size from 2kW to 4kW. A couple of years ago, a typical residential rooftop PV system was a 2kW system—this is most likely the source for EIA's 2kW system size in the *AEO2003* reference case. However, residential rooftop systems being installed in Japan, Europe, and the United States have been growing larger. For example, the average Japanese rooftop system size in 2002 was 3.7 kW (Ikki 2003). The average home in the United States has 1,700 square feet of floor space (this is expected to increase). Using data from EIA's residential energy-consumption survey (EIA 1999, Table HC1-2a) one can estimate a floor- to roof-space ratio of 0.7 (based on distribution of one-story, two-story, and three-story single-family homes). This is a conservative estimate—most homes have pitched roofs, which would increase the total available roof space (yet may make a significant portion of the roof oriented away from the sun). If a typical system requires 10 sq. ft./W (as above), then a 4kW system would require roughly 400 square feet of roof space, which is well below the average available space allowing for multiple floors and pitched roofs. Thus, roof space is not a constraint for installing residential rooftop PV systems in the 4kW range. Because the efficiency of PV cells is likely to improve, a trend toward larger systems on rooftops is likely to continue. Thus, based on available roof space and what is happening in the marketplace, setting the average system size at 4kW is a conservative assumption.

(4) Increasing the maximum share of residential buildings with solar access from 30% to 60%. A maximum share of 60% for residential buildings with solar access was estimated by Walter Short (2003). This estimate includes building orientation, roof construction, roof equipment, and layout. This value was calculated from a combination of single-family homes (70%) and multifamily homes (30%), using a 75%–25% split between single-family and multifamily homes (EIA 2003, Table A4). Thus, the average maximum share is 0.7*0.75 + 0.3*0.25 = 0.6

(5) Including a declining PV buy-down program in California. This estimation assumed that the California renewable energy-credit program (which provided a PV credit of $4,000/kW in 2003) will continue to be available, but will decline by $400/kW per year. This credit was included for the entire Pacific region. Because a number of other local credits were not included in the GPRA baseline, applying the California state-level credit to the whole Pacific region is likely to be a reasonable approximation.

(6) Modifying the adoption rate of distributed generation technologies. The modification to the adoption rate was based on information provided by the DEER program (**Figure 1**). This applies to PV as well as gas-fired CHP technologies.

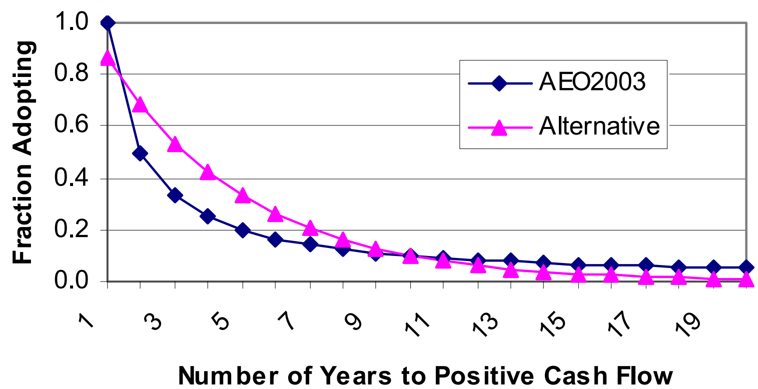

Figure 1. Commercial-Sector DG Adoption Rates

These changes lead to increased adoption of PV systems in the baseline. However, the *AEO2003* assumptions about PV installations through the Million Solar Roofs program were removed, so that there would not be double-counting when these were introduced in the GPRA Program Case.

One additional NEMS-GPRA05 model modification was made in the residential module. Solar water heaters were added as a technology option for new homes, and the algorithm governing water-heater replacements was modified so that solar water heaters could compete in a larger market.

GPRA05 Solar Program Scenario Assumptions

Two key sets of assumptions were modified to generate the GPRA05 Solar Energy Technologies Program scenario.

(1) Green power additions. Green power additions by region, from Princeton Energy Resources International (PERI), were added back into the Solar Program scenario (**Table 2**). These projections take into account the Baseline assumptions of noneconomic capacity additions. This capacity is added in NEMS-GPRA05 as "planned" additions. The capacity factors for the regions east of the Mississippi were assumed to be half of those for the western regions (EIA does not include CSP in these regions because it assumes that CSP is not cost-effective due to lower solar insolation levels).

Table 2. Incremental Green Power PV Capacity Additions (MW)

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2005-2025
ECAR	7	81	198	159	50	495
ERCT	2	27	64	49	16	158
MAAC	6	75	179	142	44	447
MAIN	1	8	22	16	5	52
MAPP	0	5	13	12	4	34
NY	0	5	11	6	2	24
NE	0	7	15	10	3	35
FL	12	135	326	265	83	821
STV	36	406	978	795	248	2,464
SPP	3	30	72	57	18	180
NWPP	1	6	16	15	6	43
RA	1	11	28	22	8	70
CNV	0	0	1	6	4	11
Total	**70**	**796**	**1,923**	**1,554**	**491**	**4,834**

(2) Technology Characteristics. More aggressive technology targets were used. These technology characteristics were provided by the Solar Program for the range of solar technologies: concentrating solar power (CSP), central PV systems, distributed PV systems, and solar water-heating systems. Note that the CSP technology assumptions were not included in the final benefits analysis because it was not included in the FY05 Budget Request.

A multilab, multitechnology team was assembled to define a consistent set of long-term targets to 2050. This team produced technology cost projections for use in NEMS-GPRA05 that are consistent with the Solar Program's Multi-Year Technical Plan (which was being written concurrently to the GPRA05 analysis) and will soon be available on the EERE Web site. The Multi-Year Technical Plan includes cost targets though the 2020-2025 period (varying by technology). Thus, the targets shown in **Table 3** and **Table 4** are consistent with the Multi-Year Technical Plan through the 2020-2025 time frame. Beyond 2025, the targets are increasingly uncertain and are likely to be revised as the Solar Program continues to analyze the long-term prospects for PV technology cost reductions. Although the costs shown below are for specific years, the costs decline annually between years.

Table 3. PV Systems

	Central Generation		Residential Buildings		Commercial Buildings	
Year	Installed Price (2001$/kW)	O$M (2001$/kW)	Installed Price (2000$/kW)	O$M (2000$/kW)	Installed Price (2000$/kW)	O$M (2000$/kW)
2003	5,300	60	9,450	160	6,250	160
2007	3,600	40	6,250	40	4,500	40
2020	2,000	10	2,800	10	2,800	10
2025	1,700	9	2,380	9	2,380	9
2050	1,050	5	1,470	5	1,470	5

Two solar water heaters, which have different efficiencies or electric backup requirements, are represented

Table 4. Residential Solar Water Heat

		Best (High efficiency)			Minimum (Typical efficiency)		
First Year	Last Year	Efficiency	Total Installed Cost($01)	Retail Equipment Cost($01)	Efficiency	Total Installed Cost($01)	Retail Equipment Cost($01)
1997	2004	2.5	2800	1250	2.0	2300	1200
2005	2009	2.6	2200	1000	2.1	2000	1000
2010	2019	2.7	1400	700	2.2	1000	500
2020	2025	3.0	1200	600	2.5	800	400
2026	2030	3.5	1020	510	2.7	680	340
2031	2035	4.0	867	434	2.8	578	289
2036	2040	4.5	780	390	2.9	520	260
2041	2050	5.0	741	371	3.0	494	247

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Appendix J – GPRA05 Vehicle Technologies Program Documentation

Light-Vehicle Characterization

Light-vehicle (LV) attributes were based on the FreedomCAR and Vehicle Technologies (FCVT) program goals, discussions with FCVT program managers, and technical analysis by contractors (Ref. 1). They were also based on a review of past GPRA characterizations (e.g., attributes included in the 2003 GPRA transportation methodology report that can be found on the EERE Web site (Ref. 2). Because the two models (NEMS-GPRA05 and MARKAL-GPRA05) that generate GPRA results require different levels of detail, the technical characterizations were provided in two parts: one for input to NEMS-GPRA05 and one for input to MARKAL-GPRA05. The discussion of the LV characterization is, thus, divided into two parts below.

Input to NEMS-GPRA05

Table 1 contains vehicle attributes for advanced diesels, diesel hybrids, gasoline hybrids, and hydrogen (H2) internal-combustion engines (ICEs). These advanced technologies may be used in cars and light trucks (LTs). Attributes are provided for the four technologies in six car size classes and six LT classes. (H2 ICEs are characterized for fewer classes.) The attributes are for new vehicles in the year listed. The attributes include the following:

- Vehicle Price
- Range
- Maintenance Cost
- Acceleration
- Top Speed
- Luggage Space
- Fuel Economy

The attributes for the four technologies are provided as ratios to the vehicle attributes of conventional vehicles. **Table 1** presents the baseline conventional vehicle price and fuel economy attributes assumed for this analysis.

The attributes of the four advanced technologies vary over time. The four technologies are at different stages of technology development and, thus, are expected to penetrate the LV market at different times. Attributes were provided by the FCVT program for each technology/size class at the time of market introduction, at market maturity (generally identified by achievement of fuel economy goals), at price maturity, and for the year 2025. These attributes were implemented in NEMS-GPRA05 as step-functions over time.

Price and fuel economy are the two most important attributes characterized. The incremental price over a conventional vehicle for any vehicle of a specific size class and technology at market maturity is estimated using a three-year payback period. (The incremental price equals the present value of the energy cost reduction achieved by advanced technology vehicles over three years.) Incremental prices are assumed to be 50% higher at market introduction than at market maturity and 20% lower at price maturity.

Input to MARKAL-GPRA05

The MARKAL-GPRA05 model provides the benefits estimates for the GPRA analysis out to 2050. The model does not require LV characterization at the level of detail that NEMS-GPRA05 does. There is no disaggregation of cars and LTs into size classes and only cost and fuel economy ratios are required. **Table 2** presents the LV characterization input to MARKAL-GPRA05. H2 ICEs are transitional to the more efficient use of H2 in fuel cell vehicles and, thus, are not expected to continue in the market post-2025. Therefore, they are not in **Table 2**.

References

1. "Strategic Plan," U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, DOE/GO-102002-1649 (October 2002).

2. "Program Analysis Methodology: Office of Transportation Technologies, Quality Metrics 2003 Final Report,"prepared by OTT Analytic Team, for Office of Transportation Technologies, U.S. Department of Energy (March 2002).

Table 1: Attributes of Advanced Technology Vehicles Relative to Conventional Vehicles (CV)

	2-SEATER				MINI-COMPACT				SUB-COMPACT				COMPACT			
CV Price (000s) /MPG	43.3/19.1				54.3/19.5				19.4/23.4				19.8/23.1			
	Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity	
Advanced Diesel	**2014**	**2019**	**2024**	**2025**	**2012**	**2017**	**2022**	**2025**	**2010**	**2015**	**2020**	**2025**	**2008**	**2013**	**2018**	**2025**
Vehicle Price	1.036	1.024	1.019	1.018	1.028	1.019	1.015	1.013	1.066	1.044	1.035	1.030	1.066	1.044	1.035	1.030
Range	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Maintenance Cost	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Acceleration	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Diesel Hybrid	**2016**	**2021**	**2025**	**N/A**	**2014**	**2019**	**2024**	**2025**	**2012**	**2017**	**2022**	**2025**	**2010**	**2015**	**2020**	**2025**
Vehicle Price	1.072	1.036	1.030		1.045	1.030	1.024	1.023	1.132	1.070	1.056	1.050	1.104	1.069	1.055	1.050
Range	1.25	1.25	1.25		1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05		1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	1.00	1.00	1.00		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	1.00	1.00	1.00		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.95	0.95	0.95		0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Fuel Economy	1.60	2.00	2.00		1.70	2.10	2.10	2.10	1.70	2.10	2.10	2.10	1.70	2.10	2.10	2.10
Gasoline Hybrid	**2013**	**2018**	**2023**	**2025**	**2011**	**2016**	**2021**	**2025**	**2009**	**2014**	**2019**	**2025**	**2007**	**2017**	**2017**	**2025**
Vehicle Price	1.065	1.035	1.025	1.022	1.040	1.027	1.022	1.018	1.185	1.063	1.050	1.045	1.094	1.062	1.050	1.040
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Top Speed	1.00	1.00	1.00	1.00	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Fuel Economy	1.60	1.90	1.90	1.90	1.60	1.90	1.90	1.90	1.60	1.90	1.90	1.90	1.60	1.90	1.90	1.90
Hydrogen ICE	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**2014**	**2020**	**2020**	**N/A**
Vehicle Price													1.250	1.150	1.150	
Range													0.55	0.75	0.75	
Maintenance Cost													1.00	1.00	1.00	
Acceleration													0.85	0.95	0.95	
Top Speed													1.00	1.00	1.00	
Luggage Space													0.55	0.75	0.75	
Fuel Economy													1.10	1.20	1.20	

Table 1 (continued)

	MEDIUM CAR				LARGE CAR			
CV Price (000s) /MPG	25.9/20.4				30.3/18.9			
	Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity	
Advanced Diesel	**2007**	**2012**	**2017**	**2025**	**2005**	**2010**	**2015**	**2025**
Vehicle Price	1.049	1.033	1.026	1.022	1.045	1.030	1.024	1.018
Range	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Maintenance Cost	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Acceleration	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Diesel Hybrid	**2012**	**2017**	**2022**	**2025**	**2010**	**2015**	**2020**	**2025**
Vehicle Price	1.073	1.049	1.039	1.037	1.068	1.045	1.036	1.030
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Fuel Economy	1.50	1.75	1.75	1.75	1.50	1.75	1.75	1.75
Gasoline Hybrid	**2004**	**2009**	**2014**	**2025**	**2004**	**2009**	**2014**	**2025**
Vehicle Price	1.057	1.038	1.030	1.025	1.053	1.035	1.028	1.020
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.85	0.95	0.95	0.95	0.85	0.95	0.95	0.95
Fuel Economy	1.35	1.50	1.50	1.50	1.35	1.50	1.50	1.50
Hydrogen ICE	**2012**	**2020**	**2020**	**N/A**	**2010**	**2020**	**2020**	**N/A**
Vehicle Price	1.200	1.150	1.150		1.200	1.100	1.100	
Range	0.48	0.75	0.75		0.50	0.75	0.75	
Maintenance Cost	1.05	0.95	0.95		1.05	0.95	0.95	
Acceleration	0.95	1.00	1.00		1.00	1.00	1.00	
Top Speed	1.00	1.00	1.00		1.00	1.00	1.00	
Luggage Space	0.50	0.75	0.75		0.55	0.80	0.80	
Fuel Economy	1.10	1.15	1.15		1.10	1.15	1.15	

Table 1 (continued)

	MINIVAN				LARGE VAN			
CV Price (000s) /MPG	26.7/18.2				23.0/14.6			
	Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity	
Advanced Diesel	**2006**	**2011**	**2016**	**2025**	**2004**	**2009**	**2014**	**2025**
Vehicle Price	1.053	1.035	1.028	1.024	1.054	1.036	1.029	1.025
Range	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Maintenance Cost	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Acceleration	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy	1.40	1.40	1.40	1.40	1.25	1.25	1.25	1.25
Diesel Hybrid	**2011**	**2016**	**2021**	**2025**	**2010**	**2015**	**2020**	**2025**
Vehicle Price	1.080	1.053	1.043	1.025	1.101	1.067	1.054	1.040
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.09	1.05	1.05	1.05	1.09	1.05	1.05	1.05
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Fuel Economy	1.50	1.75	1.75	1.75	1.40	1.60	1.60	1.60
Gasoline Hybrid	**2004**	**2009**	**2014**	**2025**	**2008**	**2013**	**2018**	**2025**
Vehicle Price	1.062	1.041	1.033	1.028	1.054	1.036	1.029	1.025
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	0.75	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	0.90	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy	1.35	1.50	1.50	1.50	1.20	1.25	1.25	1.25
Hydrogen ICE	**2010**	**2020**	**2020**		**2008**	**2018**	**2020**	
Vehicle Price	1.200	1.100	1.100		1.250	1.150	1.080	
Range	0.55	0.75	0.75		0.50	0.70	0.75	
Maintenance Cost	1.00	0.95	0.95		1.05	1.00	0.95	
Acceleration	1.00	1.00	1.00		1.00	1.00	1.00	
Top Speed	1.00	1.00	1.00		1.00	1.00	1.00	
Luggage Space	0.65	0.85	0.85		0.80	0.90	0.92	
Fuel Economy	1.10	1.15	1.15		1.10	1.15	1.15	

Table 1 (continued)

	SMALL SUV				LARGE SUV				SMALL TRUCK				CARGO (Incl. 2b) TRUCK			
CV Price (000s) /MPG	27.7/17.2				35.2/14.1				18.5/18				25.3/15.1			
	Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity		Intro	Market Maturity	Price Maturity	
Advanced Diesel	**2004**	**2009**	**2014**	**2025**	**2007**	**2012**	**2017**	**2025**	**2003**	**2008**	**2013**	**2025**	**2003**	**2008**	**2013**	**2025**
Vehicle Price	1.063	1.042	1.034	1.026	1.053	1.035	1.028	1.023	1.084	1.056	1.045	1.038	1.066	1.044	1.035	1.031
Range	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Maintenance Cost	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Acceleration	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Economy	1.40	1.50	1.50	1.50	1.30	1.40	1.40	1.40	1.40	1.45	1.45	1.45	1.40	1.40	1.40	1.40
Diesel Hybrid	**2011**	**2016**	**2021**	**2025**	**2015**	**2020**	**2025**	**N/A**	**2012**	**2017**	**2022**	**2025**	**2016**	**2021**	**2025**	**N/A**
Vehicle Price	1.084	1.056	1.045	1.036	1.078	1.052	1.035		1.121	1.080	1.064	1.059	1.102	1.068	1.054	
Range	1.20	1.20	1.20	1.20	1.20	1.20	1.20		0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05		1.05	1.05	1.05	1.05	1.05	1.05	1.05	
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90		0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00		0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00		0.80	0.90	0.90	0.90	0.80	0.90	0.90	
Fuel Economy	1.60	1.80	1.80	1.80	1.50	1.75	1.75		1.50	1.80	1.80	1.80	1.50	1.75	1.75	
Gasoline Hybrid	**2004**	**2009**	**2014**	**2025**	**2005**	**2010**	**2015**	**2025**	**2006**	**2011**	**2016**	**2025**	**2007**	**2012**	**2017**	**2025**
Vehicle Price	1.063	1.042	1.034	1.026	1.053	1.035	1.028	1.023	1.091	1.060	1.048	1.040	1.061	1.041	1.033	1.030
Range	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Maintenance Cost	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Acceleration	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Top Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Luggage Space	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.80	0.95	0.95	0.95	0.80	0.95	0.95	0.95
Fuel Economy	1.35	1.50	1.50	1.50	1.25	1.40	1.40	1.40	1.35	1.50	1.50	1.50	1.25	1.35	1.35	1.35
Hydrogen ICE	**N/A**	**N/A**	**N/A**	**N/A**	**2010**	**2020**	**2020**	**N/A**	**2009**	**2018**	**2020**	**N/A**	**2008**	**2018**	**2020**	**N/A**
Vehicle Price					1.200	1.100	1.100		1.300	1.150	1.100		1.200	1.100	1.060	
Range					0.55	0.75	0.75		0.50	0.70	0.75		0.50	0.70	0.75	
Maintenance Cost					1.00	0.95	0.95		1.00	1.00	0.95		1.05	1.00	0.95	
Acceleration					1.00	1.00	1.00		1.00	1.00	1.00		1.00	1.00	1.00	
Top Speed					1.00	1.00	1.00		1.00	1.00	1.00		1.00	1.00	1.00	
Luggage Space					0.60	0.82	0.82		0.50	0.72	0.75		0.50	0.75	0.80	
Fuel Economy					1.12	1.15	1.15		1.10	1.15	1.15		1.10	1.15	1.15	

Table 2. Light-Vehicle Characteristics for Analysis of FCVT Program Using MARKAL-GPRA05 Model

Vehicle Type	Technology	Ratio	2010	2020	2030	2040	2050
Car	Gasoline HEV	Cost	1.09	1.05	1.03	1.02	1.01
		MPG	1.50	1.70	1.90	2.00	2.00
	Diesel	Cost	1.07	1.04	1.02	1.02	1.02
		MPG	1.40	1.50	1.50	1.60	1.60
	Diesel HEV	Cost	1.12	1.07	1.05	1.04	1.04
		MPG	1.70	1.90	2.10	2.19	2.27
LT	Gasoline HEV	Cost	1.10	1.06	1.04	1.03	1.02
		MPG	1.35	1.50	1.60	1.62	1.64
	Diesel	Cost	1.08	1.05	1.03	1.02	1.02
		MPG	1.40	1.45	1.50	1.61	1.60
	Diesel HEV	Cost	1.13	1.09	1.07	1.06	1.05
		MPG	1.50	1.75	1.80	1.81	1.82

Heavy-Vehicle Characterization

Introduction

This report describes the approach to estimating benefits and the analysis results for the heavy-vehicle technologies activities of the FreedomCAR and Vehicle Technologies Program of EERE. The scope of the effort included:

- Characterizing baseline and advanced technology vehicles for Class 3 – 6 and Class 7 and 8 trucks,
- Identification of technology goals associated with the DOE EERE programs
- Estimating the market potential of technologies that improve fuel efficiency and/or use alternative fuels,
- Determining the petroleum and greenhouse gas emissions reductions associated with the advanced technologies.

This narrative contains a description of the analysis methodology, a discussion of the models used to estimate market potential and benefits, and a presentation of the benefits estimated as a result of the adoption of the advanced technologies. These benefits estimates, along with market penetrations and other results, are then modeled as part of the EERE-wide integrated analysis to provide final benefit estimates reported in the FY05 Budget Request.

Background

This analysis of the benefits expected from achieving the program's goals for heavy-vehicle technologies was developed based on four primary reference sources:

- Technology energy efficiency and fuel use characteristics—as provided by the managers of the technology programs
- Vehicle characteristics and use information—as obtained from the 1997 Vehicle Inventory and Use Survey (VIUS). This provides information on both vehicle performance characteristics, such as fuel economy; and also vehicle use patterns such as miles traveled per year (Ref. 1).
- Truck operator investment requirements—as provided by a survey of Owner-Operators performed by the American Trucking Associations in 1995 (Ref. 2).
- Important "background" information, such as energy prices and baseline technology fuel economies, are based on Annual Energy Outlook 2003 (Reference Case) prepared by the Energy Information Administration (Ref. 3).

The methodology involves the disaggregation of heavy-vehicle types according to use patterns. This has enabled the identification of the vehicle types that accumulate the greatest vehicle miles traveled and, therefore, offer the best opportunity for economic viability of an investment in an energy-conserving technology. The market analysis of the heavy-vehicle sector embodied in this analysis is, thus, more robust than is available in NEMS and MARKAL and provides better estimates of the impacts of DOE's heavy-vehicle program.

The market segmentation also identifies travel distributions for heavy vehicles that utilize central refueling sites and those that do not. Central refueling will be more conducive to the introduction of an alternative fuel, because the initial refueling infrastructure required does not have to be as extensive as the alternative-fuel refueling infrastructure, which would be required for vehicles that do not centrally refuel and, thus, should be less costly.

Approach

The methodology involves the definition of the energy conservation or displacement and cost attributes of the advanced technologies being fostered by the program, the characterization of the markets affected, and the estimation of the benefits.

Technology Characteristics

The heavy-vehicle technologies span engine improvements to improve fuel economy, reduction in parasitic losses—mostly through improved aerodynamics and tire designs, and weight reduction. The programs supporting these technology development efforts focus on Class 7 and 8 trucks—as these truck classes are the dominant fuel users among Classes 3 through 8. Engine fuel economy improvements and weight reduction and hybrid vehicle systems are being developed for application in medium trucks (Classes 3 through 6). Because of differences in the utilization and types of driving conditions among various truck types, the fuel economy improvement opportunities are considered to vary according to truck type. (Truck types are discussed in the Heavy Truck Market Analysis that follows this section.) Technology characteristics are presented in **Table 3.** Ratios are relative to technology characteristics in 2005.

The cost of the technology to buyers at the time of commercialization is difficult (if not impossible) to estimate, because much of the work is in early stages of development. However, due to a survey conducted by the American Trucking Associations in 1997, buyer payback requirements are known (Ref. 2). The survey of 224 motor carriers revealed that paybacks of one to four years were acceptable for energy conserving technologies. Based on those findings, a technology goal for the time of technology commercialization was selected to be the cost that would equate to a two-year payback. Hence, for each of the technology characteristics shown in **Table 3**, payback analyses were performed. The results of one of these analyses are summarized in **Table 4.**

Table 3. Heavy-Truck Inputs for FY 05 GPRA

Class	Type or Technology	Description	2005	2010	2015	2020	2025	2030	2040	2050
7 - 8	**3**	Over the road: van								
	Engine	8.90 mpg	1	1.05	1.15	1.25	1.33	1.4	1.45	1.50
	Parasitic (aero and tires)	92,500 miles/year	1	1.03	1.13	1.24	1.35	1.45	1.58	1.70
	Weight reduction	59.6% of 7-8 vmt	1	1.01	1.03	1.08	1.11	1.14	1.17	1.20
	Total MPG Multiplier		1	1.092	1.338	1.674	1.993	2.314	2.68	3.06
	2	Regional: open								
	Engine	6.16 mpg	1	1.03	1.07	1.13	1.2	1.25	1.3	1.35
	Parasitic (aero and tires)	74,000 miles/year	1	1.01	1.04	1.08	1.1	1.13	1.15	1.17
	Weight reduction	22.6% of 7-8 vmt	1	1.003	1.01	1.02	1.05	1.07	1.09	1.10
	Total MPG Multiplier		1	1.043	1.124	1.245	1.386	1.511	1.63	1.737
	1	Local operation: heavy-duty								
	Engine	4.55 mpg	1	1.03	1.07	1.13	1.2	1.21	1.22	1.25
	Parasitic (aero and tires)	40,000 miles/year	1	1	1.01	1.02	1.03	1.04	1.05	1.05
	Weight reduction	17.8% of 7-8 vmt	1	1.003	1.01	1.02	1.03	1.04	1.05	1.06
	Total MPG Multiplier		1	1.033	1.092	1.176	1.273	1.309	1.345	1.391
3 - 6		Local operation: medium-duty								
	Engine	8.90 mpg	1	1.03	1.07	1.13	1.2	1.21	1.22	1.25
	Hybrid	20,000 miles/year	1	1.05	1.1	1.15	1.2	1.25	1.3	1.35
	Weight reduction		1	1.003	1.01	1.03	1.05	1.07	1.09	1.10
	Total MPG Multiplier		1	1.085	1.189	1.338	1.512	1.618	1.729	1.856

Source: Reference 4

The case illustrated is for Type 3 technology in 2010. The fuel economy improvement is 9.2%, the baseline fuel economy is 8.9 mpg, and the estimated usage is 92,500 miles/year as indicated in **Table 3.**

As shown in the table on the right in **Table 4** and in the graph, the incremental first cost that equates to the savings during a two-year period is $2,535. Subsequent year costs were estimated, based on the higher fuel-efficiency benefit goal of the program, but also considering production cost reductions as market penetration expands and development costs can be amortized against increasing sales.

The cost schedule for the **Table 3** technologies in the Type 3 vehicle application is indicated in **Table 5**.

This analysis was replicated for Type 1 and Type 2 vehicles and Medium Trucks.

Table 4. Payback Analysis Used to Develop Technology Cost Goal

Inputs (Assumptions--User defined):

Item	Year 1
MPG Multiplier	1.092
Fuel Economy-Conventional, mi/gal.	8.9
Vehicle Miles, mi./yr	92,500
Fuel Cost, $/gal.	$1.50
Discount Rate:	7.5%

Results: Purchase Cost Increase Equivalent to Fuel Savings

Payback, Years	Incremental First Cost, $	Payback Period Distribution, Years	Comments
5	$5,713	6.4%	
4	$4,729	6.5%	
3	$3,672	61.7%	
2	$2,535	15.5%	
1	$1,313	16.4%	

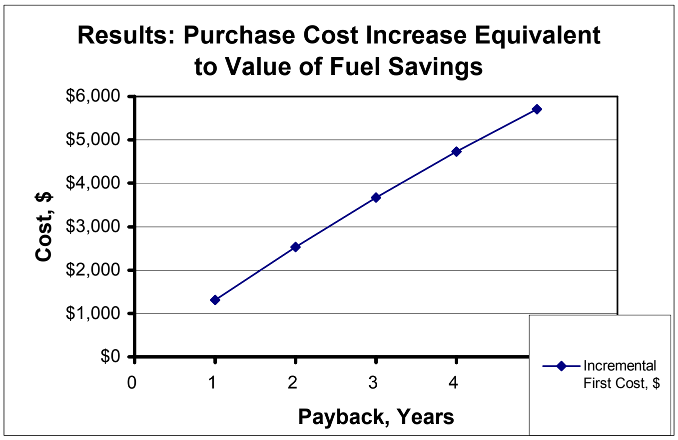

Table 5. Example First-Cost Schedule for Advanced Technologies Type 3 Heavy Trucks

Year	Technology Cost Assumption, $	Two Year Payback Equivalent Cost, $	Comments
2010	2,535	2,535	2-year payback model calculation
2015	3,800	7,606	
2020	6,100	12,116	
2025	5,000	15,000	
2030	3,750	15,000	
2035	3,750	15,000	

Market Segmentation Analysis

As noted above, “Heavy Vehicles” are defined in this analysis as including Classes 3 through 6 (Medium Trucks) and Classes 7 and 8 (Heavy Trucks). The Heavy Truck classes are further subdivided by end-use types—1, 2, and 3. VIUS data were examined for all vehicles in use and vehicles two years old or less. The Heavy Truck vehicle market was parsed by the Analytic Team into these three types—with each having similar use and annual vehicle mile use patterns. The vehicle type segments are:

- Type 1 – multistop, step van, beverage, utility, winch, crane, wrecker, logging, pipe, garbage collection, dump, and concrete delivery;
- Type 2 – platform, livestock, auto transport, oil-field, grain, and tank;
- Type 3 – refrigerated van, drop frame van, open top van, and basic enclosed van.

The lower speed and “stop and start” duty characteristics of Type 1 trucks greatly reduce the potential efficiency benefits of aerodynamic improvements in that sector. For similar reasons, fuel economy improvements due to advanced tires also would be limited for Type 1 vehicles.

As compared to long distance, over the road travel, Type 2 vehicles tend to be used in local or regional delivery; and, as a result, will also realize limited fuel economy benefit from aerodynamic improvements. Distances traveled by Type 2 vehicles are typically greater than Type 1, which makes them a somewhat better market sector for advanced tires.

In general, Type 3 vehicles are the best candidates for both tire and aerodynamic improvement technologies. Refueling characteristics; i.e. central-source refueling or noncentral source also were considered as centrally refueled vehicles would find an alternative fuel source more practical than vehicles that always refuel at road-side facilities.

Heavy vehicle characteristics are summarized in **Table 6**.

Table 6. Heavy-Vehicle Characteristics

Vehicle Type	Average Annual Miles (1)	Fuel Economy (MPG)	Percent Centrally Refueled (1)
Class 3-6	20,126	8.90	40.1%
Class 7 & 8 Type 1	40,043	4.55	59.8%
Class 7 & 8 Type 2	74,066	6.16	41.0%
Class 7 & 8 Type 3	92,434	8.90	42.0%

Note 1: Vehicles 2 years old or less

In the medium-truck market segment (Classes 3 through 6), all vehicle types, with the exception of auto transport, on average, travel about 20,000 miles per year. Heavy trucks, depending on type, travel an average of 40,000 miles to 92,000 miles per year. One of the more interesting findings was the significant difference in fuel economy among the vehicle types with Type 3 heavy vehicles exhibiting an average fuel economy nearly twice as high as Type 1 heavy vehicles (8.90 vs 4.55 MPG).

In addition to the market characterization, historical market penetration data were obtained from VIUS surveys for energy conserving technologies including radial tires, aerodynamic devices, and fan clutches. These data were utilized in the calibration of the rate of efficiency technology adoption in the model (Ref. 1).

Heavy-Vehicle Benefits-Analysis Overview

Initial benefits estimates are generated through the linkage of three spreadsheet models:

- The Heavy Vehicle Market Penetration (HVMP) model
- Integrated Market Penetration And Cost of Transportation Technologies (IMPACTT) model, and
- Heavy Truck Summary (HVS) model.

The relationship of these three models is indicated in **Figure 1**[1].

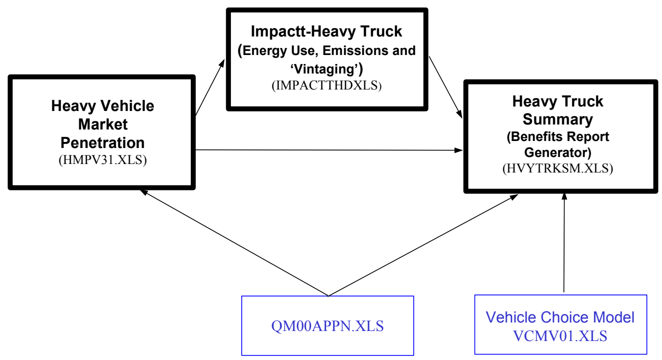

Figure 1.
Heavy-Truck Benefits-Analysis Models

Values for technology performance attributes and cost are input into the Heavy Vehicle Market Penetration (HVMP) model. This includes estimates for current technology fuel economy. Energy prices and projections used in the HVMP are from *AEO 2003*. The HVMP model was developed to estimate the potential market impacts of new technologies on the medium- and heavy-truck market. The results generated by this model are:

- Market penetrations, in units of percent of new vehicles sold for each type and class of vehicle, and

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[1] The Heavy Vehicle Market Penetration Model was developed as a collaborative effort, initially by John Maples of Oak Ridge National Laboratory (ORNL), with assistance from James Moore, of TA Engineering, Inc. Subsequent enhancements have been performed by Moore (TA Engineering).

IMPACTT was originally developed by Marianne Mintz, Argonne National Laboratory (ANL). The version of the model used for the Heavy Vehicle Analyses has been modified by Moore, et al, TA Engineering, with assistance from ANL.

The Heavy Truck Summary Model is a report generating spreadsheet. It was initially developed by Maples, and has subsequently been modified by Analysts at the National Renewable Energy Laboratory, and TA Engineering.

The Quality Metrics Light Vehicle Results Model was developed initially by John Maples, ORNL and has since been modified extensively by Elyse Steiner, NREL and other NREL analysts.

The Vehicle Choice Model is an accounting model developed by Analytic Team members over a period of years.

- Composite fuel economy rating (new mpg) of the vehicles sold.

The market penetration results are supplied through a link to the Impact-Heavy Truck model. This “accounting” and vehicle vintaging model calculates energy savings, criteria and carbon pollution effects, and the rate of market penetration of the new technologies into the entire fleet of Class 3 through 8 trucks.

These interim results are linked to the Heavy Truck Summary model in which various reports of the energy, emissions, and economic benefits attributable to the use of the advanced technologies are calculated. Energy price factors and projections from the Annual Energy Outlook Reference Case are used by the Heavy Truck Summary model to calculate cost savings.

Heavy-Vehicle Market-Penetration Model

The HVMP model market penetration calculation method for Class 7 and 8, Type 1 vehicles is described in **Table A-1** in the appendix. The calculation method for the other three vehicle types and classes is highly analogous.

As discussed above, the HVMP model estimates market penetration, based on cost-effectiveness of the new technology. Cost-effectiveness is measured as the incremental cost of the new technology, less the expected energy savings of that technology over a specified time period in relation to specified payback periods.

Table 7 shows the payback distribution assumed in the HVMP model. This payback distribution was generated from the American Trucking Associations’ survey described above (Ref. 1). The survey found that, for example, 16.4% of the truck operators responding require a payback of one year on an investment.

The new-technology cost and the expected efficiency improvements are exogenous inputs in the model. Energy savings are calculated using the following data and assumptions:

- Annual vehicle miles traveled;
- Fuel efficiency (mpg) without new technology;
- Fuel efficiency (mpg) with new technology; these are specified as multipliers “times” conventional to limit the effort dedicated to estimating future conventional vehicle technology changes.
- Projected fuel price – diesel, ethanol, and CNG, and others as specified by the user. (Ref. 3);
- Incremental cost of new technology over time
- Discount rate; and
- Payback period.

Table 7. Heavy-Vehicle Payback Period Market Distribution

Number of Years	Percent of Motor Carriers
1	16.4%
2	61.7%
3	15.5%
4	6.4%

In the HVMP model, the truck classes are segmented according to refueling location (i.e. central or multiple locations). The data analysis revealed that all vehicle segments have central refueling occurring at least 40% of the time. As vehicles age, central refueling declines. This may be explained by the transition from larger fleet operations to small independent owner operators as centrally refueled vehicles age.

Eleven travel distance categories for medium trucks and 21 for heavy trucks are represented in the model. These categories were determined using travel distributions developed with the VIUS data by ORNL (Ref. 5).

Figure 2 and Figure 3 show the distribution for Centrally and Noncentrally refueled vehicles. Type 3 vehicles display the greatest amount of annual travel of all heavy-vehicle classes. Centrally refueled vehicles travel less per year than non-centrally refueled vehicles. In the noncentrally refueled vehicle segment, the majority of travel occurs from 100,000 to 140,000 miles per year. In the central refueling segment, the majority of travel occurs in a more even distribution between 20,000 and 140,000 miles per year. The technology performance assumptions and truck utilization patterns are used to determine payback performance for the advanced technologies in each type and class of vehicle. The model then calculates composite market penetrations and fuel economy values.

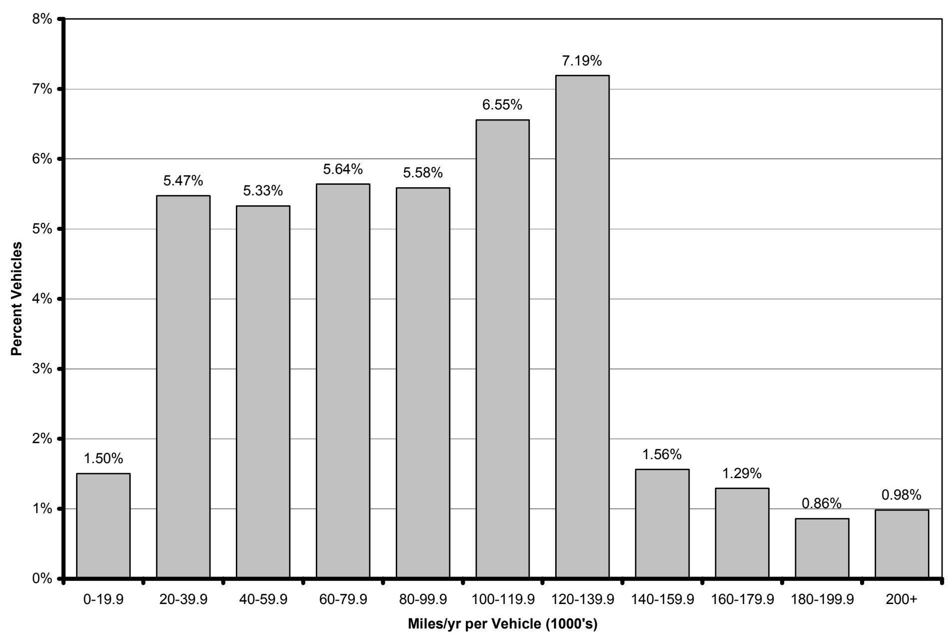

Figure 2. Type 3 Heavy-Vehicle Travel Distribution – Central Refueling

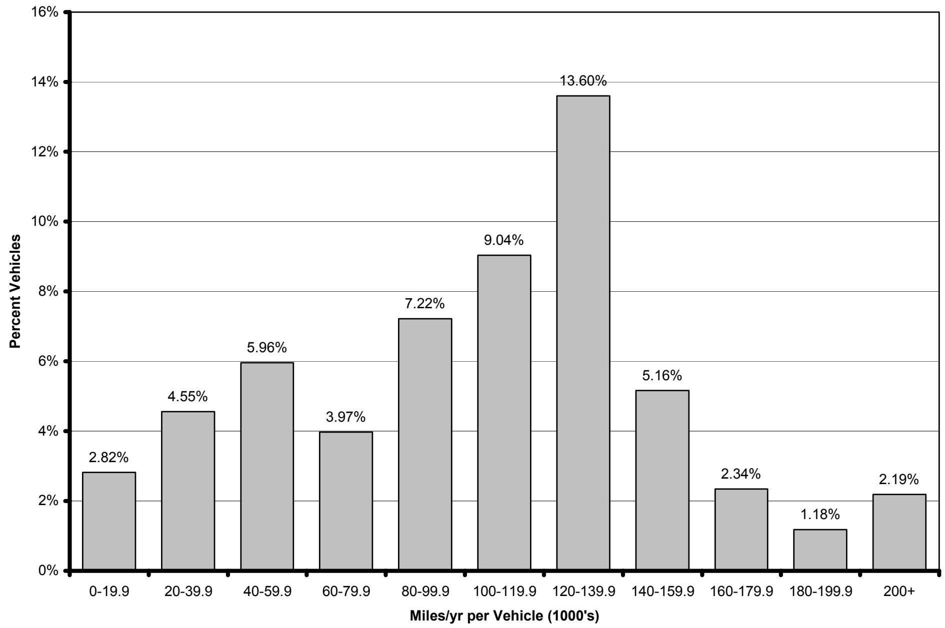

Figure 3. Type 3 Heavy-Vehicle Travel Distribution – Non-Central Refueling

IMPACTT Heavy Truck

This model is a version of the IMPACTT tools developed by M. Mintz of ANL (Ref. 6). Fuel economies and market penetrations determined in HVMP are inputs to this model, which determines initial energy savings due to the expected market penetration of the advanced technologies in Medium and Heavy Vehicles. The model also has the capability of estimating criteria emissions savings, and carbon reduction. In addition, it projects the portions of the Medium- and Heavy-Vehicle *fleet* that are advanced technologies.

Heavy Truck Summary

This report generator provides nine tables of the first-order benefits for the period covering 2000 through 2030.

Specific results are generated for the following:

- Class 3 – 8 Energy and Emissions Reductions
- Technology Market Penetrations
- Sales and Stocks of Advanced Technology Vehicles
- Heavy Vehicle Energy Use, including a breakdown by Class and Technology
- CO_2 Emissions and Emissions Reduction
- NOx, CO, and Non-methane Hydrocarbon Emissions and Emission Reductions, and
- Value of Emissions Reductions (both Carbon and Criteria Pollutants)

Results

Principal results for QM04 analysis are provided in **Tables 8 through 14**. These are reproduced from the Heavy Truck Summary Model.

Table 8. Summary Class 3-8 Energy and Emission Reductions

	Energy Reduction			Alternative	Petroleum	Carbon Reduction			Energy Cost Savings			Incremental
	Total	Class 3-6	Class 7-8	Fuel Use	Reduction	Total	Class 3-6	Class 7-8	Total	Class 3-6	Class 7-8	Vehicle Cost
Year	mmb/d	mmb/d	mmb/d	mmb/d	mmb/d	(MMTCe)	(MMTCe)	(MMTCe)	million 2000$	million 2000$	million 2000$	million 2000$
2000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2006	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2007	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2008	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00
2010	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.000	1.14	1.23	-0.10	13.14
2011	0.000	0.000	0.000	0.000	0.000	0.021	0.013	0.008	10.52	6.46	4.06	42.73
2012	0.002	0.001	0.001	0.000	0.002	0.070	0.028	0.042	35.52	14.18	21.33	75.50
2013	0.004	0.001	0.003	0.000	0.004	0.180	0.052	0.128	91.55	26.63	64.92	127.70
2014	0.010	0.002	0.007	0.000	0.010	0.416	0.105	0.311	209.79	53.01	156.79	230.34
2015	0.020	0.004	0.016	0.000	0.020	0.853	0.179	0.674	431.76	90.63	341.13	354.41
2016	0.038	0.007	0.030	0.000	0.038	1.597	0.315	1.282	805.32	158.70	646.62	527.18
2017	0.063	0.011	0.051	0.000	0.063	2.649	0.485	2.164	1,330.69	243.72	1,086.97	643.21
2018	0.097	0.016	0.081	0.000	0.097	4.085	0.668	3.417	2,053.30	335.81	1,717.49	752.84
2019	0.138	0.020	0.118	0.000	0.138	5.839	0.846	4.993	2,919.44	423.09	2,496.35	864.82
2020	0.193	0.027	0.166	0.000	0.193	8.143	1.136	7.007	4,074.73	568.65	3,506.07	1,066.09
2021	0.257	0.036	0.221	0.000	0.257	10.857	1.507	9.350	5,502.57	763.93	4,738.65	1,129.32
2022	0.328	0.046	0.283	0.000	0.328	13.861	1.923	11.938	7,113.88	986.76	6,127.12	1,184.78
2023	0.405	0.057	0.348	0.000	0.405	17.113	2.411	14.702	8,893.18	1,252.89	7,640.29	1,253.68
2024	0.491	0.071	0.420	0.000	0.491	20.741	3.017	17.724	10,911.68	1,587.13	9,324.55	1,380.44
2025	0.588	0.090	0.498	0.000	0.588	24.814	3.793	21.021	13,213.77	2,019.76	11,194.01	1,546.22
Cumulative Total From Year 2000 to Year												
2005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	(0.00)	-	0.00
2010	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.000	1.14	1.23	(0.10)	13.14
2015	0.037	0.009	0.028	0.000	0.037	1.542	0.380	1.163	780.28	192.14	588.14	843.83
2020	0.565	0.091	0.474	0.000	0.565	23.855	3.830	20.025	11,963.77	1,922.12	10,041.65	4,697.97

Table 9. Market Penetration of Advanced Technologies in Heavy Vehicles

	Class 7-8 Type 1		Class 7-8 Type 2		Class 7-8 Type 3		CLASS 7-8 Final		CLASS 3-6 Final	
Year	CURRENT	ENHANCED	CURRENT	ENHANCED	CURRENT	ENHANCED	CURRENT	ENHANCED	CURRENT	ENHANCED
2000										
2001	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2002	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2003	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2004	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2005	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2006	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2007	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2009	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2010	0.0%	0.0%	0.0%	0.0%	1.5%	0.0%	0.9%	0.0%	1.0%	0.0%
2011	0.0%	0.0%	0.1%	0.0%	4.1%	0.0%	2.5%	0.0%	3.7%	0.0%
2012	0.0%	0.0%	0.3%	0.0%	8.7%	0.0%	5.2%	0.0%	5.1%	0.0%
2013	0.1%	0.0%	1.1%	0.0%	14.7%	0.0%	9.0%	0.0%	8.0%	0.0%
2014	0.6%	0.0%	3.9%	0.0%	23.6%	0.0%	15.0%	0.0%	16.0%	0.0%
2015	1.2%	0.0%	7.1%	0.0%	38.3%	0.0%	24.7%	0.0%	21.6%	0.0%
2016	2.7%	0.0%	13.9%	0.0%	50.2%	0.0%	33.6%	0.0%	35.8%	0.0%
2017	5.1%	0.0%	24.9%	0.0%	59.0%	0.0%	41.7%	0.0%	42.5%	0.0%
2018	11.5%	0.0%	39.0%	0.0%	68.4%	0.0%	51.6%	0.0%	43.2%	0.0%
2019	18.6%	0.0%	47.9%	0.0%	73.8%	0.0%	58.1%	0.0%	48.0%	0.0%
2020	26.1%	0.0%	59.0%	0.0%	83.2%	0.0%	67.6%	0.0%	59.9%	0.0%
2025	58.8%	0.0%	83.3%	0.0%	93.8%	0.0%	85.2%	0.0%	91.2%	0.0%
2030	77.9%	0.0%	91.1%	0.0%	97.3%	0.0%	92.5%	0.0%	91.5%	0.0%

Table 10. Heavy-Vehicle (Class 3-8) Sales and Stocks of Advanced Technology Vehicles

	SALES				STOCKS				STOCKS (Percent of Total)			
	3-6		7&8		3-6		7&8		3-6		7&8	
Year	Current	Enhanced	Current	Enhanced	Current	Enhanced	Current	Enhanced	Current	Enhanced	Current	Enhanced
2000	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2001	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2002	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2003	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2004	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2005	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2006	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2007	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2008	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2009	0	0	0	0	0	0	0	0	0.0%	0.0%	0.0%	0.0%
2010	2,821	0	3,725	0	2,821	0	3,725	0	0.1%	0.0%	0.1%	0.0%
2011	10,609	0	10,688	0	13,421	0	14,401	0	0.3%	0.0%	0.2%	0.0%
2012	14,657	0	22,934	0	28,032	0	37,284	0	0.6%	0.0%	0.6%	0.0%
2013	23,349	0	40,199	0	51,267	0	77,338	0	1.0%	0.0%	1.2%	0.0%
2014	47,315	0	67,318	0	98,343	0	144,317	0	1.9%	0.0%	2.2%	0.0%
2015	64,660	0	111,599	0	162,509	0	255,213	0	3.1%	0.0%	3.8%	0.0%
2016	108,777	0	153,433	0	270,370	0	407,262	0	5.1%	0.0%	5.9%	0.0%
2017	129,299	0	190,497	0	398,018	0	595,210	0	7.4%	0.0%	8.4%	0.0%
2018	133,944	0	240,073	0	529,215	0	830,921	0	9.7%	0.0%	11.5%	0.0%
2019	152,862	0	276,645	0	677,804	0	1,100,473	0	12.1%	0.0%	14.9%	0.0%
2020	197,122	0	332,267	0	868,535	0	1,421,754	0	15.2%	0.0%	18.8%	0.0%
2021	202,378	0	358,164	0	1,061,598	0	1,763,439	0	18.4%	0.0%	23.0%	0.0%
2022	209,864	0	377,989	0	1,258,363	0	2,117,606	0	21.5%	0.0%	27.1%	0.0%
2023	230,553	0	391,394	0	1,471,058	0	2,475,994	0	24.8%	0.0%	31.1%	0.0%
2024	267,897	0	416,901	0	1,715,244	0	2,848,655	0	28.6%	0.0%	35.1%	0.0%
2025	321,741	0	445,358	0	2,006,235	0	3,236,253	0	33.1%	0.0%	39.2%	0.0%
2030	344,643	0	512,589	0	3,384,521	0	5,114,148	0	52.1%	0.0%	56.4%	0.0%

Table 11. Heavy-Vehicle (Class 3-8) Energy Use

Table A-37 Heavy Vehicle (Class 3-8) Energy Use

Year	Base Case Energy Use, Trillion BTUs			Class 3-6 Technology Energy Use, Trillion BTUs			Class 7&8 DOE Program Energy Use, Trillion BTUs	Class 3-8 Current & Enhanced Energy Use	Energy Savings	Energy Savings by Program, Trillion BTUs	
	Class 3-6	Class 7-8	Total	Class 3-6 Conv.	DOE Program	Total	DOE Program	Trillion BTUs	Trillion BTUs	Current Program	Enhanced Program
2000											
2001	839.1	3,815.6	4,654.7	839.1	0.0	839.1	3,815.6	4,654.7	0.0	0.0	0.0
2002	844.9	3,945.3	4,790.2	844.9	0.0	844.9	3,945.3	4,790.2	0.0	0.0	0.0
2003	861.4	4,071.7	4,933.1	861.4	0.0	861.4	4,071.7	4,933.1	0.0	0.0	0.0
2004	872.1	4,152.6	5,024.7	872.1	0.0	872.1	4,152.6	5,024.7	0.0	0.0	0.0
2005	883.9	4,192.1	5,076.0	883.9	0.0	883.9	4,192.1	5,076.0	0.0	0.0	0.0
2006	886.9	4,199.9	5,086.8	886.9	0.0	886.9	4,199.9	5,086.8	0.0	0.0	0.0
2007	895.5	4,233.0	5,128.4	895.5	0.0	895.5	4,233.0	5,128.4	0.0	0.0	0.0
2008	910.0	4,275.0	5,185.1	910.0	0.0	910.0	4,275.0	5,185.1	0.0	0.0	0.0
2009	927.5	4,342.0	5,269.5	927.5	0.0	927.5	4,342.0	5,269.5	0.0	0.0	0.0
2010	947.8	4,420.1	5,367.9	946.7	1.0	947.7	4,420.1	5,367.7	0.1	0.1	0.0
2011	971.7	4,519.7	5,491.4	966.6	4.5	971.0	4,519.3	5,490.4	1.0	1.0	0.0
2012	991.8	4,604.0	5,595.8	981.4	9.0	990.4	4,601.9	5,592.3	3.5	3.5	0.0
2013	1,008.0	4,696.7	5,704.6	989.5	15.9	1,005.3	4,690.3	5,695.6	9.0	9.0	0.0
2014	1,024.1	4,789.8	5,813.9	989.3	29.5	1,018.8	4,774.2	5,793.0	20.8	20.8	0.0
2015	1,041.4	4,888.4	5,929.8	985.0	47.5	1,032.4	4,854.6	5,887.0	42.8	42.8	0.0
2016	1,059.5	4,989.1	6,048.6	966.9	76.8	1,043.7	4,924.8	5,968.6	80.1	80.1	0.0
2017	1,079.9	5,098.6	6,178.5	945.1	110.5	1,055.6	4,990.2	6,045.8	132.8	132.8	0.0
2018	1,101.1	5,210.5	6,311.6	923.6	144.0	1,067.6	5,039.2	6,106.8	204.7	204.7	0.0
2019	1,122.5	5,317.3	6,439.8	897.6	182.5	1,080.1	5,067.0	6,147.2	292.7	292.7	0.0
2020	1,137.9	5,411.0	6,549.0	854.4	226.6	1,081.0	5,059.9	6,140.8	408.1	408.1	0.0
2021	1,184.8	5,542.4	6,727.2	834.5	274.7	1,109.2	5,073.8	6,183.0	544.2	544.2	0.0
2022	1,233.4	5,677.9	6,911.3	814.1	322.9	1,137.0	5,079.5	6,216.5	694.7	694.7	0.0
2023	1,284.3	5,816.7	7,100.9	789.3	374.1	1,163.4	5,079.8	6,243.2	857.7	857.7	0.0
2024	1,337.3	5,959.6	7,296.9	754.0	432.0	1,186.1	5,071.2	6,257.3	1039.6	1,039.6	0.0
2025	1,392.4	6,103.5	7,495.9	701.7	500.6	1,202.3	5,049.9	6,252.2	1243.7	1,243.7	0.0
2026	1,419.5	6,223.0	7,642.6	637.1	556.5	1,193.5	5,002.4	6,195.9	1446.7	1,446.7	0.0
2027	1,447.4	6,344.9	7,792.3	577.0	608.5	1,185.5	4,957.9	6,143.4	1648.9	1,648.9	0.0
2028	1,475.6	6,469.2	7,944.8	521.2	656.8	1,178.1	4,917.1	6,095.2	1849.6	1,849.6	0.0
2029	1,504.6	6,595.9	8,100.5	469.7	701.8	1,171.5	4,877.0	6,048.5	2052.0	2,052.0	0.0
2030	1,534.1	6,725.2	8,259.3	422.4	743.3	1,165.7	4,839.3	6,005.0	2254.3	2,254.3	0.0
Cumulative Total From Year 2000 to Year											
2005	4,301	20,177	24,479	4,301	0	4,301	20,177	24,479	0	0	0
2010	8,869	41,647	50,516	8,868	1	8,869	41,647	50,516	0	0	0
2015	13,906	65,146	79,052	13,780	107	13,887	65,146	78,974	77	77	0
2020	19,407	91,172	110,579	18,367	848	19,215	91,172	109,384	1,196	1,196	0
2025	25,839	120,273	146,111	22,261	2,752	25,013	120,273	140,536	5,576	5,576	0
2030	33,220	152,631	185,851	24,888	6,019	30,907	152,631	171,024	14,827	14,827	0

Table 12. Heavy-Vehicle (Class 3-8) CO2 Emissions and Emission Reductions (1,000 tons)

							OPERATIONAL EMISSIONS			UPSTREAM EMISSIONS					
	Base Case			Technology Case			Reduction			Reduction			TOTAL REDUCTION		
Year	CLS 3-6	CLS 7&8	Total	CLS 3-6	CLS 7&8	Total	CLS 3-6	CLS 7&8	Total	CLS 3-6	CLS 7&8	Total	CLS 3-6	CLS 7&8	Total
2000	63,975	294,947	358,922	63,975	294,947	358,922	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	64,529	302,958	367,486	64,529	302,958	367,486	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	65,113	313,255	378,367	65,113	313,255	378,367	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	66,528	323,294	389,822	66,528	323,294	389,822	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	67,515	329,715	397,230	67,515	329,715	397,230	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	68,614	332,853	401,467	68,614	332,853	401,467	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	69,028	333,470	402,498	69,028	333,470	402,498	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	69,886	336,097	405,983	69,886	336,097	405,983	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	71,127	339,437	410,564	71,127	339,437	410,564	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	72,489	344,755	417,244	72,489	344,755	417,244	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	74,097	350,953	425,050	74,089	350,954	425,043	8.3	-0.8	7.6	0.0	0.0	0.0	8.3	-0.8	7.6
2011	75,963	358,867	434,830	75,919	358,835	434,754	44.1	31.7	75.8	0.0	0.0	0.0	44.1	31.7	75.8
2012	77,535	365,561	443,096	77,436	365,394	442,830	98.5	167.2	265.7	0.0	0.0	0.0	98.5	167.2	265.7
2013	78,802	372,916	451,717	78,616	372,407	451,023	186.0	508.5	694.5	0.0	0.0	0.0	186.0	508.5	694.5
2014	80,060	380,312	460,372	79,685	379,075	458,759	375.7	1,236.9	1,612.6	0.0	0.0	0.0	375.7	1,236.9	1,612.6
2015	81,417	388,140	469,556	80,773	385,456	466,229	644.0	2,683.5	3,327.5	0.0	0.0	0.0	644.0	2,683.5	3,327.5
2016	82,830	396,136	478,966	81,690	391,033	472,723	1,139.6	5,103.8	6,243.4	0.0	0.0	0.0	1,139.6	5,103.8	6,243.4
2017	84,424	404,831	489,255	82,658	396,220	478,879	1,766.0	8,610.4	10,376.4	0.0	0.0	0.0	1,766.0	8,610.4	10,376.4
2018	86,081	413,713	499,794	83,639	400,116	483,754	2,441.9	13,597.6	16,039.6	0.0	0.0	0.0	2,441.9	13,597.6	16,039.6
2019	87,757	422,195	509,952	84,664	402,324	486,988	3,093.1	19,871.0	22,964.1	0.0	0.0	0.0	3,093.1	19,871.0	22,964.1
2020	88,963	429,636	518,600	84,787	401,753	486,540	4,176.2	27,883.8	32,060.0	0.0	0.0	0.0	4,176.2	27,883.8	32,060.0
2021	92,623	440,070	532,692	87,052	402,861	489,913	5,570.8	37,208.7	42,779.5	0.0	0.0	0.0	5,570.8	37,208.7	42,779.5
2022	96,423	450,825	547,247	89,284	403,316	492,599	7,139.2	47,509.1	54,648.3	0.0	0.0	0.0	7,139.2	47,509.1	54,648.3
2023	100,402	461,844	562,245	91,411	403,334	494,745	8,990.2	58,509.7	67,499.9	0.0	0.0	0.0	8,990.2	58,509.7	67,499.9
2024	104,548	473,192	577,740	93,254	402,656	495,910	11,293.6	70,535.9	81,829.5	0.0	0.0	0.0	11,293.6	70,535.9	81,829.5
2025	108,854	484,620	593,474	94,603	400,964	495,567	14,250.8	83,655.9	97,906.7	0.0	0.0	0.0	14,250.8	83,655.9	97,906.7
2030	119,933	533,983	653,916	92,044	384,240	476,285	27,888.5	149,743.1	177,631.7	0.0	0.0	0.0	27,888.5	149,743.1	177,631.7
Cumulative Total From Year 2000 to Year															
2005							0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010							8.3	-0.8	7.6	0.0	0.0	0.0	8.3	-0.8	7.6
2015							1,356.6	4,626.9	5,983.5	0.0	0.0	0.0	1,356.6	4,626.9	5,983.5
2020							13,973.4	79,693.6	93,667.0	0.0	0.0	0.0	13,973.4	79,693.6	93,667.0
2025							61,218.0	377,112.8	438,330.8	0.0	0.0	0.0	61,218.0	377,112.8	438,330.8
2030							174,330.3	999,798.3	1,174,128.6	0.0	0.0	0.0	174,330.3	999,798.3	1,174,128.6

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Appendix

Overview of Heavy Vehicle Market Penetration Model (HVMP)

The HVMP is a spreadsheet model that currently operates in Excel (Office 2000 and associated versions). It consists of nine spreadsheets linked to other models. It is operated by the user specifying inputs and then initiating macros that perform iterative calculations to determine market shares by technology in percents of new vehicle sales. The name and a brief description of each page in the workbook are provided below:

1. **Inputs**—user specifies incremental technology cost and relative fuel efficiency for current and advanced technology(ies). These inputs are specified by year to 2035 and separately for Class 7 and 8 and Classes 3 through 6 vehicles.
2. **Fuel Prices**—array of fuel price information. Typically linked to other AEO-source files.
3. **Market Data (6 pages)**—Distribution of vehicle-use patterns from 1997 VIUS
4. **Type 1 (7 pages)**—Contains macro in which calculations are performed to determine market distribution of conventional and new technologies for “Type 1” Class 7 and 8 vehicles. Calculations are performed separately for centrally refueled and noncentrally refueled vehicles.
5. **Type 2 (6 pages)**—Contains macro in which calculations are performed to determine market distribution of conventional and new technologies for “Type 2” Class 7 and 8 vehicles. Calculations are performed separately for centrally refueled and noncentrally refueled vehicles.
6. **Type 3 (6 pages)**—Contains macro in which calculations are performed to determine market distribution of conventional and new technologies for “Type 3” Class 7 and 8 vehicles. Calculations are performed separately for centrally refueled and noncentrally refueled vehicles.
7. **Med (6 pages)**—Contains macro in which calculations are performed to determine market distribution of conventional and new technologies for “Medium”, i.e., Class 3 through 6 vehicles. Calculations are performed separately for centrally refueled and noncentrally refueled vehicles.
8. **New MPG (2 pages)**—Shows the effect of new technology penetrations on the fleet fuel economy by vehicle class.
9. **Market Penetration (1 page)**—Summarizes the market penetration of new technologies in units of new vehicle sales percentage. Lists market shares for each Class 7 and 8 vehicle type, Class 7 and 8 composite, and Classes 3 through 6 (composite).

Table A-1. Heavy-Vehicle Market-Penetration Model Calculation Methodology

Spreadsheet Location	Description	Comments
Column A	**Year**	Identifies year for which values, calcuations and results are representative.
Columns B - F	**Fuel Economy by Technology**	Values are developed based on baseline technology mpg assumptions and efficiency ratios for advanced technologies.
Column G	**Cost of Alternative Fuel in $/GGE**	Links to Fuel Prices Page
Columns H - I	**Calculates annual savings for 2 alternative technologies**	For Advanced Diesel: (VMT(C10)x$/GGE/Baseline MPG - VMT x $/GGE/Adv. Diesel MPG)
Columns J - M	**Calculates Net Present Value of Savings for 'Advanced Diesel'**	Column J: 1 Year, K: 2 years, L: 3 years; M: 4 years
Columns N - Q	**Calculates Net Present Value of Savings for 'Alternative Fuel Technology'**	Column N: 1 Year, O: 2 years, P: 3 years; Q: 4 years
Columns R - U	**If-then Statement to determine 'Cost Effectiveness Factor' (CEF)**	If NPV of savings is > Cost of Technology, cell value is (cost - NPVSavings)/Cost; Otherwise cell value is 0. Columns are for paybacks of 1, 2, 3, and 4 years.
Column V	**Technology purchase cost 'Alternative Fuel Technology'**	Values are linked to Cost values on 'Inputs' page.
Column W - Z	**Repeats calcuations in Columns R through U for 'Alternative Fuel Technology'**	
Column AA	**If-then Statement to determine 'Technology Adoption Factor' (TAF) for 'Advanced Diesel'**	If 'Cost Effectiveness Factor' for Year 1 PB is 0, cell value = 100; Otherwise (100-((exp(1995 CE Factor-Current Yr. Factor) - 1)/10 x 100)
Column AB	**Continuation of TAF Calculation for Year 1 Payback market**	If AA<0, cell value is 1; Otherwise the Value is the same as AA.
Columns AC + AD	**Repeat AA and AB for 2 year payback market**	
Columns AE + AF	**Repeat AA and AB for 3 year payback market**	
Columns AG + AH	**Repeat AA and AB for 4 year payback market**	
Columns AI - AP	**Repeat Columns AA through AH methodology for 'Alt. Fuel Technology'**	
Column AQ	**If-then statement. Start of Market Penetration for 'Advanced Diesel'**	If AB = 100, then cell value is 0; Otherwise cell value is (1/(1+Abvalue/exp(-2 x Col. R CEF for 1 Year PB))
Column AR	**Same as AQ, but for 2 year PB market.**	
Column AS	**Same as AQ, but for 3 year PB market.**	
Column AT	**Same as AQ, but for 4 year PB market.**	
Column AU	**Final, Step 1; Weighted average market penetration for year 1 through year 4 markets weighting factors**	Weighting factors are based on ATA survey results and are listed at the top of Columns AQ-AT.
Column AV	**Final, Step 2: Reduces Market Penetration to account for market penetration of 'Atl. Fuel Technology' and stay below 100% share.**	=+(AU+(1-BA)*AU)/2
Columns AW - AZ	**Same as columns AQ - AT for 'Alterntive fuel technology'.**	
Column BA	**Final, Step 1; For 'Alt. Fuel Tech.', weighted average market penetration for year 1 through year 4 markets weighting factors**	
Column BB	**Final, Step 2: Reduces Market Penetration to account for market penetration of 'Atl. Fuel Technology' and stay below 100% share.**	
Columns BD - BN	**Macro Results Array-Centrally Refueled Advanced Diesels**	Central1 Macro results are printed in this part of spreadsheet
BO	**Final Step 3: 'Advanced Diesel' (Centrally Refueled) Summation of %VMT that is centrally refueled for the VMT range (e.g. 0-19.9k)* % Market penetration for BD - BN array.**	Results are linked to Market Penetration Page
Columns BQ - CA	**Macro Results Array-Centrally Refueled Alternative Fuels**	Macro results are printed in this part of spreadsheet. Alt Fuel technology only competes in Centrally Refueled Segment
CB	**Final Step 3: 'Alt. Fuel' Summation of %VMT that is centrally refueled for the VMT range (e.g. 0-19.9k)* % Market penetration for BD - BN array.**	Results are linked to Market Penetration Page
Columns CD - CN	**Macro Results Array-Non Centrally Refueled Advanced Diesels**	Macro results are printed in this part of spreadsheet
CO	**Final Step 3: 'Advanced Diesel' (Non-centrally refueled) Summation of %VMT that is centrally refueled for the VMT range (e.g. 0-19.9k)* % Market penetration for BD - BN array.**	Results are linked to Market Penetration Page

Appendix K – GPRA05 Weatherization and Intergovernmental Program Documentation

Introduction

Table 1 outlines the activities characterized for the GPRA 05 Weatherization and Intergovernmental Program. Characterizations and inputs for these activities were provided to EERE as inputs to EERE's integrated modeling effort.

Often such analysis requires the development and use of enabling or simplifying assumptions. In many cases, no citable sources exist for substantiating assumptions. Therefore, assumptions are developed through an iterative process with project managers, project contractors, and GPRA analysts. Often, we base these assumptions on project knowledge and experience, as there are varying degrees of corroborative studies available on which project information can be substantiated, depending on the maturity of the project.

Table 1. Building Technologies Subprograms, Projects, and Activities

Subprogram	Project	Activity
State Energy Program	State Energy Grants	Codes and Standards Energy Audits Rating and Labeling Workshops/Training Incentives Retrofits Loans and Grants Technical Assistance
Weatherization Assistance	Weatherization Assistance	Weatherization Assistance
Gateway Deployment	Rebuild America	Rebuild America Deployment
	Energy Efficiency Information Outreach	Pilot Projects Outreach Activities
	Building Codes Training and Assistance	Building Codes Training and Assistance Deployment
	Clean Cities	Clean Cities Deployment
	Energy Star	Clothes Washers Refrigerators Electric Water Heaters Gas Water Heaters Room Air Conditioners Compact Fluorescent Lamps Dishwashers Windows
	Inventions and Innovation	Inventions and Innovation

1.0 State Energy Program

1.1 State Energy Program

1.1.1 Target Market

Project Description. The State Energy Program provides financial assistance to States, enabling State governments to target their own high priority energy needs and expand clean energy choices for their residents and businesses. With these funds and the resources leveraged by them, the State and Territory Energy Offices develop and manage a variety of programs geared to increase energy efficiency, reduce energy use and costs, develop alternative energy and renewable energy sources, promote environmentally conscious economic development, and reduce reliance on oil produced outside of the United States.

Market Description. The market includes all markets (including buildings, transportation, industry, and power technologies), except new construction and all categories of energy end use.

Baseline technology improvements. For this analysis, the Pacific Northwest National Laboratory (PNNL) did not suggest any changes in technology improvements apart from the Energy Information Administration (EIA) baseline.

1.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered.

- Cleaner air and water
- Increased jobs
- Enhanced national security
- Increased economic competitiveness in world markets
- Mitigation of global warming.[1]

1.1.3 Methodology and Calculations

Inputs to Base Case. PNNL did not provide inputs to change the base case assumptions for the program markets. PNNL's calculations were based on a baseline that was developed from the Energy Information Administration's (EIA's) Commercial Buildings Energy Consumption Survey (CBECS), Residential Energy Consumption Survey (RECS), and the Annual Energy Outlook (AEO). For more information about the methodology used by PNNL, see *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)[4].

Technical Characteristics. For the FY05 GPRA metrics, the State Energy Program (SEP) is characterized, based on the budget request and leveraged funds. Based on the report, *Estimating Energy and Cost Savings and Emissions Reductions for the State Energy Program Based on*

Enumeration Indicators Data (Schweitzer, et al. 2003)[2], eight activities (referred to in the report as program areas) supported by SEP were selected to represent the project. These activities—Codes and Standards, Energy Audits, Rating and Labeling, Workshops/Training, Incentives, Retrofits, Loans and Grants, and Technical Assistance—comprised approximately 98% of the total estimated savings reported. Because the Schweitzer et al study only received responses from 20 states (representing about half of the SEP funding), PNNL assumed that the responses were representative of the whole program, so all indicators produced were multiplied by two to approximate a national total.

Because Schweitzer et al. did not differentiate between funds provided directly by SEP as part of the Formula Grants project and those that SEP administers on behalf of other EERE projects (e.g., Rebuild America, Training and Assistance for Codes) through the Special Projects grants, the methodology was modified in some cases to reduce the likelihood of double-counting the savings estimates. Therefore, outputs resulting from Special Project funding should be allocated to the originating project for purposes of this effort. As an example, outputs resulting from funding that originates in the Training and Assistance for Codes project, but is administered by SEP through Special Projects, should be allocated to Training and Assistance for Codes.

<u>Codes and Standards.</u> Based on the estimated savings contained in Schweitzer et al, PNNL determined that the greatest area of potential overlap between Formula Grants and Special Projects would come about through the Codes and Standards activities. The Schweitzer report provided funding data for each of the activities, with total SEP (Formula Grant and Special Project) funding of about $4 million allocated by the responding states to Codes and Standards activities. Based on information provided by the Building Energy Codes Project on Special Project funding, approximately $1.6 million of that amount would have originated within Training and Assistance for Codes. PNNL determined that codes activities are therefore also being funded out of the SEP Formula Grants, and that some level of savings should be allocated to SEP for codes activities.

For consistency, the estimated savings due to the Codes and Standards activities funded by the SEP were based on the savings estimates produced for the Training and Assistance for Codes project. The Schweitzer et al section on Rating and Labeling cited a study (Feldman and Tannenbaum 2000) indicating that approximately 10% of Energy Star purchases are made as a result of state encouragement. PNNL applied this attribution percentage to the estimate developed for Training and Assistance for Codes, so that the original estimate has been allocated 10% to SEP and 90% to Training and Assistance for Codes.

<u>Energy Audits.</u> In Schweitzer et al, energy-audit calculations were based on three indicators: number of audits, square feet retrofit, and reported savings. For this effort, PNNL converted these three indicators to number of households and square footage of commercial floor space impacted.

Schweitzer et al provided a savings per audit of 6.8 MMBtu per household and 0.0167 MMBtu per square foot of commercial floor space. Based on Tables 1.2.3 and 1.2.4 of the *Buildings Energy Databook*, approximately 83 MMBtu/HH/yr are used by residential space heating and space cooling, yielding a load reduction of 8% for residential space heating and cooling. Based on Tables 1.3.3 and 1.3.4 of the *Buildings Energy Databook*, approximately 126 kBtu/SF/yr are used by commercial space heating, space cooling, and lighting, yielding a load reduction of 13% for commercial space heating, space cooling, and lighting.

To convert the indicators into an estimated number of households, PNNL assumed that each residential audit represented one household, divided the total residential square feet retrofit by the report's assumed average square feet per household (1,600), and divided the estimated reported annual savings by the 6.8 MMBtu/HH figure. This yielded an estimate of approximately 5,500 households impacted by energy audits in any given year. Because the study only received responses from 20 states (representing about half of the SEP funding), that number was multiplied by two to approximate a national total. This yielded a total annual estimate of 11,000 households impacted, or 0.014% of existing residential single-family buildings, in each year.

To convert the indicators into an estimated commercial square footage, PNNL assumed that each commercial audit represented one building multiplied by the average building size assumed in the report (14,500 square feet), used the square footage reported, and divided the estimated reported annual savings by the 0.0167 MMBtu/SF figure. This yielded an estimate of approximately 0.197 billion square feet impacted by energy audits in any given year. As with the residential estimate, the commercial figure was also multiplied by two to approximate a national total, yielding a total annual estimate of 0.396 billion square feet impacted, or 1.576% of existing commercial office, education, and health-care floor space, in each year.

<u>Rating and Labeling.</u> Schweitzer et al provided a national per-device estimate for rating and labeling of approximately 895,400 MMBtu per year. While the report allocated these savings to states (based on population) to determine an estimate of savings for states reporting estimates, the device savings were allocated equally across all states, because no forecast is available for determining which states would fund rating and labeling projects in the future. The equivalent savings per state is about 17,900 MMBtu per device (the national estimate divided by 50).

Of the responding states, two states reported that they funded rating and labeling activities for a total of 82 devices. To convert to a national representation, PNNL assumed that four states would fund rating and labeling activities in any given year, and that each state would cover approximately 40 devices, yielding a total of 160 devices saving energy. PNNL assumed that the savings would be effective for 15 years, and that they were attributable to electricity.

<u>Workshops/Training.</u> An estimate of 13.1% HVAC and 8% lighting savings attributable to workshops and training was provided by Schweitzer et al. PNNL translated these inputs to a 13% load reduction for space heating and space cooling, and an 8% load reduction in lighting within commercial buildings. According to the report, 19 of 20 states funded workshop and training activities, with a total of 5,600 trainees attending and a weighted average of four buildings influenced per trainee. To convert this to a national representation, PNNL assumed that 40 states would fund workshop/training activities in any given year, yielding approximately 11,800 trainees impacting a total of 47,000 buildings. There are currently about 4.7 million existing commercial buildings in the United States.[(3)] PNNL assumed that the relationship between the number of buildings influenced as a percentage of the total stock would be equivalent to the square footage influenced as a percentage of the total commercial square footage; therefore,

workshops and training were assumed to impact approximately 1% of the commercial building stock per year.

Incentives. According to Schweitzer et al, approximately 0.145 MMBtu are saved per rebate dollar. During FY 2000, the ratio of incentive funding to rebate value was approximately 1:39, the percentage of SEP funds spent on incentives within the responding states was 0.31%, and the amount of leveraged funds received for incentives was $1.78 per dollar of funding. Based on the FY 2005 request, PNNL assumed that approximately $355,000 dollars would be spent on incentive activities, equating to about $13.7 million in rebates for an annual savings of almost 2.0 TBtu. PNNL assumed that the savings would be in effect for 15 years.

Retrofits. Within Schweitzer et al, retrofit calculations were based on two indicators: number of retrofits and square feet retrofit. For this effort, PNNL converted these two indicators to number of households and square feet of commercial floor space impacted.

Schweitzer et al provided a savings per audit of 14.51 MMBtu per household and 18.8% per square foot of commercial floor space. Based on Tables 1.2.3 and 1.2.4 of the *Buildings Energy Databook,* approximately 83 MMBtu/HH/yr are used by residential space heating and space cooling, yielding a load reduction of 17% for residential space heating and cooling. PNNL applied the 18.8% savings to commercial space heating, space cooling, and lighting.

To convert the indicators into an estimated number of households, PNNL assumed that each residential retrofit represented one household and divided the total residential square feet retrofit by the report's assumed average square feet per household (1,600). This yielded an estimate of approximately 20,600 households impacted by retrofits in any given year. Because the study only received responses from 20 states (representing about half of the SEP funding), that number was multiplied by two to approximate a national total. This yielded a total annual estimate of 41,000 households impacted, or 0.051% of existing residential single-family buildings, in each year.

To convert the indicators into an estimated commercial square footage, PNNL assumed that each commercial retrofit represented one building multiplied by the average building size assumed in the report (14,500 square feet) and used the square footage reported. This yielded an estimate of approximately 0.028 billion square feet impacted by retrofits in any given year. As with the residential estimate, the commercial figure was also multiplied by two to approximate a national total, yielding a total annual estimate of 0.056 billion square feet impacted, or 0.222% of existing commercial office, education, and health-care floor space, in each year.

Loans and Grants. According to Schweitzer et al, loans average 0.0164 million source Btu per dollar, and grants average 0.0178 million source Btu per dollar. For the GPRA effort, the lower, more conservative value was used for this analysis. During FY 2000, the percentage of SEP funds spent on incentives within the responding states was 21.7%; and the amount of leveraged funds received for incentives was $3.77 per dollar of funding. Based on the FY 2005 request, PNNL assumed that approximately $42.7 million dollars would be spent on loans and grants activities for an annual savings of about 0.001 TBtu. PNNL assumed that the savings would be in effect for 15 years.

Technical Assistance. Within Schweitzer et al, technical assistance calculations were based on the number of recommendations. For this effort, PNNL converted these two indicators to number of households and square feet of commercial floor space impacted.

The report provided a savings per recommendation of 9.0 MMBtu per household and 9.4% per square foot of commercial floor space. Based on Tables 1.2.3 and 1.2.4 of the *Buildings Energy Databook*, approximately 83 MMBtu/HH/yr are used by residential space heating and space cooling, yielding a load reduction of 11% for residential space heating and cooling. PNNL applied the 9.4% savings to commercial space heating, space cooling, and lighting.

To convert the recommendation indicator into an estimated number of households, PNNL assumed that each residential recommendation represented one household. This yielded an estimate of approximately 18,000 households impacted by technical assistance in any given year. Because the study only received responses from 20 states (representing about half of the SEP funding), that number was multiplied by two to approximate a national total. This yielded a total annual estimate of 36,000 households impacted, or 0.045% of existing residential single-family buildings, in each year.

To convert the recommendation indicator into an estimated commercial square footage, PNNL assumed that each commercial recommendation represented one building, and multiplied by the average building size assumed in the report (14,500 square feet). This yielded an estimate of approximately 0.009 billion square feet impacted by retrofits in any given year. As with the residential estimate, the commercial figure was also multiplied by two to approximate a national total, yielding a total annual estimate of 0.017 billion square feet impacted, or 0.069% of existing commercial office, education, and health-care floor space, in each year.

1.1.4 Sources

(1) *FY 2002 Budget Request – Data Bucket Report for State Formula Grants Program*.
(2) Schweitzer, M., D.W. Jones, L.G. Berry, and B.E. Tonn. 2003. *Estimating Energy and Cost Savings and Emissions Reductions for the State Energy Program Based on Enumeration Indicators Data*. ORNL/CON-487, Oak Ridge National Laboratory, Oak Ridge, TN
(3) *2003 Buildings Energy Databook* (internal DOE document). www.buildingsdatabook.eren.doe.gov.
(4) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

2.0 Weatherization Assistance

2.1 Weatherization Assistance

2.1.1 Target Market

Project Description. The Weatherization Assistance Project provides cost-effective energy-efficiency services to low-income constituencies who otherwise could not afford the investment but who would benefit significantly from the cost savings of energy efficiency technologies. The project focuses on households that spend a disproportionate amount of their income for energy, giving priority to households with elderly members, persons with disabilities, and children.

Weatherization Assistance provides technical assistance and formula grants to State and local weatherization agencies throughout the United States. A network of approximately 970 local agencies provide trained crews to perform weatherization services for eligible low-income households in single-family homes, multifamily dwellings, and mobile homes. Of the homes weatherized annually, 49% are occupied by an elderly person with special needs or a person with disabilities. All homes receive a comprehensive energy audit, which is a computerized assessment of a home's energy use and an analysis of which energy conservation measures are best for the home and a combination of those energy-saving measures are installed.

Market Description. The market includes households that are eligible for Federal assistance. Households are categorized as eligible for Federal assistance if the household income is below the Federal maximum standard of 150% of the poverty line or 60% of statewide median income, whichever is higher. Individual States can also set the standard at a lower level than the Federal maximum.[a] Target measures include air sealing; caulking and weather stripping; furnace and boiler tune-up, repair, and replacement; cooling system tune-up and repair; replacement of windows and doors; addition of storm windows and doors; insulation of building shells; and replacement of air conditioners, whole-house fans, evaporative coolers, screening, and window films.[(2)] Weatherization *Plus* expands this strategy to include water heating, refrigeration, lighting, and cooling.[(1)]

Size of Market. About 34 million eligible low-income homes are included in the market.

Baseline technology improvements. For this analysis, PNNL did not suggest any changes in technology improvements apart from the EIA baseline.

2.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. PNNL employed the average household weatherization cost of $1,800[(6)]; this estimate does not include training, technical assistance, and administrative costs. Incremental investment beyond this amount for Weatherization *Plus* homes, estimated at an average of $1,400 by the Weatherization project[(6)], was assumed to be provided by other organizations, that is by leveraged funds. **Table 2** shows the estimated total costs by region for *Plus* homes.

Table 2. Estimated Regional Costs for Weatherization *Plus* Homes

Region	Cost per *Plus* Household
South	$2861
Northeast	$3674
West	$1814
Midwest	$3429

[a] Eligibility requirements for Weatherization Assistance can be found at http://www.eere.energy.gov/weatherization/apply.html

2.1.3 Methodology and Calculations

Inputs to Base Case. PNNL did not provide inputs to change the base case assumptions for the program markets. PNNL's calculations were based on a baseline that was developed from the Energy Information Administration's (EIA's) Commercial Buildings Energy Consumption Survey (CBECS), Residential Energy Consumption Survey (RECS), and the Annual Energy Outlook (AEO). For more information about the methodology used by PNNL, see *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)[7].

Technical Characteristics. For the GPRA metrics, this project was characterized based on an estimated level of savings per household, cost to weatherize each household, budget request, leveraged funds, and an assumed life expectancy of 15 years for weatherization measures. The basic assumptions were derived from a spreadsheet provided by the Weatherization project in September 2001[6]. **Table 3** shows the savings per household used for each region for the FY 2005 metrics.

Table 3. Savings Per Household for the Weatherization Assistance Project

Region	Regular Household Savings (MMBtu/yr)	*Plus* Household Savings (MMBtu/yr)
South	22.25	24.23
Northeast	31.20	46.04
West	19.04	20.31
Midwest	31.20	49.21

The figures in the table were calculated based on the 1997 ORNL meta-evaluation report,[2] the ORNL *Meeting the Challenge* report,[3] and special tabulations from the 1997 "Residential Energy Consumption Survey."[4]

Of the units weatherized in FY 2005, nearly 50% were assumed by the Weatherization Project[3] to have the higher savings rates associated with Weatherization *Plus*. In the *Meeting The Challenge* report,[3] these savings rates were calculated on a regional basis and multiplied times the expected number of *Plus* households in each region.

To develop energy savings by building type, PNNL evaluated historical Weatherization project data in the 1997 ORNL report[2] concerning the types of households weatherized (see **Table 4**).

Table 4. Percent of Weatherized Households by Type

Household Type	% of Weatherized Households
Single Family	64.0%
Mobile Home	20.0%
Multi Family	16.0%

To develop energy savings by fuel type, PNNL also used the historical primary fuel Weatherization project data in the 1997 ORNL report(2). Because the GPRA metrics are reported for electricity, natural gas, and fuel oil (but not for LPG and kerosene), other fuels were allocated within those types based on similarities of emissions. **Table 5** shows the allocation approaches used.

Table 5. Percent of Weatherized Households by Fuel Type

Primary Heating Fuel	% of Weatherized Households	Categorized As
Natural Gas	50.6	Natural Gas
Liquid Propane Gas	13.2	
Fuel Oil	16.0	Fuel Oil
Kerosene	3.2	
Other (includes wood and coal)	7.5	
Electricity	9.5	Electricity

The Department of Energy (DOE) budget and leveraged funding forecasts were used to determine the number of households weatherized in each category (regular or *Plus*) for each of the four regions (South, Northeast, West, and Midwest) based on the weatherization costs per household and assumptions regarding the use of leveraged funds. **Table 6** shows the projection for regular and *Plus* households to be weatherized. PNNL assumed that the number of households weatherized for each category would be constant from 2011 through 2030.

Table 6. Projected Regular and *Plus* Households to be Weatherized

	2005	2006	2007	2008	2009	2010	2011
Total Households	222,395	224,096	225,830	227,599	229,403	231,243	233,119
Regular South	22,703	22,888	23,076	23,267	23,463	23,663	23,867
Regular Northeast	26,778	27,006	27,239	27,476	27,717	27,963	28,213
Regular West	27,177	27,321	27,466	27,615	27,766	27,920	28,077
Regular Midwest	34,538	34,833	35,134	35,441	35,755	36,076	36,403
Plus South	22,703	22,888	23,076	23,267	23,463	23,663	23,867
Plus Northeast	26,778	27.006	27,239	27,476	27,717	27,963	28,213
Plus West	27,177	27,321	27,466	27,615	27,766	27,920	28,077
Plus Midwest	34,538	34,833	35,134	35,441	35,755	36,076	36,403

The number of households in each category was multiplied by the estimated savings level for each category. The estimated savings level for each household category was further divided by household type and then by fuel type. Savings from each household weatherized were assumed to be in effect for 15 years; i.e., savings from households weatherized in 2005 were included in the annual total savings estimates for the years 2005 through 2019.

2.1.4 Sources

(1) *FY 2002 Budget Request – Data Bucket Report for Weatherization Assistance Program* (internal BT document).
(2) Berry, L.G., M.A. Brown, and L.F. Kinney. 1997. *Progress Report of the National Weatherization Assistance Program*, ORNL/CON-450, Oak Ridge National Laboratory, Oak Ridge, Tennessee.
(3) Schweitzer, M. and J.F. Eisenberg. 2000. *Meeting The Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program*. ORNL/CON 479, Draft Analysis, Oak Ridge National Laboratory, Oak Ridge, Tennessee.
(4) Eisenberg, J.F., Oak Ridge National Laboratory. 2001. Special tabulations for the Weatherization Population derived from the 1997 Residential Energy Consumption Survey.
(5) Brown, M.A., L.G. Bery, R.A. Balzer, and E. Faby. 1993. *National Impacts of the Weatherization Assistance Program in Single-Family and Small Multifamily Dwellings*. ORNL/CON-326, Oak Ridge National Laboratory, Oak Ridge, Tennessee.
(6) Eisenberg, J.F., Oak Ridge National Laboratory. 2001. Projections for the Weatherization Assistance Program, provided to PNNL in file “Projections02d230.xls.”
(7) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

3.0 Gateway Deployment

This effort seeks to accomplish effective delivery of the full menu of efficiency and renewable resources aligned with clear community and customer focus. The activities focus on the end-user needs, rather than individual EERE programs. They provide easier access to EERE’s vast array of technologies and resources to ensure they are part of the economic solutions for communities across the country. Through an integrated information and outreach approach, Gateway Deployment facilitates “one-stop” access to a variety of specialized technical and financial assistance.

3.1 Rebuild America

3.1.1 Target Market

Project Description. Rebuild America accelerates energy efficient improvements in existing buildings through community-level partnerships and focuses on K-12 schools, colleges and universities, State and local governments, public and multifamily housing, and commercial buildings. Rebuild America connects people, resources, proven ideas, and innovative practices to solve problems. The project provides one-stop shopping for information and assistance on how to plan, finance, implement, and manage retrofit projects to improve buildings energy efficiency and helps communities find other resources on renewable energy applications, efficient new building designs, energy education, and other innovative energy conservation measures.

Market Description. Rebuild America helps designated communities design and implement energy-saving projects that respond to their own circumstances and goals, providing access to a portfolio of technical assistance, with a core focus on existing commercial and institutional buildings. The general target market includes new and existing multifamily housing;

public/assisted single-family residential units; and commercial buildings, particularly new and existing assembly, health-care, lodging, office, and education buildings.

Market Size.[2] The primary market is the commercial-building sector, which includes nearly 68 billion square feet of building space; however, the five commercial building types that this project targets make up a total of nearly 32 billion square feet. The public assistance[1] and multifamily housing that this project also targets make up an additional 27 billion square feet.

Baseline technology improvements. For this analysis, PNNL did not suggest any changes in technology improvements apart from the EIA baseline.

3.1.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price.

- Cost of Conventional Technology:[4] Average of \$101/ ft^2 for new commercial and multifamily; \$0 for existing buildings.
- Cost of WIP Technology:[1] \$103.00/ ft^2 for new commercial and multifamily; \$3/ ft^2 (2001 to 2009), increasing to \$4/ ft^2 (2010 to 2030) for existing buildings.
- Incremental Cost: 2% above base for new buildings; \$3/ft^2 (2005 to 2009), increasing to \$4/ ft^2 (2010 to 2030) for existing buildings.

Key Consumer Preference/Values – Nonenergy Benefits.[1] The cost and performance characteristics were used to model this project in NEMS-GPRA05/MARKAL-GPRA05. The following nonenergy characteristics were not considered.

- Revitalized neighborhoods and business districts
- Improving school facilities
- Better low-income housing
- Positive economic impact from keeping dollars locally and increasing property values.

3.1.3 Methodology and Calculations

Inputs to Base Case. PNNL did not provide inputs to change the base case assumptions for the program markets.

Technical Characteristics. The project displaces current design/building practices with the target of reducing heating, cooling, water heating, and lighting energy use in retrofitted and new buildings by 25%/ft^2 in 2005 and 40%/ft^2 by 2010.

Technical Potential. Approximately 5 quadrillion Btu in 2005. Total heating, cooling, water-heating, and lighting primary end use for commercial and residential is 23 QBtu and 14 QBtu, respectively. The targeted building types for commercial only represent about 45% total energy consumed and 15% of the total residential energy consumed. The near-term goal is to reduce energy consumption in the targeted buildings by 40%, thus the potential is: (23QBtu x .45 x .40) + (14QBtu x .15 x .40) = 5 QBtu

Expected Market Uptake. PNNL assumed that this activity would not occur in the absence of DOE funding, therefore, no acceleration of market acceptance was modeled. The penetration into the marketplace was calculated within NEMS-GPRA05, based on the price and performance characteristics.

3.1.4 Sources

(1) *FY 2002 Budget Request – Data Bucket Report for Rebuild America Program* (includes Energy Smart Schools and Competitively Selected Community Program) (internal BT document).
(2) Commercial building and multifamily square footage numbers come from AEO 2003.
(3) FY 2003 Data Collection interview with the project manager, Daniel Sze, August 20, 2001.
(4) RS Means Company, Inc. 2002. *"RS MEANS Square Foot Costs"*. 23rd Edition, Kingston, MA.

3.2 Energy Efficiency Information and Outreach

3.2.1 Target Market

Project Description. Energy Efficiency Information and Outreach activities will result in packaged information on appropriate EERE technologies for key market segments, e.g., consumers, homeowners, and school officials.

Market Description. The targeted market segments are primarily existing residential and commercial buildings in all climate zones, with the emphasis in FY 2005 on the residential sector, of which there are approximately 100 million existing household units.(1) The Energy Efficiency Information and Outreach project is a three-pronged effort focused on the funding of Home Performance with Energy Star pilot projects in conjunction with the Environmental Protection Agency (EPA), communication and marketing support for the pilot projects, and for general OWIP communication and outreach focused on a broad range of energy market sectors. The project conceptualizes, plans, and implements a systematic approach to the marketing and communication objectives and evaluation of the projects it supports.

Baseline technology improvements. For this analysis, PNNL did not suggest any changes in technology improvements apart from the EIA baseline.

3.2.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Based on discussions with the program manager, PNNL assumed that the cost of Pilot Projects (the average price per household) would be $5,000—currently, Pilot Project homeowners are spending between $4,000 and $6,000 in retrofits through the Pilot Project program. PNNL assumed that the cost of other outreach activities (the average price per household) would be $1,000, based on discussions with the program manager. In both cases, the cost of conventional technology is $0 because the homeowners are not expected to implement similar activities in the absence of the program.

3.2.3 Methodology and Calculations

Inputs to Base Case. PNNL did not provide inputs to change the base case assumptions for the program markets. PNNL's calculations were based on a baseline that was developed from the Energy Information Administration's (EIA's) Commercial Buildings Energy Consumption Survey (CBECS), Residential Energy Consumption Survey (RECS), and the Annual Energy Outlook (AEO). For more information about the methodology used by PNNL, see *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)[(3)].

Technical Characteristics. As most of the Pilot Project retrofit measures involve the building shell (e.g., insulation, windows), PNNL assumed that these activities primarily impacted the space-conditioning load of existing buildings. Because these retrofits are occurring because of the programmatic builder certification, marketing efforts, and financing options, PNNL assumed that the activity would reap all benefits associated with the retrofits—about a 20% load reduction in space conditioning. Other outreach activities were based on funded projects such as the Home Energy Saver Web site, where consumers can compare their home's energy use with that of an average home in their area and receive information about possible retrofits for their homes. PNNL assumed that consumers visiting such sites and acting on the information were already planning to perform some energy-efficient retrofits to their household, so PNNL assumed that the average incremental space conditioning and water-heating load reduction would be about 5% (e.g., the homeowner was initially interested in replacing the HVAC system, but when provided additional information about other cost-effective energy-saving measures, decided also to add more insulation to the home).

Expected Market Uptake. The penetration rates for Information Outreach Pilot Projects and Other Outreach Activities were developed using a diffusion model based on Fisher and Pry (1971)[(2)]. The equation for determining market diffusion over time is:

$$N(t) = \frac{\kappa}{1 + \exp(-\frac{\ln(81)}{\Delta t}(t - t_m))}$$

Where K = Maximum market share potential

t_m = year in which 50% of potential is reached

Δt = time to grow from 10% to 90% of potential (years)

For pilot projects, k=0.0002%, t_m=17, and Δt=20. For Outreach Activities, k=0.004%, t_m=17, and Δt=20. These values were developed through trial and error to achieve the expected annual household impact in 2005 and in "out" years, based on discussions with the program manager. **Table 7** displays the resulting estimated number of homes impacted based on the penetration curve developed.

Table 7. FY 2005 Market Penetration for Information Outreach Projects

Year	Annual No. Homes – Pilot Projects	Annual No. Homes – Outreach Activities
2005	231	4,620
2006	569	11,383
2007	700	13,998
2008	859	17,184
2009	1,052	21,039
2010	1,284	25,684
2011	1,562	31,240
2012	1,891	37,828
2013	2,279	45,574
2014	2,729	54,573
2015	3,245	64,891
2016	3,828	76,550
2017	4,474	89,478
2018	5,177	103,546
2019	5,927	118,549
2020	6,709	134,175
2021	7,503	150,060
2022	8,291	165,814
2023	9,053	181,051
2024	9,771	195,428
2025	10,434	208,671
2026	11,031	220,620
2027	11,557	231,149
2028	12,010	240,205
2029	12,395	247,896
2030	12,714	254,283

The pilot project activity was assumed not to occur without DOE funding, because it allocates money for builder training and certification, program marketing support, and program-specific financing options; therefore, no acceleration of market acceptance was modeled. Other outreach activities were modeled as an incremental load reduction, above what the homeowner would have done in the absence of the information.

3.2.4 Sources

(1) Discussions with Kyle Andrews, Project Manager, August/September 2003.

(2) Fisher, J.C., and R.H. Pry, (1971) "A Simple Substitution Model of Technological Change." Technological Forecasting and Social Change, 3, 75-88.

(3) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

3.3 Building Codes Training and Assistance

3.3.1 Target Market

Project Description. Building Codes Training and Assistance will provide technical and financial assistance to States to update and implement their energy codes and train approximately 2,000 code officials, designers, and builders to implement these codes. The program will work with three-five pilot States, builder organizations, and financial institutions to provide a package combining builder training, Energy Star promotion, and financing for new and existing homes.

Market Description. The market includes new residential low-rise buildings three stories or less in height, new commercial and multifamily high-rise buildings, and all additions and renovations to buildings requiring code permits.

Size of Market. The commercial market size is about 2 billion ft^2 of new commercial floor space added each year. The Federal sector represents nearly 2.3% overall of new commercial-building construction. Additionally, each year about 1.4 million residential building permits are issued, of which 1 million are for single-family dwellings. Although not all jurisdictions currently have energy efficiency building codes in place, about half of all new residential construction is conservatively estimated to come under building energy code requirements, based on information gathered from state and regional offices by the Building Codes Assistance Program (BCAP). Also, consumers spend approximately 45[b] billion dollars a year on remodeling and renovating projects in private residences, about half of which could potentially be covered by an energy code. One market not covered by codes is manufactured homes, which fall under Housing and Urban Development (HUD) jurisdiction and regulations.

Baseline Technology Improvements. Initial compliance with new codes was assumed to be lower in the base case, i.e., without the Building Energy Codes Project (BECP) than with BECP. Compliance in this context is measured as the percentage of potential savings from the existing code to the updated code. For FY05, the percentage of potential savings, in the first year of the single future code, was assumed to be approximately 20% for envelope measures and 30% for lighting measures without BECP. Ten years after adoption, compliance rates are assumed to increase to 50% for envelope and 60% for lighting. The impact of these compliance percentages varies by state. Some states are assumed to update from the ASHRAE 90.1-1989 standard; others from the ASHRAE 90.1-1999 standard.

3.3.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. Incremental investment costs were developed assuming a five-year payback period on investment (i.e., an annual energy cost savings of $1 implies an initial investment of $5). These

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[b] U.S. Census Bureau (Census). 2000. "1997 Economic Census Construction Geographic Area Series." U.S. Department of Commerce, March 2000. Washington D.C. Located at the following website: http://www.census.gov/epcd/www/97EC23.HTM

estimates were based on a series of benefit-cost studies that examined the energy savings and first-cost impacts of code improvements on seven building prototypes[c].

Key Consumer Preferences/Values. The following nonenergy characteristics were not considered.

- Improved environment and more comfortable buildings.
- Lower utility bills
- Fewer home-maintenance and repair activities
- Reduced pollution due to the reduced burning of fossil fuels and electricity generation, which improves air quality and mitigates the negative impacts of global warming.

3.3.3 Methodology and Calculations

Inputs to Base Case. PNNL did not provide inputs to change the base case assumptions for the program markets. With respect to codes, it is indeterminate as to whether potential future code improvements are incorporated into the NEMS-GPRA05 base case. The NEMS-GPRA05 base case does include some improvements to the building shell efficiency; however, the basis for these improvements (e.g., general building practice improvements, changes in codes requirements, improvements in materials) is not specified by EIA. Codes that have been issued—but that have not gone into effect—may be included in the NEMS-GPRA05 base case, but would not be included in the GPRA forecast of savings for that activity, because it would no longer be funded. Only an estimate of potential future codes is included in the GPRA estimates. For more information about the methodology used by PNNL, see *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (2004)[(7)].

Technical Characteristics: Commercial Buildings. Energy savings from this project result from some basic improvements in the overall energy efficiency of commercial buildings. The present funding for conducting research activities to establish the cost-effective levels of energy codes for new commercial and multifamily high-rise buildings is through the Commercial Buildings Integration subprogram within the Building Technologies Program (BT). The WIP Building Codes Training and Assistance project funds the development of core materials (such as compliance tools and training materials) and provision of training and financial and technical assistance for states to update and implement their building energy codes. Benefits cannot be clearly allocated to either project; thus, the benefits estimated are a function of both training and deployment as well as development of the commercial building energy codes and standards, and the resultant benefits are then allocated between WIP and BT.

Savings estimates for commercial codes are based on increased compliance and accelerated adoption from the ASHRAE 90.1-2004 code and the “next” code assumed to be published in 2007. For FY05, future codes (up through 2010) are assumed to achieve a potential reduction of 18% in electricity and a 10% reduction in natural gas, compared to 90.1-1999. The WIP-funded activities are assumed to increase the initial compliance with these codes to approximately 70% for envelope requirements and 80% for lighting requirements. Adoption is accelerated in the range of five to 10 years, depending on the historical experience with building codes on each

[c] Further information on the series of reports can be found at the Building Energy Codes Web site: http://www.energycodes.gov/implement/tech_assist_reports.stm.

state. Barring future guidance from DOE, benefits for FY 2005 were assumed to be allocated based on the ratio of actual funding levels.

The project's impact is primarily through two avenues: 1) developing and supporting code changes to improve the minimum energy efficiency requirements for commercial and multifamily high-rise buildings and 2) providing technical and financial assistance to states to update and implement their building energy codes. The latter includes developing tools that can ease the adoption of new codes and, through their use, can support improvements in compliance and enforcement of code provisions. Tools take the form of code-compliance software, computer-based training tools for building energy codes, and tools for implementing noncomputer-based codes.

Improvements to building codes are primarily supported by research efforts to review existing codes (conducted by the Building Technologies Program) and specific targeted areas of building energy use and the adoption of code modifications that promote cost-effective reductions in these energy-use areas. Support for the research work has typically taken place in three areas:

- Upgrading ASHRAE/IES Standard 90.1-1989, "Energy Efficient Design of New Buildings Except Low-Rise Residential Buildings"(1)
- Upgrading the Federal commercial and multifamily high-rise building energy code, 10 CFR 434, "Energy Code for New Federal Commercial and Multi-Family High Rise Residential Buildings"(2)
- Upgrading the International Energy Conservation Code (IECC).(3)

The FY 2005 GPRA estimates are based on increased compliance with existing codes, accelerated adoption of the 1999 and 2002 editions of ASHRAE 90.1-1999(4) standard (to comply with Section 304 of the Energy Conservation and Production Act), and the future development of more stringent building energy codes. The energy savings methodology was applied at a state level to better link changes in the codes (e.g., IECC 2003) with variations in climates by states and differences among states in their adoption and enforcement of building codes. The discussion below uses national averages of some of the key assumptions related to adoption and compliance to help summarize the methodology, but appropriate state averages were used in the analysis.

The principal differences among the ASHRAE 90.1-1989, 90.1-1999, and 90.1-2002(5) standards relate to requirements for better windows, reduced installed wattage for lighting, and more efficient heating and cooling equipment. The savings from improved equipment are not included in the project's savings estimates, because they are reflected in the Equipment Standards and Analysis decision unit in this appendix. Based on a series of simulations that include various U.S. locations and that were developed specifically to evaluate the two ASHRAE standards (often referred to as the “determination” study[6]), the average reduction in site energy use was estimated to be about 3.5% or 2 MMBtu/sq ft. The GPRA estimates were partly based on states' accelerated adoption schedule of the ASHRAE 90.1-1999 and 90.1-2002 standards. Through the efforts of the Building Energy Codes project, 35 states were assumed to have adopted the standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of four years nationwide.

The ongoing activities of the ASHRAE 90.1 committee were assumed to lead to more stringent commercial-building standards in the future. DOE was assumed to play a major role in developing the analytical and economic basis for such standards. For the GPRA process, these activities were subsumed in a single upgrade of the ASHRAE standard, assumed to become available in the latter part of the current decade. The GPRA analysis assumed that the overall result of these upgrades is to reduce electricity consumption by 10% and natural gas consumption by 2% in new commercial buildings. Successful state adoption of this standard by 2010 also depends on the project's continuing activities to assist states in the adoption (and compliance) process. Without these activities, the analysis assumed that the same standard would be adopted, on average, six years later.

The project activities were also assumed to improve compliance rates for codes currently adopted by states and localities, as well as future building codes. Compliance is increased through increased familiarity with the codes over time, simplifications to the code while maintaining stringency, and the availability and increased use of compliance tools by builders and enforcement officials. Compliance rates, with and without the project, were estimated for the existing code (a code based on ASHRAE 90.1-1999) and a future standard as discussed above. On a national average basis, compliance with existing codes was estimated at 60% in 2000, increasing to 66% without the project and 79% by 2010 with the project.

The compliance with several key provisions in ASHRAE 90.1-2001 (compared with 90.1-1999) was expected to be higher from the outset. On average, PNNL estimated the compliance to be 65% in the year of the adoption. Ten years later, compliance rates were assumed to increase to 67% without the project and 72% with the project. For buildings that do not comply with the standard, only half of the incremental energy savings were assumed to be achieved by adopting the ASHRAE 90.1-2001 standard.

The analysis assumed that the simplifications in the ASHRAE 90.1-1999 and 90.1-2001 standards will be extended to the new standard and will result in somewhat higher compliance when states first adopt them. Initial compliance was assumed to be about 27% at the time of adoption, increasing to 31% without the project and 73% with the project after the first 10 years. The energy savings in buildings that do not comply with the new standards were assumed to be 65% of that in buildings that comply fully with the code.

Expected Market Uptake: Commercial Buildings. As part of work for an internal analysis of the historical impacts of the Building Codes project in August 2003, the assumptions regarding the acceleration effect of the program were modified (e.g., program activities leading to states adopting codes more rapidly than they would have otherwise). In general, the states were classified into groups that: 1) immediately adopted the ASHRAE 90.1-1989 code, 2) would have adopted within five years without the project, or 3) would have adopted within 10 years without the project. These time periods were then reduced by one year for each successive code after the 1989 code. (Thus, for example, a five-year lag for 90.1-1989 is assumed to fall to three years for the forthcoming ASHRAE 90.1-2004 code). The overall impact of this change was to increase the average lag between the publication of a new standard and when it is adopted—without the Building Codes project. This modified set of assumptions increases the overall estimate of the future energy savings impact from the program.

Technical Characteristics: Residential Buildings. The FY 2005 GPRA estimates are based on increased compliance with existing codes, accelerated adoption of the 2001 and 2003 editions of the International Energy Conservation Code (IECC) code (to comply with Section 304 of the Energy Conservation and Production Act), and the future development of more stringent building codes. The energy savings methodology was applied at a state level to better link changes in the national codes (e.g., IECC 2003) with variations in climate by states and differences among states in their adoption and enforcement of building codes. This discussion uses national averages of some of the key assumptions related to adoption and compliance to help summarize the methodology.

The principal difference between the 1995 Model Energy Code and the IECC 2001 involves the solar heat gain requirements for windows and increased thermal resistance requirements for ducts in unconditioned spaces. Based on a series of simulations for various U.S. locations, the percentage reduction in cooling load was estimated to be about 15%. This requirement increases the heating load by a small amount, about 2% nationally. (The requirement itself is restricted to the southern tier of states). The GPRA estimates were partly based on states' accelerated schedule of adoption of the IECC 2001 and 2003 codes. Through the efforts of the Building Energy Codes project, 31 states were assumed to have adopted the standard by the end of 2005. The project was assumed to accelerate the adoption of the standard by an average of four years nationwide.

The IECC's ongoing activities were assumed to lead to more stringent residential standards in the future. DOE was assumed to play a major role in developing the analytical and economic basis for such standards. For the GPRA process, these activities were subsumed in a single upgrade of the IECC standard, assumed to become available in the latter part of the current decade. Based on discussions with BT staff, PNNL assumed that the results of these upgrades were to reduce heating and cooling loads in new residential structures by 10%. Without these activities, the analysis assumed that the same standard would be adopted, on average, six years later.

Expected Market Uptake: Residential Buildings. The project's activities also were assumed to improve compliance rates for codes currently adopted by states and localities as well as future building codes. Compliance is increased through increased familiarity with the codes, simplifications to the code while maintaining stringency, and the availability and increased use of compliance tools by builders and enforcement officials. Compliance rates, with and without the project, were estimated for various standards as discussed above. As a national average, compliance with existing codes was estimated at 45% in 2003, increasing to 49% without the project and 72% by 2010 with the project.

The compliance with several key provisions in the IECC 2000 and 2003 (compared with the 1995 Model Energy Code) was expected to be higher from the outset. On average, the compliance was estimated to be 68% in the year of the adoption. By 2010, compliance rates were assumed to increase to 69% without the project and 74% with the project. For homes that do not comply with the standard, only half of the incremental energy savings were assumed to be achieved by adopting IECC 2001 or 2003.

The analysis assumed that when states first adopt the new standard assumed to become available in the 2006-2007 time frame, the standard's greater stringency will result in somewhat lower compliance. Initial compliance was assumed to be about 30% at the time of adoption, increasing to 31% without the project and 73% with the project after the first 10 years. For IECC 2001 and 2003, the energy savings in units that do not comply were assumed to be 50% of that in units that comply fully with the code.

3.3.4 Sources

(1) ASHRAE/IES Standard 90.1-1989, "Energy Efficient Design of New Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers and Illuminating Engineering Society.
(2) 10 CFR 434, "Energy Code for New Federal Commercial and Multi-Family High Rise Residential Buildings," *Code of Federal Regulations*, as amended.
(3) International Energy Conservation Code. 2003. International Code Council, Falls Church, Virginia.
(4) ASHRAE/IES Standard 90.1-1999, "Energy Standard for Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers.
(5) ASHRAE/IES Standard 90.1-2002, "Energy Standard for Buildings Except Low-Rise Residential Buildings," American Society of Heating, Refrigeration, and Air-Conditioning Engineers.
(6) U.S. Department of Energy. March 2002. "Commercial Buildings Determinations, Explanation of the Analysis and Spreadsheet (90_1savingsanalysis.xls)." http://www.energycodes.gov/implement/determinations_com.stm
(7) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

3.4 Energy Star

3.4.1 General Target Market

Project Description. Energy Star was introduced by the Environmental Protection Agency in 1992 as a voluntary labeling program designed to identify and promote energy efficient products, with the goal of reducing carbon dioxide emissions. Through its partnership with more than 7,000 private and public sector organizations, Energy Star delivers the technical information and tools that organizations and consumers need to choose energy-efficient solutions and best management practices.

Market Description. The market is determined by the project equipment. For FY 2005, the following residential equipment is characterized:

- Clothes washers
- Refrigerators
- Electric water heaters
- Gas water heaters
- Room air conditioners
- Dishwashers
- Compact Fluorescent Lamps (CFLs)
- Windows

Baseline technology improvements. For this analysis, PNNL did not suggest any changes in technology improvements.

3.4.2 Key Factors in Shaping Market Adoption of EERE Technologies

Key Consumer Preferences/Values and Manufacturing Factors. The following nonenergy characteristics were not considered.

- Increased comfort for residential homeowners
- Decreased time spent changing incandescent lamps
- Water and water-bill savings from higher efficiency dishwashers and clothes washers
- Increased amenities with clothes washers, also decreased time required for dryer cycle
- Higher profits for manufacturers.

3.4.3 General Methodology

Market transformation projects, such as Energy Star, attempt to accelerate market penetration of existing high-efficiency technologies. The information provided by these programs is designed to influence the consumer's awareness of future energy cost savings as compared to the initial cost of the technology. From a modeling standpoint, these efforts are assumed to be represented by a reduction in the consumer's implicit discount rate or hurdle rate. The implicit discount rate for a technology significantly impacts how a consumer determines the present value of the benefits and costs associated with this technology, because it is assumed to capture the perceived risk in the purchase of new products. For Energy Star technologies, most of the costs are incurred at the time the technology is purchased, while most of the energy-saving benefits occur in the future. If the implicit discount rate for a given technology is particularly high, the value a consumer places on these future energy-saving benefits will be low relative to the weight the consumer places on present costs – reflecting the consumer's uncertainty about future benefits. Therefore, to facilitate project modeling, one goal of the Energy Star project is to reduce implicit discount rates by providing additional information about the potential benefits to the consumer.

Within NEMS-PNNL[d], the two modeling parameters determining the implicit discount rate are labeled Beta1 and Beta2[(10)]. Beta1 is used as multiplicative factor with the initial cost of the appliance, and Beta2 is used to multiply the annual energy cost. The sum of the two products (i.e., Beta1 * initial cost + Beta2 * operating cost) is used in the logit specification to yield market shares for each technology. As a rough approximation, the ratio of Beta1/Beta2 can be interpreted as the consumer discount rate for a specific technology. In the residential NEMS-PNNL module, the Beta1 and Beta2 coefficients vary among technologies, as do the resulting discount rates. For example, the implied discount rate for refrigerators is 16%, while the discount rate is estimated to be more than 80% for electric water heaters.

The modifications to the NEMS input file (RTEKTY)—required to estimate energy savings in NEMS-PNNL for each technology in an Energy Star project—are described in the following sections. The assumed reduction in the discount rate (from Energy Star support) is modeled by

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[d] Any modification or alteration to the official NEMS model must be called out as such; for PNNL's effort, the modified version used is referred to as NEMS-PNNL.

reducing the Beta1 parameter. The baseline assumptions made by the EIA, the changes in the Beta1 coefficients, and the resulting changes in the market shares for the most energy-efficient products are documented by technology.

General Expected Market Uptake. PNNL modeled clothes washers, refrigerators, electric water heaters, gas water heaters, room air conditioners, and dishwashers using input from EIA's *Annual Energy Outlook 2001,*[2] based on a project goal of Energy Star appliances achieving 20% of the market share by 2010.

3.4.4 Clothes Washers

3.4.4.1 Target Market

Market Description. This project targets new clothes-washer sales.

3.4.4.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. Modeling the energy savings of clothes washers is complex, because energy can be saved by reducing the consumption of the motor, hot water use, or dryer energy use. The most efficient new technology is the horizontal-axis design, which achieves the bulk of its energy savings by reducing hot water use.

The residential NEMS input file (RTEKTY) includes a column of factors that relate to hot water. The (unitless) factors can be used to adjust the hot water load associated with clothes washers and dishwashers. In preliminary model runs, the values associated with clothes washers appeared to be too low compared with the information supplied by Lawrence Berkeley National Laboratory (LBNL) in support of an efficiency standard for clothes washers. Therefore, these factors were adjusted from 0.67 to 2.00 for vertical-axis machines. The coefficient for the horizontal-axis machine was increased from 0.24 to 0.40. The value for the vertical axis machine was estimated by making runs of the model with and without *any* hot water and observing the resulting energy consumption. The LBNL analysis [11] suggests that 80% to 90% of the energy consumption of clothes washers is attributable to water heating. **Table 8** shows the original and revised NEMS-PNNL inputs for clothes washers.

Expected Market Uptake. With the support of the Energy Star project, the Beta1 parameter, which impacts the resulting market share of each clothes-washer technology, was modified from -0.03811 to -0.0101, based on this product's project goals. **Table 9** shows the market share results of the NEMS-PNNL model runs for clothes washers.

Table 8. Original NEMS and Revised NEMS-PNNL Inputs for Energy Star Clothes Washers

Technology	Start Yr	End Yr	Water Coeff.	Energy Factor	Installed Cost ($)	Type
Original NEMS Inputs						
1	1997	2020	0.67	2.71	90	V-Axis
2	1997	2004	0.67	3.88	645	V-Axis
3	2005	2020	0.67	3.88	590	V-Axis
4	1997	2020	0.24	4.45	800	H-Axis
5	2005	2020	0.24	5.27	800	H-Axis
6	2015	2020	0.24	5.44	800	H-Axis
NEMS-PNNL Inputs						
1	1997	2020	2.0	2.71	490	V-Axis
2	1997	2004	2.0	3.88	645	V-Axis
3	2005	2020	2.0	3.88	590	V-Axis
4	1997	2020	0.4	4.45	800	H-Axis
5	2005	2020	0.4	5.27	800	H-Axis
6	2015	2020	0.4	5.44	800	H-Axis

Table 9. Energy Star Clothes-Washer Market Shares by Technology Estimated by NEMS-PNNL

Census Division	2005		2010	
	Baseline	Energy Star	Baseline	Energy Star
1	0.0000	0.0927	0.0000	0.0923
2	0.0000	0.0904	0.0000	0.0900
3	0.0000	0.0814	0.0000	0.0804
4	0.0000	0.0794	0.0000	0.0794
5	0.0000	0.0813	0.0000	0.0812
6	0.0000	0.0799	0.0000	0.0797
7	0.0000	0.0801	0.0000	0.0791
8	0.0000	0.0831	0.0000	0.0833
9	0.0000	0.0826	0.0000	0.0830
Note: Results shown are for new housing units; replacement shares are generally within 0.5 % of values shown here.				

3.4.5 Refrigerators

3.4.5.1 Target Market

Market Description. This project targets new refrigerator sales.

3.4.5.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. EIA uses four separate models to represent the range of energy efficiencies in the refrigerator market. The first three models are conventional top-mount freezer models with a total capacity of 18 cubic feet. The fourth is a through-the-door model (for water and ice) and does not compete with the first three models. The market share of the through-the-door model is a constant 27% over the forecast horizon. A review of Arthur D. Little's[(3)] (ADL 1998) efficiency and cost forecasts, as well as a recent paper from Oak Ridge National Laboratory[(4)] (ORNL, Vineyard and Sand 1998), suggests some changes to EIA's assumptions used in the *Annual Energy Outlook 2001*[(2)] projection are warranted.

As part of the EIA forecast, the 2001 standard (Model 1) was assumed to yield no increase in cost. **Table 10** shows the EIA efficiency and cost assumptions, which appear to contradict some of the ADL findings. The ADL performance/cost characteristics information suggests that a 460-kWh/yr unit would have an installed cost of $580 to $700. To be conservative, an installation cost of $600 could be assumed. Because a 478-kWh/yr unit is nearly as efficient as the 460-kWh/yr unit, one would expect it would be only negligibly less expensive. Using this logic, the cost of the 478-kWh/yr unit is assumed to be ~$580. These revised assumptions are included in the shaded columns in the table below.

Table 10. Refrigerator Efficiency and Costs: *Annual Energy Outlook 2001*

Model	Initial Year	Ending Year	Annual Consumption (kWh)	Installed Cost ($1998)	Retail Cost ($1998)	Modified NEMS-PNNL Inputs	
						Installed Cost ($1998)	Retail Cost ($1998)
1	1997	2001	690	530.0	480.0	530.0	480.0
1	2002	2020	478	530.0	480.0	580.0	480.0
2	1997	2001	660	550.0	500.0	550.0	500.0
2	2002	2020	460	550.0	500.0	600.0	550.0
3	1993	2001	518	850.0	800.0	850.0	800.0
3	2002	2020	460	550.0	500.0	600.0	550.0
3	2005	2020	400	700.0	650.0	700.0	650.0
4	1993	2001	843	1313.8	1313.8	1313.8	1313.8
4	2002	2020	577	1313.8	1313.8	1313.8	1313.8

The ADL report[(3)] suggests that a 460-kWh/yr model represents a typical model after 2002. A high-efficiency model is specified to consume 400 kWh per year. However, this specification is for a 20-cubic-foot model rather than 18 cubic feet. ADL suggests a cost differential of $100 to $120 between these two models.

Vineyard and Sand (1998)[(4)] add some support to this revision in the cost structure. They start with a "1996 model baseline unit" of 20 cubic feet, which uses 613 kWh/year. The baseline is already 16% more efficient than the 1993 standard (2.01 kWh/day) resulting from the National Appliance Energy Conservation Act.[(5)] From this baseline, they focus on two high-efficiency designs. The most aggressive design would reduce energy by 273 kWh/yr at a retail cost increase of nearly $270. A more cost-effective unit would consume 1.16 kWh/day (423 kWh/yr) at a projected cost increase of $106.

Based on this information, the resulting estimated cost increase of $100 between the 460- and 400-kWh/day units appears to be more reasonable (see Table B-8.4 of the ADL report) than EIA's incremental cost of $150. The ORNL baseline unit is less efficient than the 2001 standard and achieves a 30% energy reduction with a little more than a $100 cost increase. This suggests that the 13% efficiency improvement (460 kWh/day to 400 kWh/day) between models 2 and 3 could be achieved for $100 or less.

Expected Market Uptake. The *Annual Energy Outlook 2001*(2) baseline parameters that determined the market share for high-efficiency refrigerators are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.0229}{-0.1207} \approx implicit\ discount\ rate = 19\%$$

The Energy Star project is assumed to increase the market share of the 400-kWh/yr refrigerator. With the support of the Energy Star project, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.0055}{-0.1207} \approx implicit\ discount\ rate^{E-Star} = 5\%$$

The resulting NEMS-PNNL market shares for Energy Star refrigerators for 2005 and 2010 are shown in **Table 11**.

Table 11. Energy Star Project – Refrigerators (NEMS-PNNL market share of 400-kWh/yr units)

Census Division	2005		2010	
	Baseline	Energy Star	Baseline	Energy Star
1	0.0427	0.2068	0.0426	0.2064
2	0.0409	0.2003	0.0400	0.1971
3	0.0337	0.1727	0.0329	0.1698
4	0.0326	0.1687	0.0327	0.1689
5	0.0342	0.1748	0.0341	0.1744
6	0.0330	0.1702	0.0329	0.1696
7	0.0329	0.1698	0.0322	0.1668
8	0.0355	0.1801	0.0356	0.1805
9	0.0354	0.1793	0.0357	0.1807

3.4.6 Electric Water Heaters

3.4.6.1 Target Market

Market Description. This project targets sales of new electric water heaters.

3.4.6.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. **Table 12** shows EIA's key NEMS inputs for the *Annual Energy Outlook 2001*.[(2)] With these assumed costs, the model projects a zero share for heat-pump water heaters.

Table 12. Key NEMS Inputs for Electric Water Heaters (*Annual Energy Outlook 2001)*

Technology	Start Yr	End Yr	Energy Factor	Installed Cost ($)	Type
1	1997	2020	0.86	350	Resistance
2	1997	2020	0.88	350	Resistance
3	1997	2020	0.95	575	Resistance
4	1997	2020	2.60	1,025	Heat Pump
5	1997	2020	2.00	2,600	Heat Pump
6	2005	2020	0.89	350	Resistance
7	2005	2020	0.96	475	Resistance
8	2005	2020	2.00	900	Heat Pump
9	2015	2020	0.90	400	Resistance
10	2015	2020	0.96	425	Resistance
11	2015	2020	2.20	800	Heat Pump

The Energy Star project was assumed to target high-efficiency electric water heaters with efficiencies exceeding 0.9. As **Table 12** shows, two such units are shown, with efficiencies of 0.95 and 0.96. By 2005, the installed cost of the high-efficiency unit (at the 0.96 efficiency level) is assumed to fall to $475.

Expected Market Uptake. The *Annual Energy Outlook 2001*[(2)] baseline parameters that determined the market share for high-efficiency water heaters are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.01619}{-0.01952} \approx implicit\ discount\ rate = 83\%$$

With the support of the Energy Star project, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.0082}{-0.01952} \approx implicit\ discount\ rate^{E-Star} = 42\%$$

Table 13 shows the specific NEMS-PNNL market share results.

Table 13. NEMS-PNNL Results for Energy Star Electric Water Heaters (national market shares for new single-family homes)

Efficiency Level	2005		2010	
	Baseline	Energy Star	Baseline	Energy Star
0.95	0.0110	0.0540	0.0110	0.0540
0.96	0.0560	0.1280	0.0560	0.1270
Total	0.0670	0.1820	0.0670	0.1810
Note: Results shown are for new, single-family housing units; replacement shares are generally within 2% of the values shown here.				

3.4.7 Gas Water Heaters

3.4.7.1 Target Market

Market Description. This project targets sales of new gas water heaters.

3.4.7.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. Table 14 shows EIA's key NEMS inputs for the *Annual Energy Outlook 2001*.[(2)] The Energy Star project was assumed to promote high-efficiency gas water heaters with energy factors of 0.6 or higher. As Table B-8.8 (in AEO 2001) shows, two such units are shown, with energy factors of 0.6 and 0.63. By 2005, the installed cost of the high-efficiency unit (at the 0.60 energy factor level) is assumed to fall from $400 to $375.

Table 14. Key NEMS Inputs for Gas Water Heaters

Technology	Start Yr	End Yr	Energy Factor	Installed Cost	Type
1	1997	2020	0.54	$340	Noncondensing
2	1997	2020	0.58	$370	Noncondensing
3	1997	2004	0.60	$400	Noncondensing
4	2005	2020	0.60	$375	Noncondensing
5	1997	2020	0.86	$2360	Condensing
6	2005	2014	0.86	$2000	Condensing
7	2015	2020	0.86	$1800	Condensing
8	2005	2014	0.63	$450	Noncondensing
9	2015	2020	0.63	$425	Noncondensing
10	2015	2020	0.70	$500	Noncondensing

Expected Market Uptake. The *Annual Energy Outlook 2001*[(2)] baseline parameters that determined the market share for high-efficiency gas water heaters are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.05393}{-0.1136} \approx implicit\ discount\ rate = 47\%$$

With the support of the Energy Star project, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.0323}{-0.1136} \approx implicit\ discount\ rate^{E-Star} = 28\%$$

Table 15 shows the specific NEMS-PNNL market-share results.

Table 15. NEMS-PNNL Results for Energy Star Gas Water Heaters (national market shares for new, single-family homes)

Efficiency Level	2005		2010	
	Baseline	Energy Star	Baseline	Energy Star
0.60	0.307	0.387	0.315	0.384
0.63	0.011	0.068	0.011	0.066
Total	0.318	0.455	0.326	0.450

3.4.8 Room Air Conditioners

3.4.8.1 Target Market

Market Description. This project targets sales of new room air conditioners.

3.4.8.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. For 2005, EIA assumes that efficiencies of room air conditioners will range from a low of 2.83 COP (seasonal energy efficiency ratio) to a high of 3.52 COP. In the *Annual Energy Outlook 2001*[2] input file for the residential NEMS module, two models were at the low end of this range (COP = 2.83, COP = 2.93), while two models were at the high end of the range (COP = 3.22, COP = 3.43). To achieve a more realistic set of choices, a model with an intermediate efficiency of 3.11 was added and the unit at the 2.93 (COP) level was dropped. The increase in cost to go from a COP of 2.83 to 2.93 was assumed to be $30. **Table 16** shows both the original NEMS input data and the revised NEMS-PNNL data.

The high-efficiency units with a COP >3.4 were assumed to fall under the Energy Star project. In the base case, the combined market share for the units with COPs of 3.43 and 3.52 were less than 1%. The split in market share between the lowest and intermediate efficiency unit (COP = 2.83 and 3.11, respectively) was generally about 75%/25% in favor of the lowest-efficiency model.

Table 16. NEMS-PNNL Input Parameters for Room Air Conditioners

Technology	Start Year	End Year	Seasonal COP	SEER*	Installed Cost
***Annual Energy Outlook 2001* and GPRA Baseline**					
1	1997	2000	2.55	8.70	$450
2	2001	2020	2.83	9.66	$450
3	1997	2004	2.93	10.00	$500
4	2005	2020	2.93	10.00	$490
5	1997	2020	3.43	11.71	$760
6	2005	2020	3.43	11.71	$760
7	2015	2020	3.22	10.99	$600
Revised NEMS-PNNL Inputs					
1	1997	2000	2.55	8.70	$450
2	2001	2020	2.83	9.66	$450
3	1997	2004	3.11	10.61	$530
4	2005	2020	3.11	10.61	$520
5	1997	2020	3.43	11.71	$760
6	2005	2020	3.52	12.01	$760
7	2015	2020	3.22	10.99	$600
*SEER – seasonal energy efficiency ratio.					

Expected Market Uptake. The *Annual Energy Outlook 2001*[2] baseline parameters that determined the market share for high-efficiency room air conditioners are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.0170}{-0.0120} \approx implicit\ discount\ rate > 100\%$$

With the support of the Energy Star project, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.0070}{-0.0120} \approx implicit\ discount\ rate^{E-Star} = 58\%$$

Table 17 shows the specific NEMS-PNNL market share results for the high-efficiency model.

Table 17. NEMS-PNNL Results for Energy Star Room Air Conditioners (national market shares for new, single-family homes)

Census Division	2005		2010	
	Baseline	Energy Star	Baseline	Energy Star
1	0.0083	0.1301	0.0083	0.1299
2	0.0085	0.1323	0.0085	0.1321
3	0.0085	0.1319	0.0084	0.1314
4	0.0084	0.1314	0.0084	0.1312
5	0.0091	0.1396	0.0091	0.1395
6	0.0091	0.1402	0.0091	0.1398
7	0.0101	0.1522	0.0099	0.1501
8	0.0085	0.1327	0.0085	0.1327
9	0.0084	0.1314	0.0084	0.1317

3.4.9 Dishwashers

3.4.9.1 Target Market

Market Description. This project targets sales of new dishwashers.

3.4.9.2 Methodology and Calculations

Inputs to Base Case and Technical Characteristics. The NEMS baseline (*Annual Energy Outlook 2001*)[(2)] data input for 2005 shows three dishwashers, with energy factors 0.46, 0.59, and 0.71. **Table 18** shows the associated costs of these units. Given the cost structure and logit choice parameters, the model suggests that consumers select slightly more than 6% of dishwashers with the 0.59 energy factor and virtually none of the very high=efficiency units.

Table 18. Key NEMS Data Inputs for Dishwashers

Census Division	Initial Yr	Ending Yr	Water Co-Efficiency	Energy Factor	Installed Cost ($)
1	1997	2020	0.80	0.46	350
2	1997	2004	0.80	0.59	500
3	2005	2020	0.80	0.59	450
4	1997	2004	0.78	0.71	700
5	2005	2014	0.78	0.71	600
6	2015	2020	0.78	0.71	500
7	2015	2020	0.80	0.60	400

Expected Market Uptake. The *Annual Energy Outlook 2001*[(2)] baseline parameters that determined the market share for high-efficiency dishwashers are described as follows:

$$\frac{Beta_1}{Beta_2} = \frac{-0.02738}{-0.02413} \approx implicit\ discount\ rate > 100\%$$

With the support of the Energy Star project, the parameters impacting market share were assumed to change in the following manner, based on project goals:

$$\frac{Beta_1^{E-Star}}{Beta_2^{E-Star}} = \frac{-0.01338}{-0.02413} \approx implicit\ discount\ rate^{E-Star} = 55\%$$

Table 19 shows the specific NEMS-PNNL market share results for the two high-efficiency models.

Table 19. NEMS-PNNL Results for Energy Star Project Dishwashers (estimated market shares for high-efficiency dishwashers)

Census Division	2005				2010			
	Baseline		Energy Star		Baseline		Energy Star	
	EF=.59	EF=.71	EF=.59	EF=.71	EF=.59	EF=.71	EF=.59	EF=.71
1	0.0683	0.0012	0.2219	0.0322	0.0682	0.0012	0.2217	0.0321
2	0.0678	0.0012	0.2207	0.0318	0.0677	0.0012	0.2204	0.0317
3	0.0659	0.0011	0.2157	0.0305	0.0656	0.0011	0.2151	0.0304
4	0.0654	0.0011	0.2146	0.0302	0.0654	0.0011	0.2145	0.0304
5	0.0658	0.0011	0.2156	0.0305	0.0654	0.0011	0.2145	0.0304
6	0.0655	0.0011	0.2148	0.0303	0.0658	0.0011	0.2156	0.0305
7	0.0656	0.0011	0.2150	0.0303	0.0653	0.0011	0.2144	0.0302
8	0.0662	0.0011	0.2166	0.0308	0.0663	0.0012	0.2168	0.0308
9	0.0661	0.0011	0.2164	0.0307	0.0663	0.0012	0.2169	0.0308
EF – energy factor.								

3.4.10 Energy Star CFLs

3.4.10.1 Target Market

Market Description. The target market for this technology is residential non-can and non-R-Lamp Edison socket lights, which would not otherwise switch to Compact Fluorescent Lamps (CFLs). Analysis of Energy Star CFLs was based on the program's stated goal of converting 20% of the residential incandescent installed based to high-quality, high-efficiency, ENERGY STAR CFLs.

3.4.10.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. PNNL assumed that the cost of the conventional incandescent technology is $0.75. The cost of the ENERGY STAR CFL is assumed by PNNL to decrease over the study period from approximately $5 per CFL in 2004 to $3 per CFL in 2030.

Baseline market acceptance. In 1998, PNNL conducted a study examining the historical market penetration for 10 energy-efficient products related to the buildings sector. The results of this study are documented in the PNNL report, *Methodological Framework for Analysis of GPRA Metrics: Application to FY04 Projects in BT and WIP* (2003, PNNL-14231). The resulting data were used to develop a set of generic diffusion curves. These curves were used to generate market penetration estimates for projects that do not have a forecast of annual sales targets. For the Energy Star CFL activity, the lighting diffusion curve was used.

3.4.10.3 Methodology and Calculations

Technical Characteristics. Energy Star-qualified CFLs have the efficacies[(6)] shown in **Table 20.**

Table 20. Compact Fluorescent Lamp Efficacies

Lamp Power (Watts) & Configuration	Minimum Efficacy: Lumens/watt (Based upon initial lumen data)
Bare Lamp:	
Lamp power < 15	45
Lamp power >= 15	60
Covered lamp (no reflector):	
Lamp power <15	40
15 >= lamp power < 19	48
19 >= lamp power < 25	50
Lamp power <= 25	55
Reflector Lamp:	
Lamp power < 20	33
Lamp power >= 20	40

Modeling is based on the bare lamp, because reflector lamps represent only about 6% of the shipments of large incandescent lamps, and covered lamps are only a small fraction of the total CFL market. CFLs of 15W and greater can replace incandescent lamps at 75W and above, and were assumed to have an efficacy of 60 lumens/watt. Less than 15W CFLs can replace incandescent of less than 75W and were assumed to have an efficacy of 45 lumens/watt. About 58% of incandescent lamps in homes have wattages less than 75W and 42% of incandescent lamps in homes have wattages 75W and greater[(7)]. The resultant weighted average lumens/Watt for Energy Star CFLs is 51.3 lumens/Watt.

Expected Market Uptake. PNNL assumed that by 2020, in the residential sector, ENERGY STAR CFLs would capture 6.16% of non-can and non-R-lamp incandescent sales (i.e., sales for non-can and non-R-lamp Edison sockets that would not have otherwise converted to CFLs). The 6.16% is based on a market penetration goal of capturing 20% of the installed base. Energy Star CFLs were assumed to penetrate both the high-use part of the market, where 76.4% of the residential lighting energy is consumed (e.g., rooms such as kitchens and living rooms), and the low-use part of the market. Energy Star CFLs were assumed to be put in high-use applications 70% of the time. The sockets in high-use areas (28.4% of the total sockets) will use roughly the same fraction of the lamps (i.e., 28.4% of the sockets consume 76.4% of the lighting energy use). A sales fraction of 6.16% will yield a long-term installed base of 20% of all sockets with 70% of the Energy Star CFLs in high-use sockets and 30% in low-use sockets—i.e., the A-line incandescents that would be present without the Energy Star program. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al) (see **Figure 1**)[e].

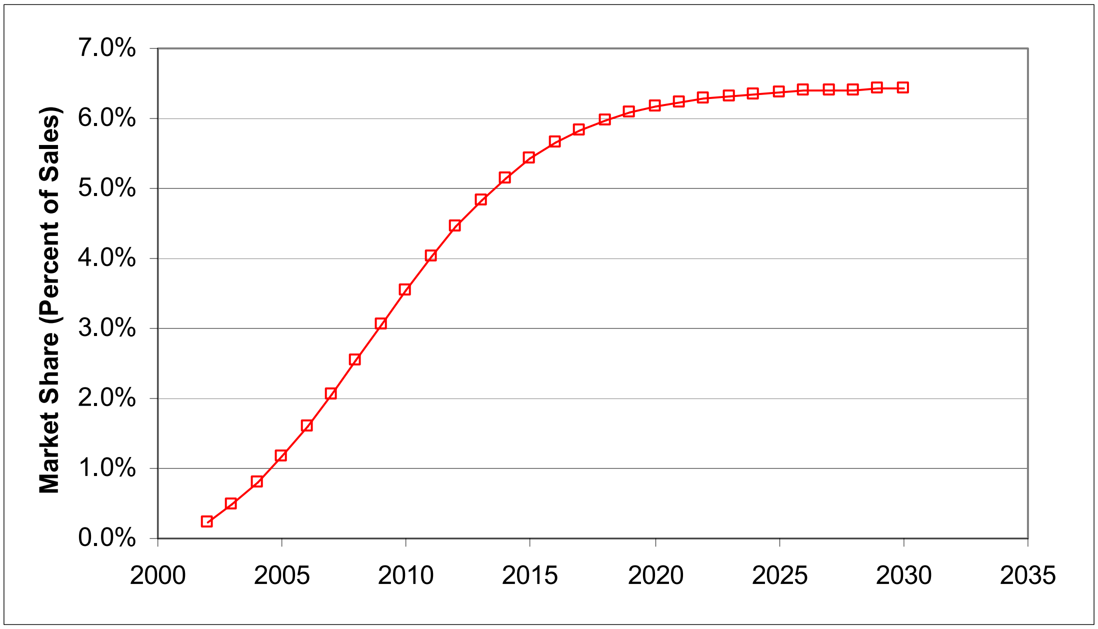

Figure 1. Actual Energy Star CFLs Market Penetration Curve – Percent of Sales to Non-Can, Non-R-Lamp, Incandescents

3.4.11 Windows

3.4.11.1 Target Market

Market Introduction. The technology is commercially available. PNNL assumed that this project would accelerate the penetration in the marketplace by 10 years.

3.4.11.2 Methodology and Calculations

Performance Parameters: Performance parameters are listed in **Table 21**.

Table 21. Performance Parameters for Low-e Windows

Parameter	Value	Units
Shading Coefficient	0.52	Dimensionless
U-value	0.357	Btu/h • ft^2 • °F

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[e] The ENERGY STAR CFLs are assumed to compete only against incandescents (not all Edison sockets). Hence, given that 4.0% of the Edison sockets are already CFLs by 2005 and that it is expected that by 2020 this will increase to 11% without ENERGY STAR, the penetration against incandescents only is somewhat higher than the penetration against all Edison sockets. This curve compensates for the declining incandescent share of the Edison socket market such that the 20% (of all non-can and non-R-lamp Edison sockets that would not have otherwise converted to CFLs) installed base can be achieved.

Performance Target: Performance characteristics vary by building type and climate zone. The estimated savings per building were determined by simulating residential buildings in all climate zones. National impacts were determined using BEAMS (see **Table 22**).

Table 22. Performance Targets for Low-e Windows

	New Buildings		Existing Buildings	
	Heat		Heat	
	North	South	North	South
Single Family	39.73%	66.19%	28.22%	42.54%
Multi Family	75.26%	94.44%	63.73%	84.21%
Mobile Home	44.99%	53.89%	34.16%	39.30%
Assembly	44.88%	76.06%	38.32%	64.07%
Education	41.27%	73.62%	45.36%	66.11%
Food Sales	64.06%	91.69%	59.00%	76.73%
Food Service	66.17%	90.08%	56.17%	80.10%
Health Care	97.69%	99.81%	91.42%	98.22%
Lodging	63.34%	95.42%	55.83%	88.91%
Office-Large	65.00%	85.55%	59.44%	82.17%
Office-Small	50.17%	73.83%	43.72%	72.34%
Merc/Service	57.53%	80.16%	58.11%	75.68%
Warehouse	53.33%	63.84%	14.82%	9.86%
Other	55.83%	86.76%	44.19%	59.20%

	New Buildings		Existing Buildings	
	Cool		Cool	
	North	South	North	South
Single Family	13.95%	16.59%	16.30%	17.38%
Multi Family	1.92%	9.23%	7.35%	11.80%
Mobile Home	22.31%	23.04%	19.26%	19.68%
Assembly	-11.69%	-8.47%	-4.85%	-4.18%
Education	-23.64%	-15.70%	-8.81%	-4.87%
Food Sales	-13.76%	-11.35%	-11.59%	-6.65%
Food Service	-15.38%	-10.65%	-8.14%	-6.10%
Health Care	-21.81%	-12.28%	-19.93%	-13.88%
Lodging	-38.61%	-29.58%	-18.52%	-19.56%
Office-Large	-40.67%	-31.12%	-33.71%	-27.50%
Office-Small	-25.43%	-23.59%	-7.03%	-10.92%
Merc/Service	-24.41%	-17.66%	-17.90%	-10.77%
Warehouse	63.97%	21.01%	47.73%	2.10%

Installed Cost:—Incremental Cost Over Conventional Double-Pane Windows

- 2005: $1.00/ft^2
- 2010: $0.50/ft^2
- 2015: $0.00/ft^2

Expected Market Uptake. The purpose of the program is to increase the penetration of low-e glass from 40% in the residential market and 10% in the commercial market to 100% in both markets by 2020. Both programs, Low-e Market Acceptance and Energy Star Windows (Office of Weatherization and Intergovernmental Programs), form the joint means to achieving the low-e penetration goal – the savings are to be split equally. Penetration curves were developed based on market diffusion curves developed by PNNL and documented in the 2004 PNNL report, *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort* (Elliott, et. al). The "Accelerated" penetration curve represents the percent of superwindow sales with the DOE project; the "Net" penetration curve represents the percent of sales attributable to DOE, as PNNL assumed that the DOE project would accelerate market acceptance by 10 years. The penetration rates are shown in **Figures 2 and 3**. For Low-e Market Acceptance/Energy Star Windows, PNNL assumed that these projects would accelerate the acceptance of this technology in the marketplace by 10 years.

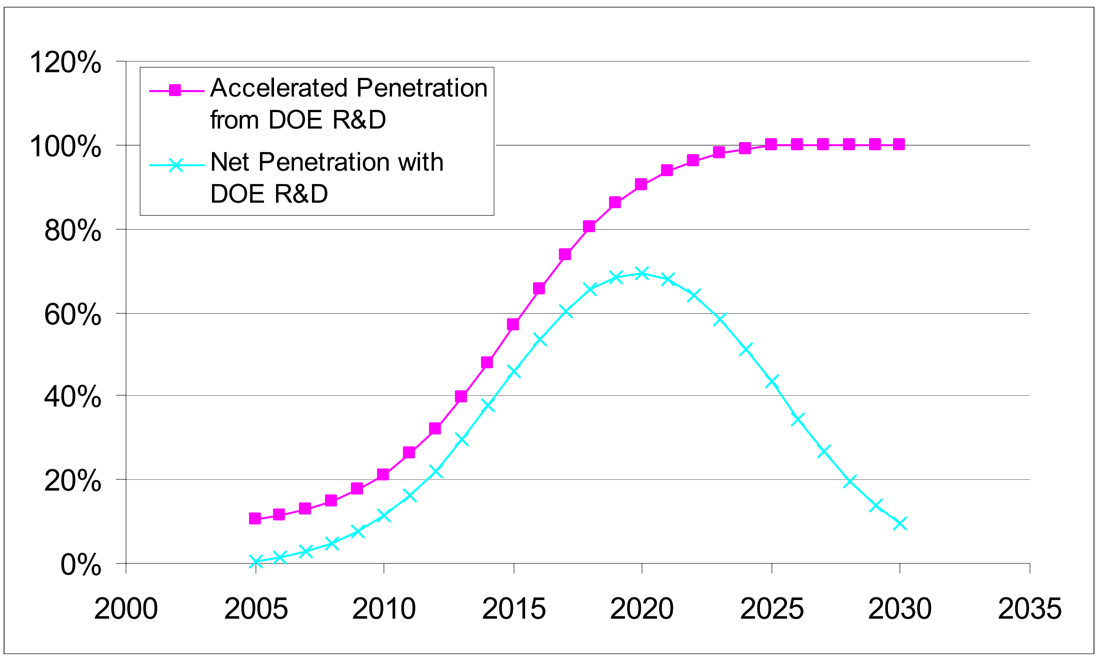

Figure 2. FY05 Low-e Windows – Commercial Buildings Percent of Sales

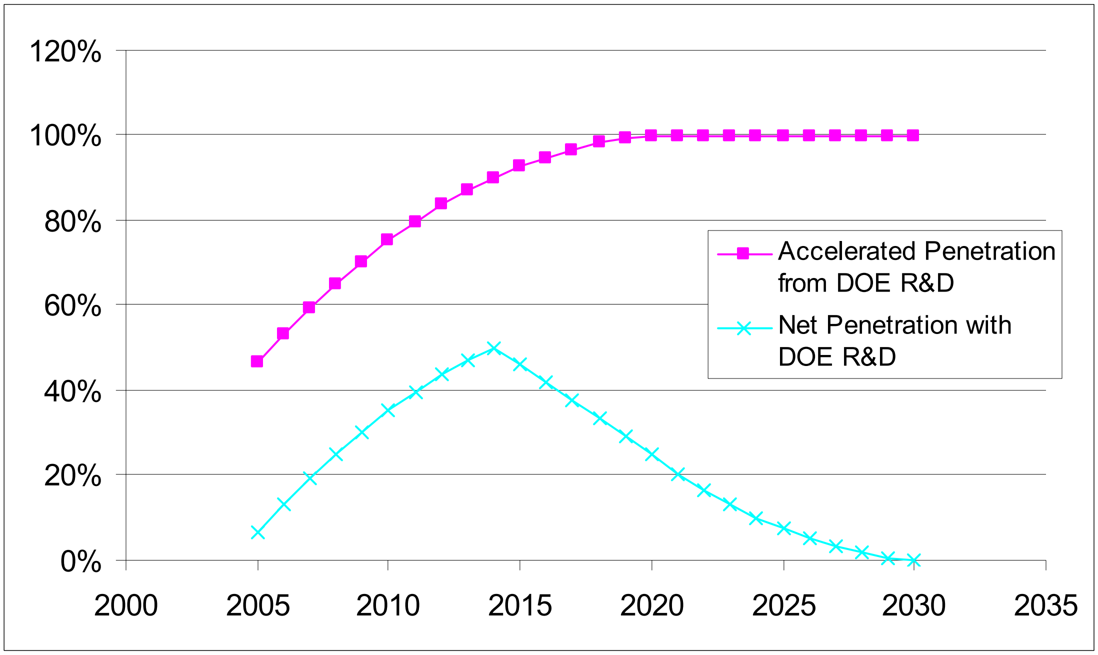

Figure 3. FY05 Low-e Windows – Residential Buildings Percent of Sales

3.4.12 Sources

(1) *FY 2002 Budget Request – Data Bucket Report for Energy Star Program* (internal BTS document).
(2) *Annual Energy Outlook 2001*. 2001. Energy Information Administration, Washington, D.C.
(3) Arthur D. Little, Inc. (ADL). 1998. "EIA Technology Forecast Updates – Residential and Commercial Building Technologies, Reference Case."
(4) Vineyard, E.A. and J.R. Sand. 1998. "Fridge of the Future: Designing a One Kilowatt-Hour/Day Domestic Refrigerator Freezer." In *1998 ACEEE Summer Study Proceedings*.
(5) National Appliance Energy Conservation Act of 1987, Public Law 100-12.
(6) http://www.energystar.gov/products/cfls/EnergyStarCFLSpecification_Final_8.9.01.pdf p.5.
(7) http://eetd.lbl.gov/btp/papers/43782.pdf *Creating Markets For New Products To Replace Incandescent Lamps: The International Experience.* Presented at the 1998 ACEEE Summer Study on Energy Efficiency in Buildings, August 23-28, 1998, Pacific Grove, CA, and published in the Proceedings. Figure 2.
(8) http://enduse.lbl.gov/INFO/LBNL-39102.pdf *Lighting Market Sourcebook for the U.S.*
(9) *FY 2002 Budget Request - Data Bucket Report for Building Envelope: Windows Program* (internal BT document).
(10) *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*. 2003. Energy Information Administration, Washington, D.C. DOE/EIA-M067(2003) http://tonto.eia.doe.gov/FTPROOT/modeldoc/m067(2003).pdf
(11) "Clothes Washer Technical Support Document" source: www.eere.energy.gov/buildings/appliance_standards/residential/clwash_0900_r.html.
(12) Elliott, D.B., D.M. Anderson, D.B. Belzer, K.A. Cort, J.A. Dirks, D.J. Hostick. 2004. *Methodological Framework for Analysis of Buildings-Related Programs: The GPRA Metrics Effort*. PNNL-14697. Pacific Northwest National Laboratory, Richland, Washington.

3.5 Clean Cities

3.5.1 Target Market

Project Description. Clean Cities supports public-private partnerships that deploy alternative fuel vehicles and build supporting infrastructure. Clean Cities works with local businesses and governments to guide them through the process, including goal setting, coalition building, and securing commitments.

Market segment. Clean Cities seeks to displace current conventional gasoline and diesel vehicles with alternative-fuel vehicles and advanced vehicle technologies. It also develops the refueling infrastructure for Alternative Fuel Vehicles (AFVs).

Market size. The total light-vehicle stock is 215 million, including trucks in the Commercial 2B classification. Of the total stock, 17.4 million are fleet vehicles, including Commercial 2B trucks. The Clean Cities Program works largely with fleet managers and buyers, rather than targeting all private consumers, because of the challenges related to building fueling infrastructure. The market for the Clean Cities Program also includes heavy-duty vehicles, such as trucks and buses.

Base case growth: For purposes of an estimate of the number of AFVs attributable to Clean Cities, exogenous to NEMS-GPRA05 modeling, the activity in the alternative-fuel vehicle market was assumed to be very low. In the absence of the Clean Cities Program, the number of AFVs was assumed to grow at 1% per year. The NEMS-GPRA05 base case growth was not changed.

Consistency with EERE baseline: The EERE baseline was used for Clean Cities NEMS-GPRA05 modeling. The exogenous calculations to determine a number of vehicles attributable to the Clean Cities program use a different baseline. For purposes of calculating the number of AFVs attributable to Clean Cities, an AFV growth rate of 1% was assumed to occur in the absence of a Clean Cities program. This was based on expert judgment in consultation with Clean Cities DOE staff, Clean Cities lab analysts, and the Office of Planning, Budget, and Analysis (PBA). This assumption may be compared with the regulatory requirement of EPAct, and with historical growth rates in areas that lack Clean Cities programs. DOE has estimated that the EPAct regulatory requirement results in purchases of approximately 30,000 AFVs per year[f], or about 0.2% of light-duty vehicle sales. However, AEO2003 shows a 10% growth in light-duty AFVs stock between 2000 and 2025. This high level of AFVs in AEO2003 is driven by EPAct regulatory targets that may be higher than expected market performance. Revising this baseline was considered for GPRA FY05, but was not performed because a proposed alternative baseline was not identified.[g] According to the EIA data used for GPRA FY05, non-Clean Cities showed a 2.7% growth rate in numbers of AFVs between 1992 and 2001, so a baseline less than that value is a logical assumption.

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[f] U.S. Department of Energy (2001). "EPAct Fleet Information and Regulations Fact Sheet," DOE/GO-102001-1306, April 2001. Accessed at www.ott.doe.gov/ott/pdf/what_is_epact.pdf. DOE estimates that the EPAct regulatory requirement cause purchases of 20,000-25,000 AFVs per year, according to FR Vol 68, No 42, March 4, 2003, page 10326, "Office of Energy Efficiency and Renewable Energy; Alternative Fuel Transportation Program; Private and Local Government Fleet Determination: Notice of Proposed Rulemaking" Accessed online at www.afdc.doe.gov/pdfs/fr_notice_nopr.pdf.

[g] Personal communication, John Holte, OnLocation. January 22, 2004.

Baseline technology improvements. For this analysis, NREL did not suggest any changes in technology improvements.

Baseline market acceptance. The literature on consumer choice of vehicle technologies has not been reviewed for this project. DOE has developed a variety of detailed models of consumer choice of vehicles. These models include factors such as cost, performance, fuel availability, and other attributes of vehicles that are generally disadvantageous to AFVs. They are not useful for assessing market penetration of technologies whose advantages are primarily environmental, macroeconomic, and national security, such as AFVs. Data such as consumer discount rates have been reported in that literature with regard to vehicle technologies and fuel savings, although there is less specific research on AFVs. For purposes of the Clean Cities baseline market acceptance, no changes were recommended to the NEMS-GPRA05 baseline to reflect these market-acceptance issues. For purposes of calculating the number of AFV sales attributable to Clean Cities, it was assumed that the number of AFVs would increase by 1% per year in the absence of the program.

3.5.2 Key Factors in Shaping Market Adoption of EERE Technologies

Price. AFVs are assumed to cost more than equivalent conventional vehicles throughout the forecast period. Using AEO 2003 estimates, typical price increments for light-duty vehicles are approximately $2,000 for E85 vehicles, $6,000 for CNG vehicles, and $5,000-$6,000 for LPG vehicles. Break-even points vary depending on vehicle, fuel, duty cycle, subsidies, and discount rate. Break-even timing is highly sensitive to fuel-input price. Incremental costs of heavy-duty vehicle technologies were not identified in AEO 2003 data tables. For buses, one source suggests typical incremental vehicle costs of about $20,000-$40,000[h]. Per-mile relative vehicle costs have also been estimated in some studies, and these are highly sensitive to fuel cost and other assumptions.

Key consumer preferences/values. Vehicle-purchase decisions depend on a large number of preferences and values. Many of these are represented in the Transportation Sector Model of NEMS[i]. Some AFV features that may be especially important include:

1. Emissions performance.
2. Type or origin of fuel.
3. Vehicle performance and reliability.
4. Ease and safety of fueling.
5. Ease of maintenance.
6. Regulatory requirements on purchaser.

Of these, consumer preference for emissions performance and fuel origin do not appear to be included in the Transportation Sector Model as consumer values, but are included as regulatory effects on vehicle sales.

[h] General Accounting Office (1999). Mass Transit: Use of Alternative Fuels in Transit Buses. GAO/RCED-00-18. December 1999.

[i] U.S. DOE (2003). "The Transportation Sector Model of the National Energy Modeling System: Model Documentation Report." DOE/EIA-M070(2003). Accessed online at www.eia.doe.gov.

None of these factors were used in estimating the effects of Clean Cities on vehicle purchases exogenous of NEMS-GPRA05.

Manufacturing factors. Manufacturer decisions strongly influence availability of AFVs, and depend on factors such as:

1. Anticipated market size, influenced by extent of fueling infrastructure.
2. Expected vehicle price.
3. Estimated manufacturing costs.
4. Maintenance and warranty issues for manufacturer.
5. Availability of competing investment opportunities.
6. Regulatory requirements on manufacturer.

Some manufacturing factors are included in NEMS, though not at this level of detail. None of these factors were explicitly considered in developing the estimates of vehicle sales attributable to Clean Cities. In addition to vehicle price, NEMS uses maintenance costs, fuel costs, luggage space, fuel economy, range, acceleration, etc. as vehicle attributes in which consumers are interested.

Policy factors. Policy factors are a significant consideration that influences AFV markets, including:

1. EPAct (1992) AFV purchase requirements.
2. EPA vehicle-emissions requirements.
3. Ethanol tax incentives.
4. AFV purchase incentives/rebates.

3.5.3 Methodology and Calculations

Inputs to Base Case. Clean Cities did not provide inputs to change the base case assumptions for the program markets.

Technical characteristics. The technical characteristics of alternative fuels and vehicles were not changed.

Technical potential. The technical potential of AFVs is very large. There is no barrier in vehicle technology that prevents AFVs from capturing 100% of the highway vehicle market. Indeed, vehicles operating on nonpetroleum fuels (electricity, ethanol) were developed early in the history of the motorized vehicle. Based on a vintaging calculation, if modern AFVs had been available and immediately adopted into the market 15 years ago, then market penetration would now be at 70% for automobiles and 68% for trucks, and 85% of all vehicle miles.[j] Assuming that this would displace all petroleum use in heavy-duty vehicles (because the AFVs in that sector use mostly LPG and CNG) and 80% of the petroleum use in light-duty vehicles (because the AFVs in that sector would mostly use E85, which is 80% ethanol by energy content), then AFVs

[j] Davis, S.C; S.W. Diegel (2003). Transportation Energy Data Book: Edition 23. Oak Ridge National Laboratory. ORNL-6970, Tables 3.6 and 3.6.

today would displace 70% of petroleum use in highway vehicles, or about 8 million barrels of petroleum per day.

This sort of estimate does not consider that modern AFVs were not instantaneously available 15 years ago, nor does it factor in very important barriers such as fuel resources, production, and distribution or in vehicle manufacturing. For example, vehicle-manufacturer preference for large-volume production of a single vehicle type has been described, and some estimates of fuel resources and fuel production capacity have been made.

Expected market uptake. In the AEO base case, AFV market penetration is calculated based on the Transportation Sector Model. In the Clean Cities case for FY05 GPRA, additional AFVs attributable to Clean Cities were assumed to replace conventional vehicles, and this revised vehicle population was modeled. The calculation of additional AFVs attributed to Clean Cities is based on historical experience with the effect of Clean Cities on AFV markets, and also on a survey of Clean Cities coordinators to establish their expectations about future program effects.[k] The historical record shows that Clean Cities has been able to achieve growth in the population of AFVs in any given urban area of roughly 5%-18%, while areas not under the Clean Cities program achieved 2.9 percent growth. In a survey, Clean Cities coordinators estimated anticipated market growth at about 8%.

For GPRA FY05, it was assumed that a Clean Cities program would result in an 8% growth rate in AFVs in Clean Cities (starting in 2006)[l] and a 2.9% growth rate (the historic growth rate for 1992-2001) in AFVs in non-Clean Cities (starting in 2004)[m,n]. Eight percent for Clean Cities was selected because it is within the historical range, expectations of Clean Cities coordinators, and aligns with the program funding assumptions for GPRA. The non-Clean Cities growth rate extends the historical rate. NREL assumed that if the program had never existed, AFVs would have experienced a 1% growth rate starting from 1995.[o] In effect, it is assumed that the Clean Cities program began to have an influence on non-Clean Cities growth starting in 1996. This is based on the idea that some of the historical growth in non-Clean Cities may be attributed to Clean Cities, because of the program's impact on the broader market. The difference in number of vehicles between these two cases was used to calculate Clean Cities attributable vehicle stock and annual sales numbers, which provided the input to the NEMS-GPRA05 modeling run.[p]

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[k] Personal Communication, Elyse Steiner, formerly of NREL, January 29, 2004, describing survey by QSS.

[l] Please see spreadsheet, CleanCityInput\Stocks and Flows\column D

[m] Please see spreadsheet, CleanCityInput\Stocks and Flows\column C

[n] The rationale for the numbers that are used for Clean Cities for 2001-2005 is not fully established at this time. The number for 2001(130,000) appears to round off the historical number (133,046). The numbers for 2002-2005 appear to be based on annual program targets for FY03, FY04, and FY05. The numbers for Total AFVs in use for 1999-2001 use data from EIA that was subsequently revised, and the total AFV numbers for 2002-2003 are derived from the historical growth rate between 1998 and 2001.

[o] Please see spreadsheet, CleanCityInput\Stocks and Flows\column E.

[p] Please see spreadsheet, CleanCityInput. This spreadsheet was obtained from John Holte, OnLocation, on January 15, 2004, as a file named CleanCityInputsElyse.

3.6 Inventions and Innovation

The Inventions and Innovation Program (I&I) is a program mandated by Congress to help inventors and very small businesses develop energy-saving technologies. Historically, I&I accepts proposals in two categories. Category 1 proposals are for concept development and have a $40K maximum grant. Category 2 proposals are for prototype testing and further technical development and have a $200K maximum grant.

The I&I program provides an orderly approach to identifying qualified proposals to fund using the steps below:

- Solicitation development
- Proposal evaluation
- Program-relevancy review
- Energy-savings analysis
- Monitoring and tracking
- Commercialization assistance
- Evaluation

Solicitation Development

Generally, changes to the solicitation are minor; but some major changes in emphasis have occurred over the lifetime of the I&I Program. There is more emphasis on the commercialization strategy of the applicant, and each applicant is required to articulate that strategy. Another major change has been the increased documentation of energy-savings methodologies and the definition of the "commercially available unit of production." The applicants are now required to make comparisons to existing commercially available technologies.

Proposal Evaluation

The changes in the solicitation have been designed to make it easier for the reviewer to adequately and fairly judge the invention's energy savings, compared to the savings of existing and commercially available technologies. The technical coefficients (fuel use per year) are approved by the reviewers.

These relatively small grants ($40K-$200K) do not call for the same rigorous market analysis that would occur on much larger grants or continuing programs. However, all grants do undergo a thorough technical and market evaluation.

Program-Relevancy Review

As part of the lengthy selection process, the I&I Program requires the designated EERE program manager to review every proposal within the office's technical scope. This review enables the I&I DOE project manager to eliminate grant proposals that are outside the scope of EERE. It also familiarizes the EERE program managers with potential I&I grants that could potentially segue with their ongoing portfolios.

Energy-Savings Analysis

As I&I conducts a solicitation each year, and the selection of technologies are only bounded by EERE program scope, it is impossible to predict the FY05 program. As a result, the FY04 program is used to estimate the FY05 savings potential.

For the I&I Program, the PNNL GPRA Team analyzes the impact of each selected technology using a model developed for DOE-OIT (Technology Impact Projections Model, Energetics, Inc.) to be applied to industrial technologies considered in the GPRA process. The NEMS-PNNL model, used for most of the analysis in this report, does not have a detailed industrial sector. This generally precludes NEMS-PNNL from being used to model I&I technologies.

The DOE-OIT model only considers the market segment appropriate for a given I&I technology. However, fuel prices, electrical plant heat rates, and environmental emissions rates are taken from EIA forecasts and applied to all technologies. All proposals to I&I contain estimates of current technology performance, the expected performance of the proposed technology, and the suggested market segment. Markets can be defined in terms of annual sales or manufacturing capacity.

Performance estimates are reviewed with the inventor and adjusted for items such as heat rates and fuel mix that differ from the EIA base data. Performance coefficients are prepared for a "Technology Unit" in terms of fuel use per year of operation. For example, a technology unit for the ethanol industry is a production capability of 10,000,000 gallons per year. Multiplying the fuel coefficients by the number of units derives total annual fuel use.

The market segment size is defined in terms of a number of technical units. Initial segment size is based on data from sources such as EIA, trade associations, and DOE industry profiles. Most of the inventors have studied the markets for their technology and offer additional sources and insights. The sector growth rate is derived from similar sources. The inventor proposes a year when the technology would first enter the market, however, when questioned by PNNL, most inventors delay the date from the original proposal.

Maximum market-share limitations are placed on each technology. Factors that limit the share are technology issues, such as the technology will only work on motors more than a certain size; and market issues, such as the technology will be effective only in certain climates. Commercialization plans that use exclusive licensing can limit market share. In a case where two inventors are addressing the same market, the maximum market is cut in half. As I&I technologies either already have intellectual property protection or are in the process of establishing protection, the technology life cycle is set at 15 years. However, to simulate continued program funding at current rates, the life cycle is extended to 2030.

The DOE-OIT model offers four market penetration "s curves." Each is defined in terms of the number of years required to reach 50% of the maximum market share within the defined segment. The choice of "s curve" is based on the new technology performance advantage, the inventor's commercialization plan, the market segment characteristics, and experience of the I&I tracking program for the same segment or type of technology. An inventor that has a development partner who represents a major share of the market segment would be assigned an "s curve" implying a shorter time to reach a 50% of maximum share than an inventor with no partner. Technologies that require large capital investment are given slower "s curves." General instructions supplied to model users are included in **Appendix A**.

Annual estimates of "technology unit" sales and total units installed are made for each technology, based on the above inputs. Energy, economic, and environmental consequences are derived based on the installed unit forecast. The model results are discussed with each inventor and a signed agreement obtained. Generally, model results show fewer units sold than the inventors suggested in their proposals to I&I. A summary of the model results for each technology is part of the I&I Fact Sheets available on the I&I Web site.[q]

Calculations walk-through:

1) Annual market size is calculated from initial market size in "technical units," multiplied by market limitation fractions, and adjusted for market growth.
2) Annual market is multiplied by the market share from the selected "s curve" to derive annual sales.
3) Annual installed capacity is the total sales (to date) in technical units.
4) Energy savings are calculated by fuel type from the difference in performance coefficients between the new and current technology's technical units.
5) Other impacts are calculated from EIA prices and environmental coefficients multiplied by changes in annual fuel use.

Note: The market share is equal to the "s curve" fraction, multiplied by the market share limit fractions. Specific calculation inputs and associated estimates of program benefits are provided in **Appendix B.**

3.6.2 Target Market

Project Description. Descriptions of the activities on which outputs are based are included in **Appendix B**.

Market Description. Market segments are selected from public sources, as appropriate for each I&I technology. OIT's industry profiles are frequently used. Market limitations are introduced to better represent the true target of the technology. EIA forecasts of energy prices and electric power fuel mix are used for all cases.

Baseline market acceptance. The tracking of I&I technology acceptance provides an important input to the selection of the market penetration "s curve" and limitation of ultimate market share.

3.6.3 Methodology and Calculations

Inputs to base case. Because I&I cannot use NEMS-PNNL, each technology has its own base case. The same EIA fuel prices, electric plant fuel mix, and heat rate are used for all cases.

[q] http://www.eere.energy.gov/inventions/

Technical characteristics. Technical coefficients of technology performance (i.e. fuel use per operating unit per year) are provided by the inventor and approved by the proposal reviewers.

Technical potential. The DOE-OIT model can only approximate 100% sales by removing market limitations and using the market penetration curve with five years to 50% of market.

Expected market uptake. The market penetration rate and limits consider many factors. The DOE-OIT model assumes that a technology with equal technical coefficients appears in the market at some time after the technology being evaluated is introduced. Depending on the strength of intellectual property protection, the time lag is usually 10 to 15 years.

Calculation results:
The FY04 grantees' energy savings are used to estimate FY05 results. FY04 had included 13 technologies (grants). Results for six technologies, representing about 85% of program savings, are shown in **Appendix B** to illustrate the I&I's energy-saving impacts. Calculations were made using the above-described OIT model. Sources are noted for market size and growth rates. Comments on the main factors considered in the "s curve" selection appear after the market-penetration percentages.

I&I Appendix A – Market Factor in Technology Impact Projections

The Technology Impact Projections model is used to estimate the potential security, economic, and environmental benefits resulting from research, development, and demonstration projects funded by the Inventions & Innovation Program (I&I). Benefit estimates are critical for evaluating projects and presenting the merits of both individual projects and the overall RD&D portfolio.

Market Inputs

To determine the potential impact of the new technology as it becomes adopted, it is necessary to estimate the total market for the technology, reduce that estimate to the likely actual market, and estimate when (and the rate at which) the new technology will penetrate the market.

Total Market

Total market: the number of units that perform the same task as the proposed technology. Only the domestic U.S. market should be included.

Number of Installed Units in U.S. Market
Please define that market as narrowly as possible: i.e. the smallest group of applications that covers all potential applications for which you may have some data. You may base your estimate on the energy use of the state-of-the-art technology and the energy-use data provided in this package. Other potential data sources include OIT's Energy and Environmental Profile for the relevant industry, EIA's MECS data, or industry sources.

Annual Market Growth Rate
This should be based on an EIA or industry growth projection for the relevant industry.

Market Share

Market share is a function of the potential accessible market share and the likely market share.

Potential Accessible Market Share
The accessible market: The market that the new technology could reasonably access given technical, cost, and other limitations of the technology. For example, certain technologies may be applicable only to a certain scale of plant, certain temperature-range processes, certain types of existing equipment or subsystems, or only certain segments of the industry.

Likely Market Share
In some instances, in addition to technical and cost factors, the technology may compete with other new technology approaches, or with other companies, for the market. Please estimate the likely market share. Use current market-share information, or base estimated market share on the basis of the number of competitors in the market, assuming they are

using different technologies not resulting from this project. This is different than the possibility of "copycats," which should not be considered as competing. That is, if others adopt essentially the same, or slightly modified, technology due to this new technology, that adoption was triggered by the project being described and that project should be "credited" with causing that trend. This is potentially the case for techniques where the intellectual property cannot be, or is not, protected and becomes general knowledge throughout the industry.

Market Penetration

To understand how rapidly the potential impact of the technology will occur, the market penetration of the technology must be projected. This is based on two estimates, the technology development and commercialization timeline, and the market penetration curve.

Technology Development & Commercialization Timeline

The commercial introduction of a technology normally occurs after a significant demonstration or operating prototype and after an adequate test-and-evaluation period, along with allowances for the beginnings of production, dissemination of information, initial marketing and sales, or other "start-up" factors. To capture this lengthy process, please indicate the timeline for developing and introducing the technology into the market. This includes the years for when an initial prototype, refined prototype, and commercial prototype of the technology has or will be completed and the year when the technology will be commercially introduced. An initial prototype is the first prototype of the technology. A refined prototype represents changes to the initial prototype but not a commercially scaled-up version. A commercial prototype is commercial-scale version of the technology. Commercial introduction is when the first unit beyond the commercial prototype is operating. Prototype and commercial introduction years should be consistent with your technology-development program plans.

Market Penetration Curve (Technology Class)

New technologies normally penetrate a market following a familiar "s" curve, the lower end representing the above uncertainties overcome by "early adopters." The curve tails off at the far future, where some may never adopt the new technology. The major portion of the "s" curve, where the new technology is penetrating the market and benefits are being reaped, is the most important. The rate at which technologies penetrate their markets varies significantly: Penetration of heavy industrial technologies generally takes place over decades, while simple process or control changes can penetrate much more rapidly. The actual penetration rate varies. due to many factors including economic, environmental, competitive position, productivity, regulatory, and others.

To assist in "s curve" selection, a large volume of actual penetration rates of past and present technologies were analyzed, normalized, and grouped into five classes, based on a number of characteristics and criteria. Those criteria have been distilled to the five choices in **Table A1.** Analysts and/or applicants can choose either a, b, c, d, or e as the rate class that best fits a given technology. Note that the characteristics (rows) are relatively independent, and a given technology will likely fit best in different classes for different characteristics. Selection of the most likely "rate class" at which the new technology may penetrate the market is based on best judgment and experience. This may be a "subjective average" of the characteristics, or it may be that one or two characteristics are believed to so dominate future adoption decisions that a particular class of penetration rate is justified. There also may be "windows of opportunity" where significant replacements of existing equipment may be expected to occur at some point for other reasons.

For additional assistance, **Table A2** shows actual technologies and the class of their historical penetration rates. Comparison of the new technology (by analogy or similarity) with these examples provides additional insight into selecting the appropriate penetration rate that might be expected for the new technology.

Table A1. Selecting the Market-Penetration Rate Class

Technology/project						**Score (a,b,c,d,e)**
Characteristic	**a**	**b**	**c**	**d**	**e**	
Time to saturation	5 yrs	10 yrs	20 yrs	40 yrs	>40 yrs	na
Technology factors						
Payback discretionary	<<1 yrs	<1 yr	1-3 yrs	3-5 yrs	>5 yrs	
Payback non-discretionary	<<1 yr	<1 yr	1-2 yrs	2-3 yrs	>3 yrs	
Equipment life	<5 yrs	5-15 yrs	15-25 yrs	25-40 yrs	>40 yrs	
Equipment replacement	none	minor	unit operation	plant section	entire plant	
Impact on product quality	$$	$$	$$	$	0/-	
Impact on plant productivity	$$	$$	$$	$	0/-	
Technology experience	new to U.S. only	new to U.S. only	new to industry	new	new	
Industry factors						
Growth (%per annum)	>5%	>5%	2-5%	1-2%	<1%	
Attitude to risk	open	open	Cautious	conservative	averse	
External factors	forcing	forcing	Driving	none	none	na
Gov't regulation						
Other						

Table A2. Penetration Rate of Technologies.

Class	A	B	C	D	E
Aluminum		Treatment of used cathode liners	Strip casting, VOC incinerators		
Chemicals	New series of dehydrogenation catalyst (incremental change)	CFCs -> HCFCs, incrementally improved catalysts, membrane-baed chlor-alkali	Polypropylene catalysts, solvent to water-based paints, PPE-based AN	Synthetic rubber & fibers	
Forest Products			Impulse drying, de-inking of waste newspaper	Kraft pulping, continuous paper machines	
Glass		Lubbers glass blowing, Pilkington float glass	Particulate control, regenerative melters, oxygenase in glass furnaces		
Metals Casting	New shop floor practice				
Petroleum	New series HDS catalysts	Alkylation gasoline	Thermal cracking, catalytic cracking	Residue gasification, flexicoking	

I&I Appendix B – I&I Energy Savings Results

I&I Technology			**Pulse paper drying**			
Technology Description - Virtually all paper manufacturing equipment worldwide is limited by the evaporative drying stage. The most common air-drying process improves efficiency of this process by 59% and speeds overall paper production 21%.						
Market segment is the paper manufacturing industry - technology unit is a plant producing 44,000 tons/yr						
Current technology units in operation - 2002			290	Source - DOE - OIT technology profile		
Sector annual growth rate			1%	Source - DOE - OIT technology profile		
New technology Introduction year			2006			
Savings per new install unit			235 Billion Btu (Natural gas)/year			
Year	2008	2010	2015	2020	2025	2030
Units in service	5	13	78	178	215	227
Annual unit sales	2	4	20	15	4	0
Primary energy savings	1.2	2.9	18.2	41.6	50.3	53.1
(trillion Btu/year)						
Market Penetration	2%	4%	24%	51%	59%	60%
Note: Industry is aware of this technology, but waits for the early adapter. Most plants in the industry are owned by a few companies, success will move quickly although the units are expensive. (10yr curve)						

I&I Technology	**High Speed/ Low Effluent process for Wet and Dry Mill Corn to Ethanol**					
Technology Description - A high speed/low effluent fermentation process based on the BPSC-15 yeast that has the property of forming stable high strength 'pellets'. Very high cell densities are easily attained with this yeast, which leads to quick and complete fermentations Energy use reduced by 42% and requires fewer fermenters for the same production rate.						
Market segment is the ethanol manufacturing industry - technology unit is a plant producing 10,000,000 gal/yr						
Current technology units in operation - 2001			177	Source - EIA's Annual Energy Outlook 2001		
Sector annual growth rate			10%	Source - Energy Bill (5 Billion Gal by 2012)		
New technology Introduction year			2006			
Savings per new install unit			228,000 Million Btu (Coal)/year			
Year	2008	2010	2015	2020	2025	2030
Units in service	6	32	171	284	458	728
Units starting operation	4	17	22	26	42	58
Primary energy savings	1.4	7.3	39.1	64.8	104	166
(trillion Btu/year)						
Market Penetration	2%	8%	25%	26%	26%	26%
Note: Technology can be retrofitted or used with new plants. Retrofit costs are about 5% of original cost, but new plant would see a cost reduction (few fermenting units) in addition to energy savings. (5 yr curve)						

I&I Technology	**Electrochromic Windows - Advanced Processing Technology**					
The project is focused on developing advanced fabrication capabilities for energy-saving electrochromic (EC) smart windows. SAGE EC devices consist of an alt-ceramic stack of thin film coatings on a glass substrate. The window tint can be changed electrically by the application of low voltage DC power. SAGE has developed the basic materials and device technologies and moved operations from laboratory to pilot line.						
Market segment is residential and commercial windows - technology unit is 1 million Sq-meters of glazing						
Current technology units in operation - 2001			3000	Source - Implied from annual sales		
Sector annual growth rate			3%	Source - "Smart Windows" an SRI study		
New technology Introduction year			2005			
Savings per new install unit			304 billion Btu(gas, oil and Elect) /year			
Year	2005	2010	2015	2020	2025	2030
Units in service	11	106	617	1287	1638	1896
Units sold	11	37	147	103	58	34
Primary energy savings	3.6	32.4	182.5	375.3	477.5	552.8
(trillion Btu/year)						
Market Penetration	0%	3%	14%	25%	28%	28%
Note: Early years sales based on SRI markets study with later years keyed to LBNL saturation estimates referenced by the inventor.(10yr curve)						

I&I Technology	**Multi-rotor Micro Particle Generator**					
This mechanical generator incorporates a novel approach to continuous emulsification processing of any type of fine particle homogeneous suspensions. Through exceptionally efficient and effective particle size reduction or, in the case of organic materials, cell disruption, thus greater starch exposure. This process eliminates the current Jet Cooking process used to reach the "liquefaction stage" in the production of corn ethanol, saving up to 46% of the related energy costs.						
Market segment is the ethanol manufacturing industry - technology unit is a plant producing 10,000,000 gal/yr						
Current technology units in operation - 2001			177	Source - EIA's Annual Energy Outlook 2001		
Sector annual growth rate			10%	Source - Energy Bill (5 Billion Gal by 2012)		
New technology Introduction year			2004			
Savings per new install unit			37,400 Million Btu (Coal)/year			
Year	2005	2010	2015	2020	2025	2030
Units in service	2	77	176	284	458	728
Units sold	1	28	17	26	42	58
Primary energy savings	0.1	2.9	6.7	10.9	17.6	28.0
(trillion Btu/year)						
Market Penetration	1%	19%	26%	26%	26%	26%
Note: Basic technology exists, but has not been applied to corn. After testing and any necessary modifications units can be sold to new or retrofitted to existing plants. (5yr curve)						

I&I Technology	**High Efficiency Variable Dehumidification for Air Conditioners**					
The project goal is to produce a production prototype that will lead industry to a highly marketable improvement in energy efficiency, dehumidification, and maintenance of like-new performance for unitary air-conditioning and dehumidification.						
Market segment is Commercial and Residential AC - technology unit delivers 20,000 ton-hr/year						
Current technology units sales - 2002			5.42 million	Source - ADL report for OBT		
Sector annual growth rate			2%	Source - ADL report for OBT		
New technology Introduction year			2006			
Savings per new install unit			142 Million Btu (Electricity)/year			
Year	2005	2010	2015	2020	2025	2030
Units in service	0	108,198	700,628	1,683,669	2,138,463	2,371,813
Units sold	0	38,179	186,332	156,923	63,456	20,493
Primary energy savings	0.0	11.6	68.9	158.1	201	223
(trillion Btu/year)						
Market penetration		2%	10%	22%	25%	25%
Note: Technology requires major AC unit design changes, but with result little or no cost increase. Market is limited to regions with high humidity- Southeast and portions of South and Midwest. (10yr curve)						

I&I Technology	**Medium Voltage Energy Saving Motor Controller**					
Concept for a medium voltage electric motor controller that cost-effectively reduces energy consumption by up to 35% for underloaded medium voltage (2300-4600V) electric motors. While large electric motors comprise only 0.3% of the number of motors used in US manufacturing, they consume 19% of the total motor energy. When a motor is loaded less than 40% of its full load, its efficiency declines quickly.						
Market segment is Electric motors - technology unit a 1000 HP motor running at part load						
Current technology units sales - 1997			89,500	Source - DOE Motor Challenge data		
Sector annual growth rate			3%	Source - DOE Motor Challenge data		
New technology Introduction year			2006			
Savings per new install unit			4,466 Million Btu (Electricity)/year			
Year	2005	2010	2015	2020	2025	2030
Units in service	0	1123	3747	11363	26365	46524
Units sold	0	245	787	2149	3775	3825
Primary energy savings	0	5.0	15.3	44.4	103.0	181.7
(trillion Btu/year)						
Market Penetration	0%	1%	2%	6%	13%	20%

Note: Market is limited to motors over 200HP that operate at less the 40% of full load. The inventor already supplies controllers for smaller motors. Research will develop capability for larger motors. The inventor company knows the industry and provided market forecasts based on his own experience.(20yr curve)						

Appendix L – GPRA05 Wind and Hydropower Technologies Program Documentation

Description of GPRA05 Benefits Methodology for Wind

The wind energy component of the Wind and Hydropower Technologies Program seeks to reduce the cost and improve the performance of wind technology, and to reduce barriers to its use. The GPRA benefits are based primarily on model projections of the market share for wind technologies, based on their economic characteristics. This document describes the assumptions that are used by the models to calculate those benefits.

Market Segments

Wind energy is expected to penetrate in two market segments: the least cost (competitive bulk power) power market and the green power market. Through program-sponsored research, wind technology is projected to improve significantly during the next decade. This improvement is represented in the GPRA05 modeling effort by a declining capital cost trajectory, lower O&M costs, and increased performance. The values used for the wind technology cost and performance projections are consistent with the program's 2012 cost of energy goals for low wind-speed technology.

In addition to competing on an economic basis with other electricity generation technologies, wind capacity may be constructed for its environmental attributes. Princeton Energy Resources International (PERI)—using its Green Power Market Model—provided an estimate of wind capacity additions in response to the expanding green power markets in many places throughout the country. The projections for green power wind installations were incorporated into the OnLocation-modified NEMS (NEMS-GPRA05), and Brookhaven National Laboratory-modified MARKAL (MARKAL-GPRA05) models as planned capacity additions.

Detailed Model Input Information

NEMS-GPRA05 Baseline

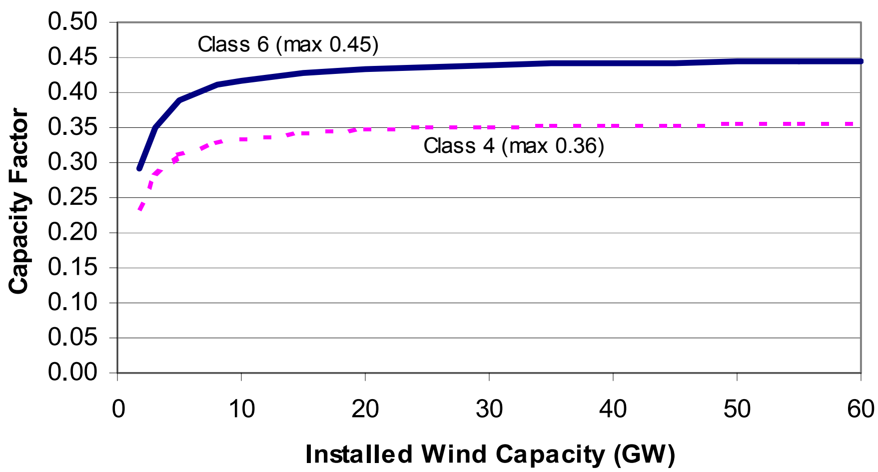
The baseline, which is used to measure the wind program's benefits, is developed using NEMS-GPRA05 and some of the assumptions in the Energy Information Administration's (EIA) *Annual Energy Outlook 2003* (*AEO2003*) Reference Case. In developing the baseline, the only change made to the model regarding wind energy is that certain assumptions about regional cost multipliers are altered, as described below. The *AEO2003* treats wind as a mature technology that experiences, in the future, only a limited amount of cost reduction through learning (only 1% reduction in costs for each doubling of capacity). As a result, the capital costs decline only slightly over time (**Table 1**).

Table 1. *AEO2003* Wind Costs

	Overnight Cost ($2001/kW)	Total Including Contingency ($2001/kW)
2002	938	1004
2005	932	997
2010	929	994
2015	927	992
2020	925	990
2025	924	989

Source: *Assumptions to the AEO2003*, p. 121, Table 73

The capacity factors for the three wind classes in the *AEO2003* are based on a learning function and a specified ultimate capacity factor for each class. The learning-induced improvements in capacity factors used by EIA asymptotically approach the specified capacity factor limits. The resulting factors for Class 4 and Class 6 wind resources, using the *AEO2003* parameters (see **Figure 1**).



Source: *AEO2003*

Figure 1. *AEO2003* Wind Performance

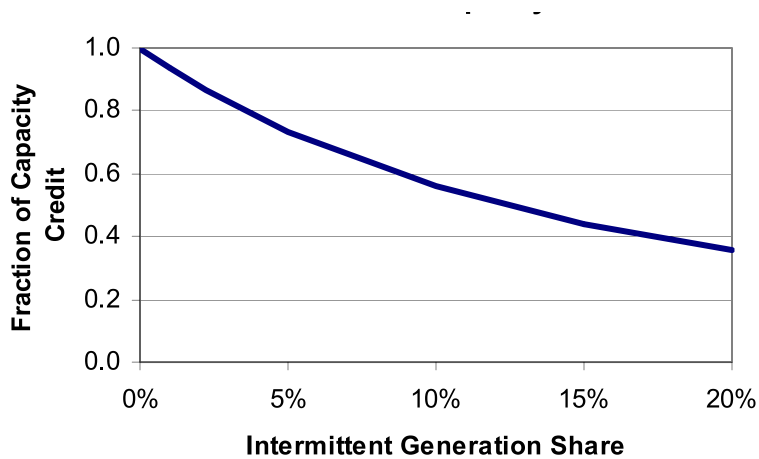
The resulting capacity factors by year are not very different from those of the *AEO2002.* The capacity factors can be specified by year instead of as a function of the learning parameters.

Table 2. *AEO2003* Resulting Wind-Capacity Factors

	Class 6	Class 5	Class 4
2005	0.406	0.370	0.325
2010	0.412	0.376	0.330
2015	0.418	0.381	0.335
2020	0.421	0.383	0.337
2025	0.423	0.385	0.338

Source: *AEO2003*

EIA set the limit on the share of generation in each region that can be met with intermittent technologies at 20% for the *AEO2003*, up from 12% in the *AEO2002*. However, the capacity credit toward meeting peak requirements declines with the increasing share of intermittent generation (wind, CSP, and PV). When the share of intermittent generation is very small, the capacity credit is equal to the capacity factor in the time period when the peak occurs. If the intermittent generation share rises to as high as 20%, the capacity credit would only be 35% of the capacity factor. (**Figure 2**).



Source: *AEO2003*

Figure 2. *AEO2003* Intermittent Capacity Credit

The *AEO2003* uses short-term (national growth) and long-term (regional resource) multipliers (factors to account for various resource and market phenomena that are postulated to increase the cost of deploying technology). In NEMS-GPRA05, the resource multipliers are applied by wind class rather than across the entire wind resource in each region.

Assumptions in Support of NEMS-GPRA05 Benefits Analysis

The NEMS-GPRA05 electricity sector module performs an economic analysis of alternative technologies in each of 13 regions. Within each region, new capacity is selected based on its relative capital and operating costs, its operating performance (i.e., capacity factor, which reflects energy conversion efficiency, and both resource and plant availability), the regional load requirements, and existing capacity resources. Unlike the *AEO2003* version of NEMS, NEMS-GPRA05 characterizes wind by three wind classes, each with its own capital costs and resource cost multipliers. The regional resource cost multipliers increase capital costs as increasing portions of a wind class is developed in a given region to reflect 1) declining natural resource quality, 2) required transmission network upgrades, 3) competition with other market uses, including aesthetic or environmental concerns. As the cost in that region increases, it may be more cost-effective to consider installing wind turbines in areas of lesser wind resource, but with lower ancillary costs and less-costly access to the grid, as reflected in the model by the capital cost multipliers. These multiplier assumptions are viewed as very conservative, and may overestimate the effects of actual market dynamics.

Other key assumptions that can affect projections include a limit on the share of generation in each region that can be met with intermittent technologies. The *AEO2003* assumption that wind may provide only a maximum of 20% of a region's generation was maintained, even though the program disagrees with that characterization. NEMS-GPRA05, as in the *AEO2003*, also assumes that the capacity value of wind diminishes with increasing levels of installed wind capacity in a region. Finally, another constraint on the growth of wind resource development is how quickly the wind industry can expand before costs increase due to manufacturing bottlenecks. The *AEO2003* assumption that a cost premium is imposed when new orders exceed 50% of installed capacity was maintained for the benefits analysis.

The following assumptions (**Table 3**) about capital costs, capacity factors, and O&M costs are used as inputs into the NEMS-GPRA05 model to match the program's performance goals.

Table 3. Capital Costs, Capacity Factors, and O&M Costs for Wind

Wind Technology Assumptions		2005	2010	2015	2020	2025
Class 6 Capital Cost*	2003 $/kW	1,113	910	856	835	829
Class 5 Capital Cost*	2003 $/kW	1,113	910	856	835	829
Class 4 Capital Cost*	2003 $/kW	1,231	1,017	963	936	910
Capacity Factor - Class 6	fraction	0.520	0.495	0.507	0.514	0.517
Capacity Factor - Class 5	fraction	0.462	0.442	0.453	0.457	0.460
Capacity Factor - Class 4	fraction	0.391	0.388	0.452	0.467	0.470
Total O&M Costs	2003 $/kW-year	13.4	8.0	7.6	7.6	7.6

*Includes 1.07 contingency factor.
Source: Wind Energy Program, as reflected in *Wind Energy Program Multi Year Technical Plan, 2004 – 2010 (November 2003),* http://www.nrel.gov/wind_meetings/2003_imp_meeting/pdfs/mytp_nov_2003.pdf

In addition to competing on an economic basis with other electricity generation technologies, wind capacity may be constructed for its environmental benefit. The PERI Green Power Market Model estimated that nearly 4,700 MW of wind would be installed by 2025, in response to the expanding green power markets in many places throughout the country. Analysts included the region-by-region breakout of projections for green power wind installations in NEMS-GPRA05 as planned capacity additions. Because these additions "use up" a part of the overall wind resource base, they may reduce the new construction estimated for the least-cost sector. As a result, the total incremental capacity may not equal the green power plus these additions.

MARKAL-GPRA05

The program goals are represented in the MARKAL-GPRA05 model by changing the capital and O&M costs and capacity factors for wind turbines to match the program goals as represented in **Table 1**.

The discount rate for wind generators is set at 8% (instead of the utility average of 10%) to reflect the accelerated depreciation schedule available for renewable generation technologies. Wind generators are modeled as centralized plants to compete with fossil fuel-based plants. The potential contribution of wind systems to meeting peak power demand is limited to 40%, reflecting the intermittent nature of the technology. As with PV systems, this disadvantages wind generators, as additional reserve capacity is needed to meet peak power requirements. However, this disadvantage is offset by the reduction in capital cost and performance improvements projected for wind technologies by the program. As a result, wind generators near the central grid can be competitive with fossil fuel-based power plants. The green power capacity additions are added as a lower bound in the MARKAL-GPRA05 model.

Green Power

Green power additions (from PERI) were provided by region and are included as planned capacity additions. The Green Power additions were provided to 2035. After 2035, they remain flat as most of the renewable capacity will likely be introduced competitively by then.

Table 4. Wind-Power Assumptions

	2010	2020	2030	2040	2050
Capital Costs with Contingency Factor **(2003 $/kW)**					
Class 6	$910	$835	$803	$781	$760
Class 5	$910	$835	$803	$781	$760
Class 4	$1,017	$936	$899	$877	$856
Fixed O&M Cost **($/kW/year)**	8.0	7.6	7.6	7.6	7.6
Capacity Factor					
Class 6	50%	51%	52%	52%	52%
Class 5	44%	46%	46%	46%	46%
Class 4	39%	47%	47%	47%	47%

Source: Wind Energy Program, as reflected in *Wind Energy Program Multi Year Technical Plan, 2004 – 2010 (November 2003)*, http://www.nrel.gov/wind_meetings/2003_imp_meeting/pdfs/mytp_nov_2003.pdf

Table 5. Incremental Green Power Wind-Capacity Additions (MW)

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2005-2025
ECAR	31	267	299	126	67	791
ERCT	12	139	166	83	42	442
MAAC	59	300	221	16	17	613
MAIN	19	165	185	78	41	488
MAPP	2	38	99	77	35	251
NY	39	200	147	11	12	409
NE	32	185	134	22	21	394
FL	0	0	0	0	0	0
STV	0	0	0	0	0	0
SPP	12	157	229	137	66	601
NWPP	2	35	69	57	33	196
RA	4	33	58	38	26	159
CNV	0	50	108	107	55	319
Total	212	1,569	1,714	751	415	4,661

Hydropower Program Assumptions in Support of Benefits Estimates

The hydropower program benefits, as projected in response to GPRA05 (for the FY2005 budget request), were developed from data provided by the Wind and Hydropower Technologies Program. The program has identified five opportunities for increasing generation (and installed capacity) from U.S. hydropower resources:

1. Building new capacity at untapped or underutilized high-head sites
2. Preserving capacity and generation that might otherwise be lost to relicensing processes
3. Increasing energy production through new operational procedures and increased reservoir efficiency
4. Increasing energy production at existing facilities through the implementation of advanced turbine technology
5. Building capacity at new low-head/low-power sites

For GPRA05, the analysis of the hydropower program's impacts was limited to the first three items. The program plans to perform the necessary analysis during the coming year to estimate the outcomes from the latter two items.

The program's estimates of outcomes, which serve as inputs into NEMS-GPRA05 and MARKAL-GPRA05, are provided in **Table 6**, and their basis is described below.

Table 6. Hydropower Program Estimates of Capacity and Generation (used in NEMS-GPRA05 and MARKAL-GPRA05 Integrated Modeling)

	2010	2015	2020	2025
Impact 1: Capacity Not Lost to Relicensing and Operational Review Processes (GW)	3.4	3.5	3.7	3.8
Impact 2: Generation Not Lost to Relicensing and Operational Review Processes (billion kWh)	13.1	13.5	14.0	14.4
Impact 3: Generation Increase Due to Operational Efficiencies (billion kWh)	3	6	8	9
Total Increase in Generation (billion kWh)	16	19	22	24

Capacity Growth at High-Head Sites

The NEMS-GPRA05 model, used by EERE for GPRA analyses, allows new conventional hydroelectric capacity to be built in addition to reported plans. Drawing from Idaho National Engineering and Environmental Laboratory information on U.S. hydroelectric potential, the

NEMS Electricity Market Module (EMM) contains regional conventional hydroelectric supply estimates at increasing capital costs. All the capacity is assumed available at a uniform capacity factor of 45%, which is a good estimate of the national annual average capacity factor. Data maintained for hydropower include the available capacity, capacity factors, and costs (capital, and fixed and variable operating and maintenance). Because of hydroelectric power's priority position in the merit order of generation, it is assumed that all available installed hydroelectric capacity will be used within the constraints of available water supply and general operating requirements (including environmental regulations).

NEMS-GPRA05 does not estimate pumped storage hydroelectric capacity, which is considered a storage medium for coal and nuclear power and not a renewable energy supply.

NEMS does not project the construction of any new hydropower capacity in the Energy Information Administration's (EIA) *Annual Energy Outlook 2003* (*AEO2003*) cases, due to the high cost of building new sites relative to other generating options.

Capacity Not Lost to Relicensing and Operational Review Processes

The EIA *AEO2003* "Reference Case" currently projects that, in 2005, there will be 78.8 GW installed in the United States. That number increases to 78.92 GW in 2010, and stays level after that. The Hydroelectric Power Data File in the EMM represents reported plans for new conventional hydroelectric power capacity connected to the transmission grid and reported on Form EIA-860, Annual Electric Generator Report, and Form EIA-867, Annual Nonutility Power Producer Report.

Important to note, EIA's projections are level, despite the large quantity of hydropower under review for relicensing. The GPRA hydropower analysts assume that EIA's AEO projections reflect the projected success of R&D efforts sponsored by the Office of Wind and Hydropower Technologies. This success will allow hydro-facility owners/operators to overcome regulatory impetus for plant derating and/or decommissioning.

Because the purpose of the EERE GPRA analysis is to measure the benefit of EERE program activities, the EIA *AEO2003* projections are adjusted, where necessary, to allow for representation of the "program case." The baseline, which is used to measure the program case, therefore, is the level of hydropower that would happen if no DOE-sponsored programs existed. That baseline is used for the GPRA analysis and is summarized in **Table 7**.

The amount of capacity up for relicensing is sizeable. There are currently 2,200 non-Federal projects, representing about 37 GW. This is roughly one-half the total U.S. hydropower capacity. Of the 37 GW, some 15.5 GW are due to be relicensed by the end of 2010. In the following five years, an additional 4.6 GW are due, with 1.0 GW and 2.5 GW in the two five-year increments beyond that. The total due by 2010 is 23.2 GW, or about 30% of total U.S. capacity.

The GPRA hydropower analysis uses the assumption that, by 2010—without DOE efforts—6% of the capacity (and by assumption, an equivalent percentage of generation) of plants up for relicensing during that period would be lost. The 6% estimate of recovered generation is based on an inventory of all plants that will have their licenses renewed during the analysis period. By 2025, program efforts would save 6% of the generation from of an additional 7.8 GW, which is the amount subject to relicensing between 2011 and 2025. Values for intervening years are interpolated.

In addition, the 41 GW of Federal facilities, while not subject to FERC relicensing, are subject to continual review for the same issues. The 6% saving factor, therefore, is assumed to also apply to Federal facilities.

It should be noted that, although assumed to be true for this analysis, a 6% reduction in the 2010 capacity is not necessarily equated to a 6% loss in generation, because relicensing stipulations might require different water-flow management strategies. However, for simplicity, that assumption was made for GPRA05. As a further simplification, the GPRA05 model runs did not attempt to capture regional effects. For GPRA06, the program will attempt to capture regional variations, which, while having little or no effect on the hydropower projections for annual generation, could have some implications for the use of other renewables and conventional fuels.

Improved Operations

An additional effect of the program activities is expected to result from improved operation of reservoirs. Generation can be increased at a given plant by optimizing a number of different aspects of plant operations. These include settings of individual units, multiple-unit operations, and release patterns from multiple reservoirs. This is a new opportunity for the program that responds to requests from industry and environmental interests.

Table 7. Relicensing Data and Assumptions

Total U.S. Hydro Capacity (2004)	78 GW	AEO 2003 Data
Non-Federal U.S. Hydro Capacity (2004)	37 GW	FERC Data
Capacity up for relicensing 2004-2010	15.4 GW	Based on FERC data; ~20% of total U.S. hydro capacity
Capacity up for relicensing 2011-2015	4.6 GW	Based on FERC data
Capacity up for relicensing 2016-2020	1.0 GW	Based on FERC data
Capacity up for relicensing 2021-2025	2.2 GW	Based on FERC data
Capacity up for relicensing 2004-2025	23.2 GW	Based on FERC data
Federal Capacity Under Review	41 GW	All Federal capacity subject to environmental review
Program GPRA Assumption for capacity saved in 2010	6% of capacity up for relicensing and 6% of all Federal capacity, or 3.4 GW	Generation is assumed to be also increased by 6%.
Program GPRA Assumption for capacity saved in 2025	6%, of capacity up for relicensing and 6% of all Federal capacity, or 3.8 GW	Generation is assumed to be also increased by 6%.

FERC Source (November 2003): http://www.ferc.gov/industries/hydropower/gen-info/projlic.PDF

There are significant technical challenges that need to be addressed in this effort, including improved hydraulic measurements. Also, an integrated approach to energy and environment will be applied in this research, ensuring that the multiple objectives of environmental quality and energy production are achieved together. The need to improve the scientific basis for decisions concerning water management at hydropower dams and reservoirs is becoming increasingly acute as competition over limited water resources escalates throughout the United States.

Experience from TVA's hydropower improvement programs has demonstrated that energy production can be increased 30% or more through a combination of equipment upgrades and optimizing operations. Other expert opinions from the hydropower industry estimate average improvements of at least 10%. **Figure 3** shows hydropower operational data from TVA's hydropower system for the period 1956 to 1997, before and after implementation of a series of improvement programs that replaced older equipment with advanced technology, and optimized operations at levels ranging from individual units to series of reservoirs.

For the GPRA05 analysis, the program has chosen as its goal the modest improvement by 2010 of 3 billion kWh (or 1% of total U.S. hydropower generation). It should be noted that the overall program goal for increased generation at existing plants is 10% by 2010, of which operational improvements are 4% component, and the introduction of new turbine technology is another 6%. For GPRA05, the generation increase from operational improvements is assumed to grow to 3% of the U.S. total generation. This value of 3% is still short of the program goal—and, thus, is a conservative understatement of the program impact.

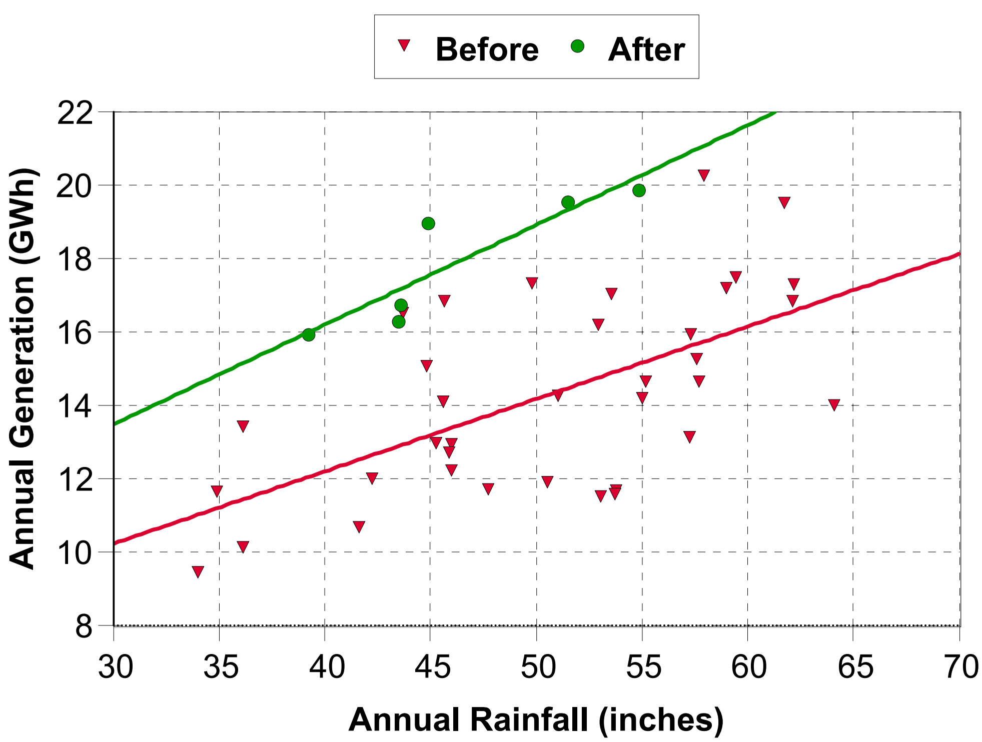


Figure 3. Data from TVA's Hydropower Improvement Program

Appendix M – GPRA05 Estimate of Penetration of Generating Technologies into Green Power Markets

Introduction

The Green Power Market Model (GPMM or the model) identifies and analyzes the potential electric-generating capacity additions that will result from "green power" programs, which are not captured in the "least-cost" analyses performed by the National Energy Modeling System (NEMS). The model projects green power-capacity additions through both green power marketing programs in deregulated markets, and utility green pricing programs in regulated markets.

Princeton Energy Resources International, LLC (PERI) originally constructed the GPMM as a sub-module in the summer of 2000, with the results hardwired into NEMS as planned capacity. This year's model, the FY05 GPMM, is based in Microsoft Excel 97 and is consistent with efforts during the past several years. The model continues to use a detailed and regionalized set of assumptions for electricity market restructuring, coming from a recent National Renewable Energy Laboratory (NREL) report, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*. [1] The assumptions taken from this report include the dates for initiation of market restructuring (except where noted later), as well as the assumed green power-penetration rates. The report included both a high-growth and low-growth case, with varying assumptions for market restructuring, access to green power, and customer participation rates. The GPMM uses the assumptions of the high-growth case, except where noted.

The Green Power Network, a part of the U.S. Department of Energy (DOE), defines both green power and green power marketing on their Web site. It states that the "essence of green power marketing is to provide market-based choices for electricity consumers to purchase power from environmentally preferred sources. The term "green power" is used to define power generated from renewable energy sources, such as wind and solar power, geothermal, hydropower and various forms of biomass." [2]

For purposes of this analysis, the term "green marketing" refers to selling green power in the competitive marketplace, in which multiple suppliers and service offerings exist. "Green" marketing programs occur in restructured markets that were formerly served by either investor-owned utilities (IOU) or public utility companies (PUC) and give the customer the option of paying a market price (higher if necessary) to ensure that their electricity demand is met by green power. [2] "Green pricing" programs, on the other hand, represent the programs sponsored by utilities that give customers the opportunity to pay extra to support the development and operation of green power sources. Those utilities (both IOUs and PUCs), which remain regulated in our analysis, have the option of providing "green pricing" programs.

Electricity markets are now restructured and openly competitive in several states: Arizona, Connecticut, Delaware, the District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Rhode Island, Pennsylvania, Texas, and Virginia. Green power marketing products are currently being offered in nine states, including Maine, New Jersey, New York, Pennsylvania, Illinois, District of Columbia, Maryland, Virginia, and Texas. Green power pricing programs are being offered by utilities in 32 states, including Alabama, Arizona, California, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kentucky, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Mexico, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Dakota, South Carolina, Tennessee, Texas, Utah, Vermont, Washington, Wisconsin, Wyoming. [3 and 4]

The Model

Time frame:

The model projects increased capacity and electricity generated from green technologies for the periods 2005, and then five-year periods to 2035. The FY05 model extended the time frame of analysis to 2035, by giving half of the green revenues and capacity builds from the 2026-2030 period to the 2031-2035 period.

Technologies:

Thirteen individual technologies, comprising five technology types, were selected as both green and commercially viable for this analysis. These are:

1) Biomass:	- Direct-Fired Biomass
	- Biomass Gasification
	- Landfill Gas
2) Geothermal:	- Flash Geothermal
	- Binary Geothermal
	- Hot Dry Rock
3) Concentrated Solar Power:	- Solar Thermal Trough
	- Solar Thermal Dish-Hybrid
	- Solar Central Receiver
4) Photovoltaics:	- Residential PV (Neighborhood)
	- Central Station PV (Thin Film)
	- Concentrator PV
5) Wind:	- Wind Turbines

Although the model was initially designed to distinguish between dispatchable and intermittent technologies, more recent versions of the model exclude this distinction. The original distinction was accomplished by adding an extra cost to intermittent technologies associated with “firming up” the technologies’ ability to provide a constant power supply. However, since green power programs only guarantee that a certain percentage of total kilowatt-hours generated will come from green sources over the course of a year, the developers of new green power do not have the incentive to include backup generation to provide a continuous source of power. Developers are therefore assumed to build the sites in least-cost fashion (i.e., without backup) and take the "green" electrons when and from where they are able.

Regions:
The model is composed of regional segments, used to capture differences in the costs of competing technologies, resource availability, levels of participation in voluntary green marketing programs, and electricity demand by sector. PERI has elected to use U.S. Census regions as the breakdown, as the availability of regional data for the model often takes this format. Eight regions (the South Atlantic and East South Central regions have been combined) are modeled independently, and then summed to produce national results (see **Appendix A**). The regions for this analysis are 1) New England, 2) Middle Atlantic, 3) East North Central, 4) West North Central, 5) South Atlantic and East South Central, 6) West South Central, 7) Mountain, and 8) Pacific. Detailed results of the model are shown by Census Region in **Appendix B**.

This regional breakdown is different from the regional divisions of NEMS, however. In order to be hardwired into NEMS, the eight regional capacity projections must be converted to the 13 divisions used in NEMS. The NEMS divisions are based on the North American Electric Reliability Council's (NERC) regions. The names of these regions, and the conversion formulas from the census region breakdown, are documented in the model. Detailed results of the model are shown by NEMS Region in **Appendix C**.

Assumptions:
The technology cost and performance data was taken from the DOE/EPRI report, *Renewable Energy Technology Characterizations, EPRI-TR109496* (TC). [5] New characterizations for wind (with Class 4 and Class 6 data averaged) and CSP (trough and power tower data) were taken from program revisions to the TC report. All technology cost figures were converted to 2000$, using GPD price deflators from http://w3.access.gpo.gov/usbudget/fy2001/sheets/hist10z1.xls.

The state-by-state restructuring and penetration assumptions are taken from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy.* [1] These rates are summed across the regions, and are prorated based on the loads of the electric market in each state compared to the region as a whole. State-by-state assumptions for restructuring, green power access, and customer participation rates are shown in **Appendix D**.

A number of new assumptions were included in this year's analysis that alter the assumptions given in the NREL report—primarily the start dates for electric market restructuring in states that do not currently have specific plans (see **Appendix D**). In order to more accurately reflect the fairly high degree of uncertainty surrounding electric market restructuring—particularly in light of the unstable markets seen in California that caused electricity choice to be suspended there, as well as the delayed restructuring in Arkansas, Montana, Oklahoma and New Mexico—PERI reviewed the most recent updates to EIA's Status of State Electric Industry Restructuring Activity, which lists updates to state activity as of February 2003. [6] In response to the delays and lack of market restructuring activity, this year's analysis has pushed back the start dates (for states with no pending start date) from the January 1, 2004, start date assumed in prior years to

January 1, 2008. This change has led to greatly decreased capacity builds in the early years of the model, to 2010, in comparison to the results of the FY04 GPMM.

The model also assumes that market rules are conducive to competition and customer switching, and customer understanding and participation continues to increase. Specific assumptions from the high-growth scenario include:

- IOU restructuring: States already open to competition remain open, and retail choice continues as scheduled.
- PUC restructuring: Starts at 2.5% in the third year after IOU restructuring commences, and increases to 20% by the 10^{th} year.
- Access to Green Power: In regulated markets, starts at 5% and increases 60%; while, in competitive markets, 100% is assumed to be open.
- Green Power Market Penetration: In regulated markets, participation starts at 0.75% for residential customers in first year, increasing by 0.75% annually to 7.5% in the 10^{th} year; while, in competitive markets, participation starts at 1% and increases to 15% in the 15^{th} year. Nonresidential customers are a constant 25% of residential participation in both regulated and competitive markets. [1]

As states begin to restructure their markets, it is assumed the pace of restructuring will vary from state to state. But within five years of deregulation, it is assumed that 100% of the IOUs markets will have active retail competition—except as dictated by existing legislation—including green marketing programs. To this extent, all states are assumed to restructure at least a portion of their electric markets by 2008. [1]

On the other hand, green pricing is an optional utility service that allows customers an opportunity to support a greater level of utility company investment in renewable energy technologies. Participating customers pay a premium on their electric bill to cover the extra cost of the renewable energy. Green pricing implies a continued regulated arena in which an optional fee is paid by customers to promote their utility's development of renewable energy technologies. The assumptions of the NREL report incorporated in our model suggest that a portion of those utilities still regulated in each state will offer green pricing programs. As more markets are restructured, the green pricing programs are converted to green marketing programs. However, the customer participation levels achieved under green pricing programs are assumed to remain at a constant level the first year under deregulation, with the incremental gains of deregulated markets starting in the following year. Another important assumption incorporated into our model is that restructuring never fully includes all of the PUCs, nor do green pricing programs ever enter into all of the still-regulated utilities. From these assumptions, it can be seen that at least some of the customers in each state never gain access to green power markets; but the regional percentage of all customers with access to green power programs grows to 63-91% in the out years of the analysis.

A second set of assumptions taken from the NREL report deals with customer participation in green power programs. The assumption used in earlier year's analyses (that 30% of eligible residential customers would eventually enroll in these voluntary programs) was both reduced overall and varied regionally to more accurately reflect customer participation rates in existing programs. The customer participation rates reach 7-13% in the out years of the analysis, a reduction of more than 50% from the original assumption.

Participation rates for the commercial and industrial sectors are tied into the residential participation rates. The NREL report assumes that combined commercial/industrial participation rate is 25% of that of the residential sector. Commercial and industrial customers' participation rates are set at 16.7% and 8.3%, respectively, of their residential customers counterparts. Another key assumption is that all customers continue in the programs, once they have joined. **Table 1** shows the assumptions and calculations of regional customer participation rates for green marketing programs.

Table 1. Regional Participation Rates in Green Power programs

	2000	2005	2010	2015	2020	2025	2030
New England	1.1%	5.1%	9.5%	12.4%	12.6%	12.7%	12.7%
Mid. Atlantic	0.4%	5.0%	9.6%	13.0%	13.0%	13.0%	13.0%
E. N. Central	0.0%	2.3%	5.9%	9.7%	11.0%	11.4%	11.4%
W.N. Central	0.0%	0.0%	0.9%	3.9%	6.3%	7.1%	7.1%
S. Atl. & E.S. Central	0.0%	0.4%	1.9%	5.2%	7.6%	8.3%	8.3%
W.S. Central	0.0%	1.3%	4.1%	7.3%	8.7%	9.0%	9.0%
Mountain	0.0%	1.5%	3.9%	8.0%	10.0%	10.8%	10.8%
Pacific	0.0%	0.0%	1.5%	4.7%	7.7%	8.8%	8.8%

Another important assumption is the choice of how to model the payments for participation in green power programs. A range of payment devices currently exists in programs underway, with some programs charging an additional amount per kilowatt-hour, a fixed amount each month, or a percentage of the total bill. PERI has chosen to use the percentage of the total bill, assumed to be 10%, to more accurately show the regional energy price variation. Originally, the model used a fixed payment-per-month method to represent all programs, with amounts of $6, $96, $408 for the residential, commercial, and industrial sectors, respectively. However, this fixed price method does not reflect the regional energy price variability, nor is it the most commonly used method in current programs. Because the model already incorporated both the average regional electricity use and regional electricity prices, PERI was able to calculate a regionally varied amount of funds generated by green power programs.

The model uses only the dollars from new customers joining green programs each year to build the new capacity, because money from customers who have joined in prior years is assumed to continue to finance projects built in those years. Another key assumption is that all of the money collected from these programs will go toward building additional capacity.

A very important modeling assumption allows the model to build multiple competing technologies in a region, not only the least-cost alternative. This approach avoids so-called knife-edge choices, and recognizes that single-point estimates of data actually represent a range of values. The percentage apportioned to each technology is inversely related to its first-year cost of energy (FY COE) through a sharing algorithm (i.e., a logit function), consistent with NEMS modeling procedures. The spread of the distribution depends on a scaling factor, lambda, which often ranges from 0 to 15. As this factor increases, the lower-cost technologies receive a higher percentage of the total distribution. PERI has chosen to set this factor at 3.2. A small sensitivity analysis was conducted ranging lambda from 2 to 8 with minor impacts (less than 10%) on the resulting totals.

Another set of assumptions deals with creating regional distinctions in the model by varying the resource potential of the technologies. This was done both throughout the entire nation and in subsets of the regions, depending on the specific technology characterizations. Landfill gas, for example, is limited nationwide by the availability of an economically viable resource base. To account for this, a 70 MW capacity limit was instituted in each region. For this year's model, the regional limit on the amount of landfill gas (LFG) was modified so that only one-fifth of the five-year regional limit of 70 MW, or 14 MW, was allowed for the one-year period of 2005.

For other technologies, such as CSP and Geothermal, resource-based regional distinctions were introduced via adjustment factors (AF). For each technology, a base capacity factor (CF) was taken from the TC report. [5] The AFs were then applied to the base CFs in order to create the regional distinctions. An AF greater than one implies that the resource is more prevalent in that region; and, therefore, the cost of producing electricity from that technology would be lower. The AFs are based on available resource levels as determined from resource maps in the TC document. The AFs for each region, and the subsequent regional CFs, are noted in **Appendix E**. Additionally, certain technologies are excluded from regions, due to prohibitively high costs or the absence of a resource base, by setting their respective AFs to zero. **Table 2** documents these exclusions.

Table 2. Regional Exclusion of Green Technologies

Technology	Region 1	Region 2	Region 3	Region 4	Region 5	Region 6	Region 7	Region 8
Direct-Fired Biomass								
Biomass Gasification								
Landfill Gas								
Flash Geothermal	X	X	X	X	X	X		
Binary Geothermal	X	X	X	X	X	X		
Hot Dry Rock	X	X	X	X	X	X		
Solar Thermal Trough								
Solar Thermal Dish Hybrid								
Solar Central Receiver	X	X	X		X			
Residential PV (Neighborhood)								
Central Station PV (Thin Film)								
Concentrator PV								
Wind Turbines					X			

X- indicates regions where technology is assumed to be unavailable.

Geothermal technologies are restricted to penetrate in only the Pacific and Mountain regions. Central Receivers are restricted to regions west of the Mississippi, consistent with NEMS modeling procedures. Despite the fact that the Central Receiver technology is the only type of CSP technology modeled in NEMS, we allow the other CSP technologies (troughs and dishes) to compete more widely in the model. Although dish and trough CSP technologies are competitive in all regions, they are given substantial penalties in regions with lower solar insolation via the AFs. For example, the trough technology has a national average of 33% for its CF; however, due to the reductions introduced by the AFs for the New England and Middle Atlantic regions, the CF in these regions is about 23%. The reduction in CF also has the effect of increasing the COE, making this technology less competitive in these regions.

Annual Energy Outlook Inputs:
The number of customers by economic sector for each region is determined by the number of residential housing units for the residential sector, the amount of commercial floor space for the commercial sector, and the industrial gross output for the industrial sector. This data is taken from the most recent Energy Information Administration's (EIA) assumptions for the *Annual Energy Outlook 2003, DOE/EIA-0383(2003)* (AEO03). [7] The residential housing-units data was updated using data provided by John Cymbalsky of the EIA on July 18, 2003, in the spreadsheet file "AEO 2003 Households- from J Cymbalsky- 7-18-03.xls." The commercial floor space and industrial gross output were updated from the AEO03 supplemental data tables, Tables 22 and 23, respectively. [7] The number of commercial establishments is calculated assuming 13,000 square feet per establishment; and the number of industrial establishments is calculated assuming $10 million of gross output per establishment.

The regional energy consumption and prices were taken from Tables 1-20 of AEO2003 Supplemental Data Tables. [7] **Tables 3-5**, on the following pages, show the differences in regional energy consumption and prices for the residential, commercial, and industrial sectors between the FY04 and the FY05 models.

Table 3. Residential Energy Consumption and Prices by Census Region

Census Region	Model Year	2000 Residential Energy Consumption (Quads)	2020 Residential Energy Consumption (Quads)	2000 Residential Energy Prices (2000¢/kWh)	2020 Residential Energy Prices (2000¢/kWh)
National	FY05	4.07	5.59	8.09	7.58
	FY04	4.07	5.70	8.31	7.70
New England	FY05	0.14	0.16	10.53	10.98
	FY04	0.14	0.19	11.62	10.57
Mid-Atlantic	FY05	0.38	0.45	10.62	9.58
	FY04	0.38	0.49	11.00	9.90
E. N. Central	FY05	0.59	0.83	7.61	6.83
	FY04	0.58	0.83	7.93	7.16
W.N. Central	FY05	0.30	0.42	7.44	6.62
	FY04	0.30	0.41	7.52	6.88
S. Atlantic and E.S. Central	FY05	1.34	1.89	7.67	7.26
	FY04	1.35	1.95	7.95	7.20
W.S. Central	FY05	0.61	0.90	7.71	7.08
	FY04	0.61	0.87	7.46	7.13
Mountain	FY05	0.25	0.39	7.27	7.57
	FY04	0.25	0.39	7.42	7.74
Pacific	FY05	0.46	0.55	8.46	8.70
	FY04	0.46	0.59	8.75	8.70

Table 4. Commercial Energy Consumption and Prices by Census Region

Census Region	Model Year	2000 Commercial Energy Consumption (Quads)	2020 Commercial Energy Consumption (Quads)	2000 Commercial Energy Prices (2000¢/kWh)	2020 Commercial Energy Prices (2000¢/kWh)
National	FY05	3.96	6.20	7.22	6.92
	FY04	3.91	6.12	7.55	6.94
New England	FY05	0.16	0.23	8.96	9.09
	FY04	0.14	0.19	9.74	8.13
Mid-Atlantic	FY05	0.51	0.67	9.32	8.24
	FY04	0.49	0.63	9.64	8.44
E. N. Central	FY05	0.54	0.73	6.51	6.26
	FY04	0.55	0.74	7.06	6.66
W.N. Central	FY05	0.30	0.45	6.16	5.71
	FY04	0.28	0.41	6.18	5.86
S. Atlantic and E.S. Central	FY05	1.13	1.96	6.54	6.57
	FY04	1.11	1.95	6.88	6.51
W.S. Central	FY05	0.48	0.70	6.72	6.30
	FY04	0.49	0.72	6.51	6.32
Mountain	FY05	0.24	0.44	6.12	6.44
	FY04	0.28	0.52	6.41	6.59
Pacific	FY05	0.60	1.02	8.27	7.91
	FY04	0.56	0.95	9.09	7.85

Table 5. Industrial Energy Consumption and Prices by Census Region.

Census Region	Model Year	2000 Industrial Energy Consumption (Quads)	2020 Industrial Energy Consumption (Quads)	2000 Industrial Energy Prices (2000¢/kWh)	2020 Industrial Energy Prices (2000¢/kWh)
National	FY05	3.63	4.63	4.45	4.38
	FY04	3.65	4.83	4.61	4.45
New England	FY05	0.09	0.10	7.22	6.58
	FY04	0.09	0.11	7.73	6.19
Mid-Atlantic	FY05	0.29	0.35	5.69	5.40
	FY04	0.29	0.36	5.82	5.76
E. N. Central	FY05	0.78	0.97	4.19	4.36
	FY04	0.78	1.00	4.48	4.59
W.N. Central	FY05	0.28	0.35	4.11	3.82
	FY04	0.29	0.36	4.22	3.88
S. Atlantic and E.S. Central	FY05	0.99	1.25	4.21	4.19
	FY04	1.00	1.31	4.38	4.25
W.S. Central	FY05	0.55	0.72	4.10	4.30
	FY04	0.56	0.77	3.99	4.29
Mountain	FY05	0.23	0.32	3.79	4.01
	FY04	0.24	0.33	3.91	3.99
Pacific	FY05	0.42	0.57	5.08	4.44
	FY04	0.41	0.59	5.36	4.49

As can be seen from **Tables 3-5**, only minor differences occur in the economic-sector demand assumptions for energy consumption and prices. In the residential sector of **Table 3**, the residential energy consumption for the nation decreased 0.11 Quads by 2020, from 5.70 to 5.59 Quads. This reduced the growth rate of energy consumption for the country as a whole; which, in turn, reduces the average monthly electric bills, the pool of green money, and the total capacity built to meet green power market demand. **Table 4** shows the commercial-sector demand assumptions. The most noted change is the change in New England's commercial-sector energy prices, which decreased from 9.74 ¢/kWh to 8.13 ¢/kWh in the FY04 model, but actually increases from 8.96 ¢/kWh to 9.09 ¢/kWh in the FY05 model. **Table 5** shows the industrial-sector demand assumptions, which remained the most consistent of the sectors in regard to energy consumption and prices from FY04 to FY05.

Other Inputs:
PERI included both additions and subtractions to the green capacity values for the Million Solar Roofs (MSR) capacity additions, and EIA "Floors" builds, **Tables 6-8**.

A primary means of deployment for PV is expected to be in distributed systems, which are customer-sited and customer-owned. This market for distributed systems will be easier for PV to compete in, because it allows PV to compete with retail electricity prices, not the very low competitive grid prices. The MSR initiative targets this application. The realization of MSR goals for PV—600,000 systems installed by 2010—has formed the basis for the distributed power-penetration projections since the FY01 GPRA benefits reporting. Projections beyond 2010 assume declining annual growth rates, as would be expected to occur after the end of a major initiative. The current MSR capacity additions, taken from revisions to the FY04 GPRA benefits analysis for the Solar Energy Program and shown in **Table 6**, are added to the green model numbers in the reporting of the Residential PV capacity builds. These estimates have been revised downward to reflect the phasing-out of the program. In the FY04 model, however, the incremental MSR capacity additions were allowed to remain constant once the annual growth rate was reduced to 0. In the FY05 model, the incremental additions were reduced by 10% of the 2015 number for each year from 2015-2024 to arrive at 0 in 2024.

Table 6. Million Solar Roofs – Incremental Capacity Additions in the GPMM05 and GPMM04

Year Period	FY05 MSR Capacity Additions (above 2004 Baseline)	FY04 MSR Capacity Additions (above 2004 Baseline)
2005	70	189
2006-2010	773	711
2011-2015	1,761	1,761
2016-2020	1,348	1,926
2021-2025	385	1,926
2026-2030	0	1,926
2031-2035	0	N/A
Total for 2004-2035	4,337	8,439

EIA describes the inclusion of "Floors" capacity in the Renewable Fuels Module section of the *Assumptions to the Annual Energy Outlook 2003*, page 129, and in the *NEMS Renewable Fuels Module Documentation Report*, page 67. [8 and 9] An additional 332.5 MW of central station PV and 75.5 MW of central station solar thermal capacity are "assumed by EIA to be installed for reasons in addition to least-cost electricity supply," "such as for market testing or unique economic requirements," during the period 2001 to 2025. **Table 7** shows the "Floors" capacity additions, which are prorated for 2004 to 2025 and regionally divided among the regions that have capacity additions in these technologies.

Table 7. EIA "Floors" Incremental Capacity Additions for PV and Solar Thermal in NEMS

Year Period	EIA PV "Floors" Capacity Additions (above 2004 Baseline)	EIA Solar Thermal "Floors" Capacity Additions (above 2004 Baseline)
2005	13.3	3.0
2006-2010	66.5	15.1
2011-2015	66.5	15.1
2016-2020	66.5	15.1
2021-2025	66.5	15.1
2026-2030	0.0	0.0
Total for 2004-2030	279	63.4

These amounts are then subtracted from the green power builds for each region. However, if the prorated regional portion of the "Floors" additions was greater than the regional builds in the GPMM, only the amount predicted to be built by the GPMM was subtracted (i.e., value reported as zero, no negative numbers reported), as shown in **Table 8**. As can be seen in **Table 8**, not all of the PV or Solar Thermal "Floors" additions in **Table 7** were subtracted from the FY05 GPMM model results. This because less capacity is being built in some of the regions by the model than was added by the "Floors" capacity.

Table 8. EIA "Floors" Incremental Capacity Additions Subtracted from the GPMM04

Year Period	EIA PV "Floors" Capacity Additions Subtracted from GPMM04 (above 2004 Baseline)	EIA Solar Thermal "Floors" Capacity Additions Subtracted from GPMM04 (above 2004 Baseline)
2005	0.0	1.7
2006-2010	44.5	15.0
2011-2015	66.5	15.1
2016-2020	65.0	15.1
2021-2025	65.4	15.1
2026-2030	0.0	0.0
Total for 2004-2030	241.4	62.0

Results

Comparison of Final Results

Table 9 shows the final results of the FY05 and FY04 GPMM that were hardwired into the NEMS, detailed results of the FY05 model are given in **Appendix A**. As can be seen in **Table 9**, the total additions have been reduced significantly, especially in the early and late stages of the model (e.g., reduction of 31% of capacity builds by 2010 and 26% of capacity builds by 2030), while the middle years of the analysis remain relatively constant. The cause of the early time frame capacity losses is the revision of state restructuring start dates from 2004 to 2008. With a number of states not entering electricity restructuring until 2008, a significant portion of the early capacity builds from the FY04 model are lost in this year's model. On the other hand, the cause of the late time frame capacity losses is the revision of the PV capacity due to the MSR program, which have been revised significantly downward in the out years of the model. This revision is detailed in **Table 6**.

Table 9. Comparison of Results of the FY05 and FY04 GPMM Model (MW of added capacity)

	2010		2020		2030	
	FY05	**FY04**	**FY05**	**FY04**	**FY05**	**FY04**
Biomass (incl. LFG)	150	287	558	673	706	802
Geothermal	91	209	485	600	628	705
CSP	137	257	738	801	994	970
PV	866	968	4,343	4,973	4,942	9,045
Wind	1,781	2,632	4,246	4,601	4,907	4,948
Total	3,025	4,353	10,371	11,648	12,176	16,470

Sensitivity Analysis:

Additionally, PERI performed a sensitivity analysis (i.e., a reality check), to gauge the ability of the model to predict what has happened in the real world. A recent NREL report states that 982 MW of new renewables have been built to meet green power marketing and green pricing programs' demand since the end of 2002. [10]

When the FY05 model is run for the time frame of 1999-2002, the cumulative capacity built by the model by 2002 is 621 MW (i.e., 710 MW with the MSR additions and "Floors" subtracted). This analysis shows that the model is performing reasonably well; and, if anything, is thus far conservative in its projections. Additionally, the model predicts wind technologies to receive about 92% of total builds in the initial results of the GPMM, which is consistent with the NREL estimate of wind capacity serving green power programs, at 93%. [10]

Table 10. Comparison of Capacity Additions to Meet Green Power Programs (MW)

Renewable Technologies	NREL-2003 Report*	FY05 GPMM for time period 1999-2002			
		Initial Model Results	MSR added	Floors subtracted	Final Results
Biomass (incl. LFG)	45	31			31
Geothermal	10	7			7
CSP	5	10		3.3	7
PV		0	92	0	92
Wind	913	573			573
Total	982	621			710

*The NREL report total contains 8.5 MW of small hydro, which is not modeled in the GPMM, and 4.8 MW of "solar" capacity.

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Appendix A: National Results of the GPMM

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OUTPUT SUMMARY - SUM OF REGIONS

Cumulative Capacity Additions from 2003 Baseline (MW)

	2005	2010	2015	2020	2025	2030	2035
Biomass (incl. LFG)	18	150	377	558	654	706	732
Geothermal	4	91	295	485	585	628	649
CSP	3	138	470	738	890	994	1,046
PV	70	866	2,789	4,343	4,834	4,942	4,996
Wind	212	1,781	3,495	4,246	4,661	4,907	5,030
Total	307	3,026	7,427	10,371	11,624	12,176	12,453

* Includes MSR additions for PV Residential and EIA "Floors" subtractions for PV Central Station and CSP Troughs

GREEN REVENUES ($millions/period)

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
Residential	28	119	384	247	124	61	31
Commercial	5	20	66	49	30	19	10
Industrial	2	6	19	13	8	5	3
Total ($millions/year)	34	145	469	309	162	86	43

CAPACITY- PV FROM MSR PROGRAM- ADDED TO PV-RESIDENTIAL TOTALS

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2005-2035
PV - residential (MW)- incremental	70	773	1,761	1,348	385	0	0	4,337
PV - residential- Generation (MWh)- from Incremental adds	125,706	1,388,153	3,162,404	2,420,738	691,383	0	0	7,788,385
Cumulative - PV adds	70	843	2,604	3,952	4,337	4,337	4,337	

EIA FLOORS CAPACITY- ALREADY INSTALLED BY EIA IN NEMS

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2005-2035
PV Central Station (MW)- incremental	13.3	66.5	66.5	66.5	66.5	0.0	0.0	279
Solar Thermal - Central Station (Trough) (MW)- incremental	3.0	15.1	15.1	15.1	15.1	0.0	0.0	63.4
PV Central Station (MW)- cumulative	13.30	79.80	146.30	212.80	279.30	279.30	279.30	558.60
Solar Thermal - Central Station (Trough) (MW)- cumulative	3.0	18.1	33.2	48.3	63.4	63.4	63.4	126.8

EIA FLOORS CAPACITY- Amount Subtracted from GPMM

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2005-2035
PV Central Station (MW)	0.0	44.5	66.5	65.0	65.4	0.0	0.0	241.4
Solar Thermal - Central Station (Trough) (MW)	1.4	15.1	15.1	15.1	15.1	0.0	0.0	61.8
PV Central Station- Generation (MWh)	0	80,667	120,586	117,850	118,561	0	0	437,664
Solar Thermal - CS (Trough)- Generation (MWh)	5,076	67,725	67,725	67,725	67,725	0	0	277,134
Cumulative PV- subtractions	0.0	44.5	111.0	176.0	241.4	241.4	241.4	
Cumulative CSP- subtractions	1.4	16.5	31.6	46.7	61.8	61.8	61.8	

CAPACITY TO BE CONSTRUCTED FROM GREEN MONEY

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Cumulative Specific Tech. Totals	Cumulative RET Totals
Firm, Dispatchable Power (MW)									
Direct-Fired Biomass	3	24	61	52	21	7	3	**172**	**Total Biomass**
Biomass Gasification	5	45	95	67	31	13	6	**263**	**732**
Landfill Gas	11	62	70	62	43	33	16	**297**	
Flash Geotherma	3	62	146	137	72	30	15	**465**	**Total Geothermal**
Binary Geothermal	1	25	58	53	28	12	6	**182**	**649**
Hot Dry Rock	0	0	0	0	1	1	0	**1**	
Solar Thermal Trough	1	36	115	96	56	42	21	**368**	**Total Solar Thermal**
Slr Thermal Dish Hybrid	0	68	143	100	45	18	9	**384**	**1,046**
Solar Central Receiver	2	30	74	72	50	43	22	**294**	
As-Delivered, Intermittent Power (MW)									
Solar Cntrl Receiver	0	0	0	0	0	0	0	**0**	
Slr Thermal Dish Alone	0	0	0	0	0	0	0	**0**	
Residential PV (Neighborhood)	70	773	1,761	1,363	401	21	10	**4,399**	**Total PV**
Central Station PV (Thin Film)	0	7	84	87	28	53	26	**285**	**4,996**
Concentrator PV	0	16	78	103	62	34	17	**311**	
Wind - Class 5- dropped	0	0	0	0	0	0	0	**0**	**Total Wind**
Wind - Class 4 and Class 6 Avg	212	1,569	1,714	751	415	246	123	**5,030**	**5,030**
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TOTAL (MW)	307	2,719	4,401	2,945	1,253	553	276	**12,453**	**12,453**

ELECTRICITY GENERATED FROM CONSTRUCTED CAPACITY

	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Cumulative Specific Tech. Totals	Cumulative RET Totals
Firm, Dispatchable Power (MWh)									
Direct-Fired Biomass	18,686	169,583	430,619	367,733	145,620	47,246	23,623	**1,203,110**	**Total Biomass**
Biomass Gasification	32,472	314,998	669,083	471,346	220,348	90,396	45,198	**1,843,843**	**5,392,181**
Landfill Gas	85,751	491,748	551,880	489,225	338,210	258,943	129,471	**2,345,228**	
Flash Geothermal	22,544	517,599	1,224,716	1,150,690	602,427	254,319	127,160	**3,899,455**	**Total Geothermal**
Binary Geothermal	9,705	207,908	482,462	443,676	234,069	99,622	49,811	**1,527,254**	**5,437,707**
Hot Dry Rock	0	0	0	0	4,633	4,244	2,122	**10,998**	
Solar Thermal Trough	1,049	110,891	381,196	318,966	180,050	149,464	74,732	**1,216,348**	**Total Solar Thermal**
Slr Thermal Dish Hybrid	1,685	301,103	632,951	443,533	200,553	80,747	40,374	**1,700,946**	**5,155,409**
Solar Central Receiver	8,121	203,584	543,251	563,248	397,675	348,158	174,079	**2,238,115**	
As-Delivered, Intermittent Power (MWh)									
Solar Cntrl Receiver	0	0	0	0	0	0	0	**0**	
Slr Thermal Dish Alone	0	0	0	0	0	0	0	**0**	
Residential PV (Neighborhood)	125,706	1,388,153	3,162,404	2,448,425	720,428	38,192	19,096	**7,902,404**	**Total PV**
Central Station PV (Thin Film)	0	13,572	157,291	163,679	54,093	97,913	48,957	**535,506**	**9,105,946**
Concentrator PV	0	35,455	165,866	221,163	133,480	74,714	37,357	**668,036**	
Wind - Class 5- dropped	0	0	0	0	0	0	0	**0**	**Total Wind**
Wind - Class 4 and Class 6 Avg	779,933	6,611,254	7,313,892	3,322,100	1,802,473	1,051,804	525,902	**21,407,358**	**21,407,358**
	---------	---------	---------	---------	---------	---------	---------	---------	**Total RETs**
TOTAL (MW)	#######	10,365,849	15,715,613	10,403,784	5,034,060	2,595,762	1,297,881	**46,498,601**	**46,498,601**

Appendix B: Results by Census Region (MW)

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Direct Fired Biomass	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.3	1.2	1.2	0.3	0.2	0.2	0.1	3.41
Mid. Atlantic	0.8	3.2	3.4	0.3	0.3	0.3	0.1	8.40
E. N. Central	0.45	2.85	4.55	2.58	1.14	0.61	0.3	12.47
W.N. Central	0.00	0.27	1.35	1.53	0.57	0.14	0.1	3.93
S. Atl. & E.S. Central	0.85	14.51	45.81	43.20	16.56	5.12	2.6	128.60
W.S. Central	0.20	1.78	3.02	2.07	0.85	0.45	0.2	8.60
Mountain	0.05	0.00	0.82	0.73	0.41	0.00	0.0	2.02
Pacific	0.00	0.42	1.32	1.75	0.74	0.00	0.0	4.24
Total US	2.67	24.20	61.45	52.47	20.78	6.74	3.37	171.68

Biomass Gasification	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.5	2.2	1.9	0.4	0.3	0.3	0.2	5.66
Mid. Atlantic	1.5	5.8	5.2	0.4	0.4	0.5	0.2	14.10
E. N. Central	0.77	5.22	7.07	3.31	1.73	1.09	0.5	19.73
W.N. Central	0.00	0.50	2.09	1.96	0.87	0.25	0.1	5.79
S. Atl. & E.S. Central	1.48	26.58	71.18	55.37	25.06	9.21	4.6	193.48
W.S. Central	0.36	3.25	4.70	2.66	1.28	0.82	0.4	13.47
Mountain	0.09	0.61	1.28	0.94	0.62	0.39	0.2	4.12
Pacific	0.00	0.78	2.05	2.25	1.12	0.38	0.2	6.77
Total US	4.63	44.95	95.47	67.26	31.44	12.90	6.45	263.11

Landfill Gas	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.4	2.2	2.2	1.3	1.0	0.8	0.4	8.34
Mid. Atlantic	1.2	6.1	6.1	1.5	1.4	1.2	0.6	18.07
E. N. Central	2.05	10.26	10.26	10.26	5.29	2.81	1.4	42.32
W.N. Central	0.00	2.56	5.23	5.23	2.65	0.64	0.3	16.63
S. Atl. & E.S. Central	4.67	23.33	23.33	23.33	23.33	23.33	11.7	133.00
W.S. Central	2.01	10.88	10.88	9.62	3.92	2.10	1.1	40.46
Mountain	0.48	3.09	4.57	3.40	1.91	1.00	0.5	14.96
Pacific	0.00	3.95	7.41	7.41	3.44	0.99	0.5	23.70
Total US	10.88	62.37	70.00	62.05	42.90	32.84	16.42	297.47

Flash Geothermal	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	2.77	27.29	56.27	40.36	25.56	15.19	7.6	175.04
Pacific	0.00	34.91	90.13	96.47	46.08	15.05	7.5	290.14
Total US	2.77	62.20	146.40	136.83	71.64	30.24	15.12	465.19

Binary Geothermal	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	1.19	10.96	22.17	15.56	9.93	5.95	3.0	68.74
Pacific	0.00	14.02	35.50	37.19	17.90	5.89	2.9	113.46
Total US	1.19	24.98	57.67	52.76	27.83	11.85	5.92	182.21

Hot Dry Rock	2003-2007	2008-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	0.00	0.00	0.00	0.00	0.00	0.29	0.1	0.43
Pacific	0.00	0.00	0.00	0.00	0.62	0.28	0.1	1.05
Total US	0.00	0.00	0.00	0.00	0.62	0.57	0.28	1.48

Solar Thermal Trough	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.1	1.6	1.7	0.2	0.3	0.7	0.3	4.99
Mid. Atlantic	0.5	4.7	4.9	0.0	0.3	1.1	0.6	12.07
E. N. Central	0.15	4.11	7.04	3.58	2.28	2.85	1.4	21.43
W.N. Central	0.00	0.29	3.04	3.48	1.92	0.96	0.5	10.18
S. Atl. & E.S. Central	0.00	18.67	81.35	75.34	42.21	27.86	13.9	259.36
W.S. Central	0.06	5.37	9.99	6.37	3.71	4.59	2.3	32.38
Mountain	0.00	1.02	3.33	2.88	2.54	2.76	1.4	13.91
Pacific	0.00	0.65	3.15	4.33	2.77	1.63	0.8	13.34
Total US	0.81	36.44	114.51	96.22	55.99	42.47	21.23	367.67

* Includes Subtractions of NEMS "Floor" Capacity Additions

Solar Thermal Dish Hybrid	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	2.4	2.1	0.4	0.3	0.3	0.1	5.68
Mid. Atlantic	0.0	6.9	6.0	0.5	0.5	0.5	0.2	14.61
E. N. Central	0.00	6.59	8.75	4.01	2.00	1.21	0.6	23.16
W.N. Central	0.00	0.95	3.87	3.55	1.50	0.41	0.2	10.49
S. Atl. & E.S. Central	0.25	38.71	101.61	77.30	33.53	11.78	5.9	269.07
W.S. Central	0.11	8.87	12.55	6.95	3.20	1.95	1.0	34.63
Mountain	0.00	2.09	4.33	3.11	1.98	1.18	0.6	13.28
Pacific	0.00	1.58	4.08	4.37	2.10	0.69	0.3	13.15
Total US	0.37	68.13	143.32	100.15	45.13	17.99	8.99	384.07

Appendix B: Results by Census Region (MW) (cont.)

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Solar Central Receiver	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	2.12	11.61	14.21	8.64	4.23	2.1	42.93
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	1.33	19.81	37.66	27.85	18.43	20.03	10.0	135.12
Mountain	0.41	4.68	12.98	12.47	11.37	12.08	6.0	60.02
Pacific	0.00	3.52	12.23	17.53	12.05	7.04	3.5	55.89
Total US	1.73	30.12	74.48	72.05	50.50	43.38	21.69	293.95

Solar Central Receiver- Intermittent	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Pacific	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Total US	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Solar Thermal Dish- Alone	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Pacific	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Total US	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PV Residential	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.5	5.4	12.3	9.5	2.7	0.4	0.2	30.96
Mid. Atlantic	0.8	8.6	19.6	15.0	4.3	0.6	0.3	49.15
E. N. Central	1.93	21.32	48.57	37.18	10.62	1.44	0.7	121.77
W.N. Central	0.61	6.76	15.40	11.79	3.37	0.46	0.2	38.61
S. Atl. & E.S. Central	60.13	664.01	1,512.70	1,173.33	345.43	14.64	7.3	3,777.56
W.S. Central	4.51	49.79	113.43	86.83	26.03	2.13	1.1	283.77
Mountain	1.55	17.10	38.95	29.82	8.52	1.15	0.6	97.66
Pacific	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Total US	70.00	773.00	1,761.00	1,363.39	400.94	20.76	10.38	4,399.47

* Includes Additions of MSR Capacity Additions

Central Station PV	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	1.1	1.4	0.0	0.0	0.9	0.4	3.81
Mid. Atlantic	0.0	3.4	4.4	0.0	0.0	1.4	0.7	9.93
E. N. Central	0.00	1.35	5.39	2.32	0.40	3.51	1.8	14.72
W.N. Central	0.00	0.00	1.96	3.15	1.08	1.11	0.6	7.86
S. Atl. & E.S. Central	0.00	0.00	60.97	71.70	22.39	35.80	17.9	208.76
W.S. Central	0.00	1.04	6.74	4.35	0.82	5.20	2.6	20.74
Mountain	0.00	0.00	1.70	1.83	1.32	2.82	1.4	9.08
Pacific	0.00	0.00	1.84	4.01	1.88	1.87	0.9	10.54
Total US	0.00	6.87	84.39	87.36	27.90	52.62	26.31	285.44

* Includes Subtractions of NEMS "Floor" Capacity Additions

Concentrator PV	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	1.2	0.4	0.5	0.6	0.3	2.83
Mid. Atlantic	0.0	0.0	3.4	0.5	0.7	0.9	0.5	5.88
E. N. Central	0.00	0.00	4.89	4.13	2.75	2.31	1.2	15.23
W.N. Central	0.00	0.00	2.14	3.61	2.04	0.78	0.4	8.97
S. Atl. & E.S. Central	0.00	13.33	56.82	79.69	46.15	22.55	11.3	229.82
W.S. Central	0.00	3.04	6.98	7.12	4.38	3.72	1.9	27.10
Mountain	0.00	0.00	2.40	3.17	2.69	2.23	1.1	11.61
Pacific	0.00	0.00	0.00	4.51	2.89	1.32	0.7	9.37
Total US	0.00	16.37	77.74	103.11	62.02	34.38	17.19	310.81

Wind - Class 5- dropped	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
Mid. Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
E. N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.N. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Mountain	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Pacific	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
Total US	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Wind - Class 4 and Class 6 Avg	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	Total 2002-2030
New England	31.9	185.1	133.6	22.2	20.8	20.1	10.0	423.72
Mid. Atlantic	98.5	499.4	368.4	26.8	29.1	30.7	15.4	1,068.23
E. N. Central	51.94	445.63	498.81	209.55	112.11	72.63	36.3	1,426.98
W.N. Central	0.00	42.89	147.53	123.96	56.27	16.61	8.3	395.57
S. Atl. & E.S. Central	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00
W.S. Central	23.88	277.97	331.38	166.95	83.12	54.44	27.2	964.96
Mountain	5.76	51.80	90.21	59.44	40.47	25.93	13.0	286.57
Pacific	0.00	66.25	144.49	142.07	72.95	25.67	12.8	464.27
Total US	211.98	1,569.04	1,714.41	750.96	414.84	246.04	123.02	5,030.31

Appendix C: Capacity Installed by NEMS region (MW)

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Direct Fired Biomass	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.4	3.2	7.3	5.9	2.3	0.9	0.4
2	0.1	0.9	1.5	1.0	0.4	0.2	0.1
3	0.6	3.4	6.6	4.5	1.8	0.7	0.3
4	0.2	1.1	1.7	1.0	0.4	0.2	0.1
5	0.0	0.2	0.9	0.9	0.4	0.1	0.0
6	0.3	1.3	1.3	0.1	0.1	0.1	0.1
7	0.3	1.2	1.2	0.3	0.2	0.2	0.1
8	0.2	2.9	9.2	8.6	3.3	1.0	0.5
9	0.5	8.7	27.5	25.9	9.9	3.1	1.5
10	0.1	1.0	2.1	1.7	0.7	0.3	0.1
11	0.0	0.1	0.6	0.7	0.3	0.0	0.0
12	0.0	0.0	0.5	0.5	0.3	0.0	0.0
13	0.0	0.3	1.0	1.3	0.6	0.0	0.0
Total	2.7	24.2	61.4	52.5	20.8	6.7	3.37

Biomass Gasification	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.6	5.8	11.4	7.5	3.5	1.6	0.8
2	0.2	1.6	2.3	1.3	0.6	0.4	0.2
3	1.0	6.2	10.3	5.8	2.8	1.2	0.6
4	0.3	1.9	2.6	1.2	0.6	0.4	0.2
5	0.0	0.4	1.4	1.2	0.5	0.2	0.1
6	0.6	2.3	2.1	0.2	0.2	0.2	0.1
7	0.5	2.2	1.9	0.4	0.3	0.3	0.2
8	0.3	5.3	14.2	11.1	5.0	1.8	0.9
9	0.9	15.9	42.7	33.2	15.0	5.5	2.8
10	0.2	1.8	3.2	2.2	1.0	0.5	0.3
11	0.0	0.4	1.0	0.9	0.5	0.2	0.1
12	0.1	0.4	0.8	0.6	0.4	0.2	0.1
13	0.0	0.6	1.5	1.7	0.8	0.3	0.1
Total	4.6	44.9	95.5	67.3	31.4	12.9	6.45

Landfill Gas	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	1.7	8.5	8.5	8.5	5.5	4.0	2.0
2	1.0	5.4	5.4	4.8	2.0	1.1	0.5
3	1.2	6.0	6.0	3.3	3.2	3.0	1.5
4	0.8	3.8	3.8	3.8	2.0	1.0	0.5
5	0.1	1.8	3.3	3.3	1.7	0.5	0.2
6	0.5	2.4	2.4	0.6	0.5	0.5	0.2
7	0.4	2.2	2.2	1.3	1.0	0.8	0.4
8	0.9	4.7	4.7	4.7	4.7	4.7	2.3
9	2.8	14.0	14.0	14.0	14.0	14.0	7.0
10	1.0	6.5	7.7	7.1	3.1	1.3	0.7
11	0.2	2.1	3.5	3.1	1.5	0.6	0.3
12	0.3	2.0	2.9	2.2	1.2	0.6	0.3
13	0.0	3.0	5.6	5.6	2.6	0.7	0.4
Total	10.9	62.4	70.0	62.1	42.9	32.8	16.42

Binary Geothermal	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.4	7.5	16.9	14.9	8.1	3.6	1.8
12	0.8	7.0	14.2	10.0	6.4	3.8	1.9
13	0.0	10.5	26.6	27.9	13.4	4.4	2.2
Total	1.2	25.0	57.7	52.8	27.8	11.8	5.92

Flash Geothermal	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	1.0	18.6	42.8	38.6	20.7	9.2	4.6
12	1.8	17.5	36.0	25.8	16.4	9.7	4.9
13	0.0	26.2	67.6	72.3	34.6	11.3	5.6
Total	2.8	62.2	146.4	136.8	71.6	30.2	15.12

Appendix C: Capacity Installed by NEMS region (MW) - cont.

Hot Dry Rock	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.2	0.2	0.1
12	0.0	0.0	0.0	0.0	0.0	0.2	0.1
13	0.0	0.0	0.0	0.0	0.5	0.2	0.1
Total	0.0	0.0	0.0	0.0	0.6	0.6	0.28

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Solar Thermal Dish- Hybrid	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	7.8	15.4	10.1	4.6	1.9	1.0
2	0.1	4.4	6.3	3.5	1.6	1.0	0.5
3	0.0	8.0	13.8	8.0	3.6	1.5	0.7
4	0.0	2.4	3.2	1.5	0.7	0.4	0.2
5	0.0	0.7	2.5	2.1	0.9	0.3	0.1
6	0.0	2.8	2.4	0.2	0.2	0.2	0.1
7	0.0	2.4	2.1	0.4	0.3	0.3	0.1
8	0.1	7.7	20.3	15.5	6.7	2.4	1.2
9	0.2	23.2	61.0	46.4	20.1	7.1	3.5
10	0.1	4.8	7.9	5.0	2.2	1.2	0.6
11	0.0	1.1	2.6	2.2	1.2	0.6	0.3
12	0.0	1.3	2.8	2.0	1.3	0.8	0.4
13	0.0	1.2	3.1	3.3	1.6	0.5	0.3
Total	0.4	68.1	143.3	100.2	45.1	18.0	8.99

Solar Thermal Dish Alone	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.00

Solar Central Receiver- Firm	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.7	9.9	18.8	13.9	9.2	10.0	5.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	1.2	6.6	8.1	4.9	2.4	1.2
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.7	10.8	23.8	20.0	12.9	11.8	5.9
11	0.1	2.6	7.7	8.9	7.1	6.1	3.1
12	0.3	3.0	8.3	8.0	7.3	7.7	3.9
13	0.0	2.6	9.2	13.1	9.0	5.3	2.6
Total	1.7	30.1	74.5	72.1	50.5	43.4	21.69

Solar Central Receiver- Intermittent	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.00

Appendix C: Capacity Installed by NEMS region (MW) - cont.

Solar Thermal Trough	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.1	4.3	12.4	9.7	5.6	4.5	2.2
2	0.0	2.7	5.0	3.2	1.9	2.3	1.1
3	0.3	4.7	11.1	7.5	4.4	3.5	1.7
4	0.1	1.5	2.6	1.3	0.8	1.1	0.5
5	0.0	0.3	1.9	2.1	1.2	0.6	0.3
6	0.2	1.9	2.0	0.0	0.1	0.4	0.2
7	0.1	1.6	1.7	0.2	0.3	0.7	0.3
8	0.0	3.7	16.3	15.1	8.4	5.6	2.8
9	0.0	11.2	48.8	45.2	25.3	16.7	8.4
10	0.0	2.8	6.3	4.7	2.7	2.7	1.4
11	0.0	0.5	2.0	2.1	1.6	1.4	0.7
12	0.0	0.7	2.1	1.8	1.6	1.8	0.9
13	0.0	0.5	2.4	3.2	2.1	1.2	0.6
Total	0.8	36.4	114.5	96.2	56.0	42.5	21.23

* Includes Subtractions of NEMS "Floor" Capacity Additions

PV Residential	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	7.2	79.2	180.4	139.6	40.9	2.3	1.2
2	2.3	24.9	56.7	43.4	13.0	1.1	0.5
3	6.5	71.6	163.0	126.3	37.1	1.8	0.9
4	0.7	7.9	18.0	13.8	3.9	0.5	0.3
5	0.4	4.5	10.2	7.8	2.2	0.3	0.2
6	0.3	3.4	7.8	6.0	1.7	0.2	0.1
7	0.5	5.4	12.3	9.5	2.7	0.4	0.2
8	12.0	132.8	302.5	234.7	69.1	2.9	1.5
9	36.1	398.4	907.6	704.0	207.3	8.8	4.4
10	2.5	27.8	63.3	48.5	14.5	1.3	0.6
11	0.6	6.2	14.0	10.7	3.1	0.4	0.2
12	1.0	10.9	24.9	19.1	5.5	0.7	0.4
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	70.0	773.0	1,761.0	1,363.4	400.9	20.8	10.38

* Includes Additions of MSR Capacity Additions

Central Station PV	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.8	9.3	8.6	2.5	5.7	2.8
2	0.0	0.5	3.4	2.2	0.4	2.6	1.3
3	0.0	2.0	8.7	7.2	2.2	4.4	2.2
4	0.0	0.5	2.0	0.9	0.1	1.3	0.6
5	0.0	0.0	1.3	1.9	0.6	0.7	0.4
6	0.0	1.4	1.8	0.0	0.0	0.6	0.3
7	0.0	1.1	1.4	0.0	0.0	0.9	0.4
8	0.0	0.0	12.2	14.3	4.5	7.2	3.6
9	0.0	0.0	36.6	43.0	13.4	21.5	10.7
10	0.0	0.5	4.2	3.5	0.9	3.1	1.5
11	0.0	0.0	1.1	1.7	0.9	1.5	0.7
12	0.0	0.0	1.1	1.2	0.8	1.8	0.9
13	0.0	0.0	1.4	3.0	1.4	1.4	0.7
Total	0.0	6.9	84.4	87.4	27.9	52.6	26.31

08/11/03

* Includes Subtractions of NEMS "Floor" Capacity Additions

Concentrator PV	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	1.3	8.6	10.4	6.3	3.6	1.8
2	0.0	1.5	3.5	3.6	2.2	1.9	0.9
3	0.0	1.3	7.7	8.3	5.0	2.8	1.4
4	0.0	0.0	1.8	1.5	1.0	0.9	0.4
5	0.0	0.0	1.4	2.2	1.2	0.5	0.3
6	0.0	0.0	1.3	0.2	0.3	0.4	0.2
7	0.0	0.0	1.2	0.4	0.5	0.6	0.3
8	0.0	2.7	11.4	15.9	9.2	4.5	2.3
9	0.0	8.0	34.1	47.8	27.7	13.5	6.8
10	0.0	1.5	4.4	5.1	3.1	2.2	1.1
11	0.0	0.0	0.9	2.3	1.7	1.1	0.6
12	0.0	0.0	1.5	2.0	1.7	1.4	0.7
13	0.0	0.0	0.0	3.4	2.2	1.0	0.5
Total	0.0	16.4	77.7	103.1	62.0	34.4	17.19

Appendix C: Capacity Installed by NEMS region (MW) - cont.

Wind - Class 5- dropped	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.00

Wind - Class 4 and Class 6 Avg	2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035
1	31.2	267.4	299.3	125.7	67.3	43.6	21.8
2	11.9	139.0	165.7	83.5	41.6	27.2	13.6
3	59.1	299.7	221.0	16.1	17.5	18.4	9.2
4	19.2	164.9	184.6	77.5	41.5	26.9	13.4
5	1.6	37.8	99.1	76.9	35.4	11.6	5.8
6	39.4	199.8	147.3	10.7	11.6	12.3	6.1
7	31.9	185.1	133.6	22.2	20.8	20.1	10.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	11.9	157.4	229.1	136.8	65.8	34.4	17.2
11	2.1	35.2	68.6	56.9	32.8	15.8	7.9
12	3.7	33.1	57.7	38.0	25.9	16.6	8.3
13	0.0	49.7	108.4	106.6	54.7	19.3	9.6
Total	212.0	1,569.0	1,714.4	751.0	414.8	246.0	123.02

Appendix D: Green Power Market Assumptions

From: Swezey, Blair, R. Wiser, M. Bolinger, and E. Holt. 2001. Growing the Green Power Market: forecasting the Impacts of Customer Demand for Renewable Energy. National Renewable Energy Laboratory, US Department of Energy. NREL/TP-620-30101 LBNL-48611)

Table 1- Pace of Restructuring- IOU's

Pace of Restructuring in IOU's

- assumes all states already open to deregulation remain open

- high growth assumes- states not already deregulated will continue on schedule

-Fast States (50% to 100% in 2 yrs) and Slow States (20% to 100% in 5yrs)

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**67%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**33%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Fast	74,792	78%	**58%**	**0%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**

Appendix D: Green Power Market Assumptions (cont.)

Table 2- Pace of Restructuring- Public

Pace of Restructuring in Public

- All States assumed at 2.5% (in 3rd yr after IOU opens) increasing to 20% in 10th yr

Current Conditions

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	0.0%	**10.0%**	20.0%	20.0%	20.0%	20.0%	20.0%
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**0.0%**	**10.0%**	20.0%	20.0%	20.0%	20.0%	20.0%
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	2.5%	**15.0%**	20.0%	20.0%	20.0%	20.0%	**20.0%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	2.5%	**15.0%**	20.0%	20.0%	20.0%	20.0%	**20.0%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**0.0%**	**10.0%**	20.0%	20.0%	20.0%	20.0%	20.0%
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**0.0%**	**12.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0.0%**	**5.0%**	17.5%	20.0%	20.0%	20.0%	20.0%
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0.0%**	**5.0%**	17.5%	20.0%	20.0%	20.0%	20.0%
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**0.0%**	**10.0%**	20.0%	20.0%	20.0%	20.0%	20.0%
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0.0%**	**0.0%**	12.5%	20.0%	20.0%	20.0%	20.0%
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0.0%**	**0.0%**	7.5%	20.0%	20.0%	20.0%	20.0%
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0.0%**	**5.0%**	17.5%	20.0%	20.0%	20.0%	20.0%
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0.0%**	**7.5%**	20.0%	20.0%	20.0%	20.0%	20.0%
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0.0%**	**0.0%**	12.5%	20.0%	20.0%	20.0%	20.0%
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0.0%**	**0.0%**	2.5%	15.0%	20.0%	20.0%	20.0%
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0.0%**	**0.0%**	2.5%	15.0%	**20.0%**	**20.0%**	**20.0%**

Appendix D: Green Power Market Assumptions (cont.)

Table 3- Percentage of Market Deregulated (Competitive % of all market)

							Percentage of Market Deregulated (Competitive % of all market) **-calcuated as (% restructured IOU * IOU %) + (% restructured public * (1- IOU%))**						
							Current Conditions						
Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	**96%**	**96%**	**97%**	**97%**	**97%**	**97%**	**97%**
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**96%**	**96%**	**97%**	**97%**	**97%**	**97%**	**97%**
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	**86%**	**88%**	**88%**	**88%**	**88%**	**88%**	**88%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0%**	**89%**	**90%**	**90%**	**90%**	**90%**	**90%**
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0%**	**0%**	**79%**	**82%**	**83%**	**83%**	**83%**
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0%**	**85%**	**87%**	**87%**	**87%**	**87%**	**87%**
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**63%**	**96%**	**96%**	**96%**	**96%**	**96%**	**96%**
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0%**	**89%**	**90%**	**91%**	**91%**	**91%**	**91%**
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0%**	**0%**	**73%**	**77%**	**78%**	**78%**	**78%**
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0%**	**90%**	**91%**	**91%**	**91%**	**91%**	**91%**
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0%**	**87%**	**89%**	**89%**	**89%**	**89%**	**89%**
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0%**	**0%**	**81%**	**83%**	**84%**	**84%**	**84%**
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0%**	**0%**	**40%**	**71%**	**72%**	**72%**	**72%**
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0%**	**0%**	**44%**	**77%**	**78%**	**78%**	**78%**
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0%**	**0%**	**32%**	**58%**	**61%**	**61%**	**61%**
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0%**	**0%**	**39%**	**69%**	**70%**	**70%**	**70%**
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0%**	**0%**	**3%**	**15%**	**20%**	**20%**	**20%**
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0%**	**0%**	**31%**	**57%**	**60%**	**60%**	**60%**
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0%**	**0%**	**28%**	**52%**	**55%**	**55%**	**55%**
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0%**	**73%**	**77%**	**77%**	**77%**	**77%**	**77%**
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0%**	**0%**	**47%**	**80%**	**82%**	**82%**	**82%**
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0%**	**0%**	**32%**	**58%**	**61%**	**61%**	**61%**
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**30%**	**91%**	**92%**	**92%**	**92%**	**92%**	**92%**
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0%**	**0%**	**41%**	**72%**	**74%**	**74%**	**74%**
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0%**	**0%**	**35%**	**64%**	**66%**	**66%**	**66%**
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0%**	**83%**	**85%**	**86%**	**86%**	**86%**	**86%**
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0%**	**0%**	**59%**	**99%**	**99%**	**99%**	**99%**
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0%**	**0%**	**36%**	**64%**	**66%**	**66%**	**66%**
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0%**	**0%**	**33%**	**61%**	**63%**	**63%**	**63%**
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0%**	**0%**	**27%**	**52%**	**54%**	**54%**	**54%**
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0%**	**0%**	**4%**	**17%**	**21%**	**21%**	**21%**
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0%**	**0%**	**61%**	**66%**	**66%**	**66%**	**66%**
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0%**	**0%**	**46%**	**79%**	**81%**	**81%**	**81%**
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0%**	**0%**	**41%**	**72%**	**74%**	**74%**	**74%**
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0%**	**73%**	**77%**	**78%**	**78%**	**78%**	**78%**
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0%**	**94%**	**95%**	**95%**	**95%**	**95%**	**95%**
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0%**	**0%**	**35%**	**64%**	**66%**	**66%**	**66%**
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0%**	**0%**	**50%**	**85%**	**86%**	**86%**	**86%**
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0%**	**63%**	**68%**	**71%**	**71%**	**71%**	**71%**
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0%**	**0%**	**56%**	**95%**	**95%**	**95%**	**95%**
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0%**	**0%**	**75%**	**78%**	**79%**	**79%**	**79%**
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0%**	**0%**	**46%**	**79%**	**80%**	**80%**	**80%**
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0%**	**0%**	**36%**	**64%**	**66%**	**66%**	**66%**
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	**0%**	**0%**	**78%**	**81%**	**82%**	**82%**	**82%**
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0%**	**0%**	**43%**	**75%**	**77%**	**77%**	**77%**
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0%**	**0%**	**26%**	**50%**	**53%**	**53%**	**53%**
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0%**	**0%**	**8%**	**23%**	**27%**	**27%**	**27%**
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**

Table 4- Regional Percentage of Market Deregulated (Competitive % of all market)

							Regional Percentage of Market Deregulated (Competitive % of all market) **-calcuated as (% restructured IOU * IOU %) + (% restructured public * (1- IOU%))**						
							Current Conditions						
Census Region/State	Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
New England				38,769	90%	100%	**79%**	**87%**	**92%**	**92%**	**92%**	**92%**	**92%**
Middle Atlantic				104,788	91%	100%	**47%**	**92%**	**93%**	**93%**	**93%**	**93%**	**93%**
East North Central				160,431	84%	100%	**0%**	**63%**	**86%**	**87%**	**87%**	**87%**	**87%**
West North Central				84,066	55%	100%	**0%**	**0%**	**34%**	**62%**	**64%**	**64%**	**64%**
South Atlantic				274,833	72%	100%	**2%**	**19%**	**52%**	**77%**	**78%**	**78%**	**78%**
East South Central				100,817	35%	100%	**0%**	**0%**	**23%**	**45%**	**48%**	**48%**	**48%**
S.Atl + ES Central				375,650	62%	100%	**2%**	**14%**	**44%**	**68%**	**70%**	**70%**	**70%**
West South Central				170,993	71%	100%	**0%**	**47%**	**67%**	**76%**	**77%**	**77%**	**77%**
Mountain				64,980	80%	100%	**0%**	**35%**	**65%**	**83%**	**84%**	**84%**	**84%**
Pacific				128,059	67%	100%	**0%**	**0%**	**59%**	**72%**	**74%**	**74%**	**74%**

Appendix D: Green Power Market Assumptions (cont.)

Table 5- Access to Green Power - Competitive Markets

Access to Green Power- Competitive %

- calculated as (% of IOU open*% of power that is IOU) +(% of public deregualted*% of power that is public) * 100% of open has access to GP

-assumes 100% constant in all open markets

Current Conditions

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	**96%**	**96%**	**97%**	**97%**	**97%**	**97%**	**97%**
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**96%**	**96%**	**97%**	**97%**	**97%**	**97%**	**97%**
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	**86%**	**88%**	**88%**	**88%**	**88%**	**88%**	**88%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0%**	**89%**	**90%**	**90%**	**90%**	**90%**	**90%**
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0%**	**0%**	**79%**	**82%**	**83%**	**83%**	**83%**
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0%**	**85%**	**87%**	**87%**	**87%**	**87%**	**87%**
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**63%**	**96%**	**96%**	**96%**	**96%**	**96%**	**96%**
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0%**	**89%**	**90%**	**91%**	**91%**	**91%**	**91%**
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0%**	**0%**	**73%**	**77%**	**78%**	**78%**	**78%**
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0%**	**90%**	**91%**	**91%**	**91%**	**91%**	**91%**
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0%**	**87%**	**89%**	**89%**	**89%**	**89%**	**89%**
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0%**	**0%**	**81%**	**83%**	**84%**	**84%**	**84%**
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0%**	**0%**	**40%**	**71%**	**72%**	**72%**	**72%**
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0%**	**0%**	**44%**	**77%**	**78%**	**78%**	**78%**
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0%**	**0%**	**32%**	**58%**	**61%**	**61%**	**61%**
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0%**	**0%**	**39%**	**69%**	**70%**	**70%**	**70%**
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0%**	**0%**	**3%**	**15%**	**20%**	**20%**	**20%**
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0%**	**0%**	**31%**	**57%**	**60%**	**60%**	**60%**
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0%**	**0%**	**28%**	**52%**	**55%**	**55%**	**55%**
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0%**	**73%**	**77%**	**77%**	**77%**	**77%**	**77%**
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0%**	**0%**	**47%**	**80%**	**82%**	**82%**	**82%**
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0%**	**0%**	**32%**	**58%**	**61%**	**61%**	**61%**
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**30%**	**91%**	**92%**	**92%**	**92%**	**92%**	**92%**
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0%**	**0%**	**41%**	**72%**	**74%**	**74%**	**74%**
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0%**	**0%**	**35%**	**64%**	**66%**	**66%**	**66%**
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0%**	**83%**	**85%**	**86%**	**86%**	**86%**	**86%**
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0%**	**0%**	**59%**	**99%**	**99%**	**99%**	**99%**
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0%**	**0%**	**36%**	**64%**	**66%**	**66%**	**66%**
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0%**	**0%**	**33%**	**61%**	**63%**	**63%**	**63%**
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0%**	**0%**	**27%**	**52%**	**54%**	**54%**	**54%**
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0%**	**0%**	**4%**	**17%**	**21%**	**21%**	**21%**
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0%**	**0%**	**61%**	**66%**	**66%**	**66%**	**66%**
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0%**	**0%**	**46%**	**79%**	**81%**	**81%**	**81%**
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0%**	**0%**	**41%**	**72%**	**74%**	**74%**	**74%**
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0%**	**73%**	**77%**	**78%**	**78%**	**78%**	**78%**
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0%**	**94%**	**95%**	**95%**	**95%**	**95%**	**95%**
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0%**	**0%**	**35%**	**64%**	**66%**	**66%**	**66%**
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0%**	**0%**	**50%**	**85%**	**86%**	**86%**	**86%**
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0%**	**63%**	**68%**	**71%**	**71%**	**71%**	**71%**
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0%**	**0%**	**56%**	**95%**	**95%**	**95%**	**95%**
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0%**	**0%**	**75%**	**78%**	**79%**	**79%**	**79%**
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0%**	**0%**	**46%**	**79%**	**80%**	**80%**	**80%**
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0%**	**0%**	**36%**	**64%**	**66%**	**66%**	**66%**
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	**0%**	**0%**	**78%**	**81%**	**82%**	**82%**	**82%**
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0%**	**0%**	**43%**	**75%**	**77%**	**77%**	**77%**
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0%**	**0%**	**26%**	**50%**	**53%**	**53%**	**53%**
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0%**	**0%**	**8%**	**23%**	**27%**	**27%**	**27%**
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0%**	**0%**	**60%**	**100%**	**100%**	**100%**	**100%**

Table 6- Access to Green Power - Regional Competitive

Access to Green Power- Regional Competitive

Current Conditions

Census Region/State	Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	**79%**	**87%**	**92%**	**92%**	**92%**	**92%**	**92%**
Middle Atlantic				104,788	91%	100%	**47%**	**92%**	**93%**	**93%**	**93%**	**93%**	**93%**
East North Central				160,431	84%	100%	**0%**	**63%**	**86%**	**87%**	**87%**	**87%**	**87%**
West North Central				84,066	55%	100%	**0%**	**0%**	**34%**	**62%**	**64%**	**64%**	**64%**
South Atlantic				274,833	72%	100%	**2%**	**19%**	**52%**	**77%**	**78%**	**78%**	**78%**
East South Central				100,817	35%	100%	**0%**	**0%**	**23%**	**45%**	**48%**	**48%**	**48%**
S.Atl + ES Central				375,650	62%	100%	**2%**	**14%**	**44%**	**68%**	**70%**	**70%**	**70%**
West South Central				170,993	71%	100%	**0%**	**47%**	**67%**	**76%**	**77%**	**77%**	**77%**
Mountain				64,980	80%	100%	**0%**	**35%**	**65%**	**83%**	**84%**	**84%**	**84%**
Pacific				128,059	67%	100%	**0%**	**0%**	**59%**	**72%**	**74%**	**74%**	**74%**

Appendix D: Green Power Market Assumptions (cont.)

Table 7- Access to Green Power - Regulated Markets

Access to Green Power- Regulated (as a % of All customers)

- calculated as (1-% market deregulated) * % of regulated with access to GP

-% of regulated with access to GP is increasing from 10% (2001) to 55% (2010) over ten years for both IOU and Public customers

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	**0%**	**1%**	**2%**	**2%**	**2%**	**2%**	**2%**
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**0%**	**1%**	**2%**	**2%**	**2%**	**2%**	**2%**
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	**0%**	**4%**	**6%**	**6%**	**6%**	**6%**	**6%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0%**	**3%**	**5%**	**5%**	**5%**	**5%**	**5%**
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0%**	**30%**	**12%**	**10%**	**10%**	**10%**	**10%**
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**0%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0%**	**4%**	**7%**	**7%**	**7%**	**7%**	**7%**
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**0%**	**1%**	**2%**	**2%**	**2%**	**2%**	**2%**
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0%**	**3%**	**5%**	**5%**	**5%**	**5%**	**5%**
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0%**	**30%**	**15%**	**13%**	**12%**	**12%**	**12%**
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0%**	**3%**	**5%**	**5%**	**5%**	**5%**	**5%**
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0%**	**4%**	**6%**	**6%**	**6%**	**6%**	**6%**
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0%**	**30%**	**11%**	**9%**	**9%**	**9%**	**9%**
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0%**	**30%**	**33%**	**16%**	**15%**	**15%**	**15%**
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0%**	**30%**	**31%**	**13%**	**12%**	**12%**	**12%**
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0%**	**30%**	**38%**	**23%**	**22%**	**22%**	**22%**
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0%**	**30%**	**34%**	**17%**	**16%**	**16%**	**16%**
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0%**	**30%**	**54%**	**47%**	**44%**	**44%**	**44%**
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0%**	**30%**	**38%**	**23%**	**22%**	**22%**	**22%**
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0%**	**30%**	**40%**	**26%**	**25%**	**25%**	**25%**
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0%**	**8%**	**13%**	**13%**	**13%**	**13%**	**13%**
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0%**	**30%**	**29%**	**11%**	**10%**	**10%**	**10%**
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0%**	**30%**	**38%**	**23%**	**22%**	**22%**	**22%**
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**0%**	**3%**	**4%**	**4%**	**4%**	**4%**	**4%**
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0%**	**30%**	**32%**	**15%**	**14%**	**14%**	**14%**
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0%**	**30%**	**36%**	**20%**	**19%**	**19%**	**19%**
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0%**	**5%**	**8%**	**7%**	**7%**	**7%**	**7%**
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0%**	**30%**	**22%**	**0%**	**0%**	**0%**	**0%**
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0%**	**30%**	**35%**	**20%**	**19%**	**19%**	**19%**
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0%**	**30%**	**37%**	**22%**	**20%**	**20%**	**20%**
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0%**	**30%**	**40%**	**27%**	**25%**	**25%**	**25%**
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0%**	**30%**	**53%**	**46%**	**43%**	**43%**	**43%**
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0%**	**30%**	**22%**	**19%**	**19%**	**19%**	**19%**
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0%**	**30%**	**30%**	**11%**	**11%**	**11%**	**11%**
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0%**	**30%**	**32%**	**15%**	**14%**	**14%**	**14%**
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0%**	**8%**	**13%**	**12%**	**12%**	**12%**	**12%**
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0%**	**2%**	**3%**	**3%**	**3%**	**3%**	**3%**
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0%**	**30%**	**36%**	**20%**	**19%**	**19%**	**19%**
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0%**	**30%**	**28%**	**8%**	**8%**	**8%**	**8%**
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0%**	**11%**	**18%**	**16%**	**16%**	**16%**	**16%**
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0%**	**30%**	**24%**	**3%**	**3%**	**3%**	**3%**
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0%**	**30%**	**14%**	**12%**	**11%**	**11%**	**11%**
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0%**	**30%**	**30%**	**11%**	**11%**	**11%**	**11%**
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0%**	**30%**	**35%**	**20%**	**18%**	**18%**	**18%**
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	**0%**	**30%**	**12%**	**10%**	**10%**	**10%**	**10%**
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0%**	**30%**	**31%**	**14%**	**13%**	**13%**	**13%**
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0%**	**30%**	**41%**	**27%**	**26%**	**26%**	**26%**
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0%**	**30%**	**51%**	**42%**	**40%**	**40%**	**40%**
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0%**	**30%**	**22%**	**0%**	**0%**	**0%**	**0%**

Table 8- Regional Access to Green Power - Regulated

Regional Access to Green Power- Regulated

Census Region/State	Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	**0%**	**3.8%**	**4.5%**	**4.4%**	**4.4%**	**4.4%**	**4.4%**
Middle Atlantic				104,788	91%	100%	**0%**	**2.4%**	**3.8%**	**3.8%**	**3.8%**	**3.8%**	**3.8%**
East North Central				160,431	84%	100%	**0%**	**11.2%**	**7.8%**	**7.2%**	**7.0%**	**7.0%**	**7.0%**
West North Central				84,066	55%	100%	**0%**	**30.0%**	**36.3%**	**21.2%**	**19.9%**	**19.9%**	**19.9%**
South Atlantic				274,833	72%	100%	**0%**	**24.2%**	**26.3%**	**12.8%**	**12.1%**	**12.1%**	**12.1%**
East South Central				100,817	35%	100%	**0%**	**30.0%**	**42.6%**	**30.5%**	**28.7%**	**28.7%**	**28.7%**
S.Atl + ES Central				375,650	62%	100%	**0%**	**25.7%**	**30.6%**	**17.5%**	**16.6%**	**16.6%**	**16.6%**
West South Central				170,993	71%	100%	**0%**	**15.8%**	**18.3%**	**13.0%**	**12.8%**	**12.8%**	**12.8%**
Mountain				64,980	80%	100%	**0%**	**19.5%**	**19.3%**	**9.5%**	**9.0%**	**9.0%**	**9.0%**
Pacific				128,059	67%	100%	**0%**	**30.0%**	**22.3%**	**15.2%**	**14.3%**	**14.3%**	**14.3%**

Appendix D: Green Power Market Assumptions (cont.)

Table 9- Access to Green Power - Total

Access to Green Power- Total (Regulated + Competitive)

= (table 5 * table 3 +(table 7)) : (access to GP in comp * % of market comp) + (access to GP in reg * % of market still reg)

% of All customers with opportunity to buy Green Power

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales* *EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	**92%**	**94%**	**95%**	**95%**	**95%**	**95%**	**95%**
Maine	3/1/2000	Year_01		3,589	96%	**9%**	**92%**	**94%**	**96%**	**96%**	**96%**	**96%**	**96%**
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	**74%**	**80%**	**84%**	**84%**	**84%**	**84%**	**84%**
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	**0%**	**82%**	**87%**	**87%**	**87%**	**87%**	**87%**
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	**98%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	**0%**	**30%**	**74%**	**77%**	**78%**	**78%**	**78%**
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	**96%**	**97%**	**98%**	**98%**	**98%**	**98%**	**98%**
New York	7/1/2001	Year_00		40,240	84%	**38%**	**0%**	**77%**	**83%**	**83%**	**83%**	**83%**	**83%**
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	**40%**	**93%**	**94%**	**94%**	**94%**	**94%**	**94%**
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	**0%**	**82%**	**87%**	**87%**	**87%**	**87%**	**87%**
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	**0%**	**30%**	**68%**	**72%**	**73%**	**73%**	**73%**
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	**0%**	**84%**	**88%**	**88%**	**88%**	**88%**	**88%**
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	**0%**	**79%**	**85%**	**85%**	**85%**	**85%**	**85%**
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	**0%**	**30%**	**76%**	**78%**	**79%**	**79%**	**79%**
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	**0%**	**30%**	**49%**	**66%**	**67%**	**67%**	**67%**
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	**0%**	**30%**	**50%**	**72%**	**73%**	**73%**	**73%**
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	**0%**	**30%**	**48%**	**57%**	**58%**	**58%**	**58%**
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	**0%**	**30%**	**49%**	**64%**	**66%**	**66%**	**66%**
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	**0%**	**30%**	**54%**	**49%**	**48%**	**48%**	**48%**
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	**0%**	**30%**	**48%**	**56%**	**58%**	**58%**	**58%**
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	**0%**	**30%**	**47%**	**54%**	**55%**	**55%**	**55%**
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	**0%**	**61%**	**72%**	**72%**	**72%**	**72%**	**72%**
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	**0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	**0%**	**30%**	**51%**	**76%**	**77%**	**77%**	**77%**
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	**0%**	**30%**	**48%**	**57%**	**58%**	**58%**	**58%**
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	**9%**	**86%**	**89%**	**89%**	**89%**	**89%**	**89%**
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	**0%**	**30%**	**49%**	**67%**	**69%**	**69%**	**69%**
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	**0%**	**30%**	**48%**	**61%**	**62%**	**62%**	**62%**
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	**0%**	**74%**	**81%**	**82%**	**82%**	**82%**	**82%**
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	**0%**	**30%**	**58%**	**99%**	**99%**	**99%**	**99%**
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	**0%**	**30%**	**48%**	**61%**	**62%**	**62%**	**62%**
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	**0%**	**30%**	**48%**	**58%**	**60%**	**60%**	**60%**
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	**0%**	**30%**	**47%**	**53%**	**55%**	**55%**	**55%**
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	**0%**	**30%**	**53%**	**49%**	**48%**	**48%**	**48%**
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	**0%**	**30%**	**59%**	**62%**	**62%**	**62%**	**62%**
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	**0%**	**30%**	**51%**	**74%**	**76%**	**76%**	**76%**
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	**0%**	**30%**	**49%**	**68%**	**69%**	**69%**	**69%**
Texas	1/1/2002	Year_00		110,434	72%	**65%**	**0%**	**62%**	**72%**	**73%**	**73%**	**73%**	**73%**
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	**0%**	**90%**	**93%**	**93%**	**93%**	**93%**	**93%**
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	**0%**	**30%**	**48%**	**61%**	**62%**	**62%**	**62%**
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	**0%**	**30%**	**52%**	**81%**	**82%**	**82%**	**82%**
Montana	7/1/2004	Year_00		3,722	63%	**6%**	**0%**	**51%**	**64%**	**66%**	**66%**	**66%**	**66%**
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	**0%**	**30%**	**56%**	**92%**	**93%**	**93%**	**93%**
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	**0%**	**30%**	**70%**	**73%**	**74%**	**74%**	**74%**
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	**0%**	**30%**	**51%**	**74%**	**75%**	**75%**	**75%**
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	**0%**	**30%**	**48%**	**61%**	**63%**	**63%**	**63%**
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	**0%**	**30%**	**73%**	**76%**	**77%**	**77%**	**77%**
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	**0%**	**30%**	**50%**	**70%**	**72%**	**72%**	**72%**
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	**0%**	**30%**	**47%**	**53%**	**54%**	**54%**	**54%**
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	**0%**	**30%**	**51%**	**48%**	**47%**	**47%**	**47%**
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	**0%**	**30%**	**58%**	**100%**	**100%**	**100%**	**100%**

Table 10- Access to Green Power - All customers

Regional Access to Green Power- Total (Regulated + Competitive)

% of all customers that are eligible for access to GP

Census Region/State	Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales* *EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	**72%**	**84%**	**89%**	**89%**	**89%**	**89%**	**89%**
Middle Atlantic				104,788	91%	100%	**37%**	**88%**	**91%**	**91%**	**91%**	**91%**	**91%**
East North Central				160,431	84%	100%	**0%**	**67%**	**82%**	**83%**	**83%**	**83%**	**83%**
West North Central				84,066	55%	100%	**0%**	**30%**	**49%**	**62%**	**63%**	**63%**	**63%**
South Atlantic				274,833	72%	100%	**1%**	**41%**	**58%**	**73%**	**74%**	**74%**	**74%**
East South Central				100,817	35%	100%	**0%**	**30%**	**50%**	**55%**	**56%**	**56%**	**56%**
S.Atl + ES Central				375,650	62%	100%	**1%**	**38%**	**56%**	**68%**	**69%**	**69%**	**69%**
West South Central				170,993	71%	100%	**0%**	**51%**	**65%**	**71%**	**72%**	**72%**	**72%**
Mountain				64,980	80%	100%	**0%**	**51%**	**67%**	**80%**	**80%**	**80%**	**80%**
Pacific				128,059	67%	100%	**0%**	**30%**	**63%**	**70%**	**71%**	**71%**	**71%**

Appendix D: Green Power Market Assumptions (cont.)

Table 11- Green Power Penetration as % of eligible Competitive customers

Green Power Penetration as % of Eligible Competitive Customers
- assumes 1% to 15% (over 15 yrs) increase for competitive customers
- assume non-residential is a constant 25% of residential demand

Current Conditions

Census Region/State	FY05 Case-Specific Direct Access Date	Model Year in 2000	Fast vs. Slow For states with no Firm date	Residential Total Sales EIA Table 14 (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%							
Connecticut	7/1/2000	Year_01		10,935	96%	28%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Maine	3/1/2000	Year_01		3,589	96%	9%	1.0%	6.0%	11.0%	15.0%	15.0%	15.0%	15.0%
Massachusetts	3/1/1998	Year_03		16,388	85%	42%	3.0%	8.0%	13.0%	15.0%	15.0%	15.0%	15.0%
New_Hampshire	5/1/2001	Year_00		3,384	88%	9%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Rhode Island	1/1/1998	Year_03		2,522	99%	7%	3.0%	8.0%	13.0%	15.0%	15.0%	15.0%	15.0%
Vermont	1/1/2008	Year_00	Fast	1,951	78%	5%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Middle Atlantic				104,788	91%	100%							
New Jersey	#######	Year_01		23,191	98%	22%	1.0%	6.0%	11.0%	15.0%	15.0%	15.0%	15.0%
New York	7/1/2001	Year_00		40,240	84%	38%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Pennsylvania	1/1/1999	Year_02		41,358	95%	39%	2.0%	7.0%	12.0%	15.0%	15.0%	15.0%	15.0%
East North Central				160,431	84%	100%							
Illinois	5/1/2002	Year_00		39,685	88%	25%	0.0%	4.0%	9.0%	14.0%	15.0%	15.0%	15.0%
Indiana	1/1/2008	Year_00	Fast	27,334	73%	17%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Michigan	1/1/2002	Year_00		29,808	89%	19%	0.0%	4.0%	9.0%	14.0%	15.0%	15.0%	15.0%
Ohio	1/1/2001	Year_00		44,516	86%	28%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	12%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
West North Central				84,066	55%	100%							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	14%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Kansas	1/1/2008	Year_00	Slow	11,832	73%	14%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	21%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Missouri	1/1/2008	Year_00	Slow	28,265	63%	34%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	10%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	4%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	4%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
South Atlantic				274,833	72%	100%							
Delaware	4/1/2001	Year_00		3,339	71%	1%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
District of Columbia	1/1/2001	Year_00		1,596	100%	1%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Florida	1/1/2008	Year_00	Slow	95,768	77%	35%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Georgia	1/1/2008	Year_00	Slow	41,519	51%	15%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Maryland	7/1/2000	Year_01		22,407	90%	8%	1.0%	6.0%	11.0%	15.0%	15.0%	15.0%	15.0%
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	16%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	9%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Virginia	1/1/2004	Year_00		34,703	83%	13%	0.0%	2.0%	7.0%	12.0%	15.0%	15.0%	15.0%
West Virginia	1/1/2008	Year_00		9,053	99%	3%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
East South Central				100,817	35%	100%							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	27%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	21%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	16%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	35%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
West South Central				170,993	71%	100%							
Arkansas	#######	Year_00		14,339	58%	8%	0.0%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	16%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	11%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Texas	1/1/2002	Year_00		110,434	72%	65%	0.0%	4.0%	9.0%	14.0%	15.0%	15.0%	15.0%
Mountain				64,980	80%	100%							
Arizona	1/1/2001	Year_00		21,611	94%	33%	0.0%	5.0%	10.0%	15.0%	15.0%	15.0%	15.0%
Colorado	1/1/2008	Year_00	Slow	12,652	57%	19%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Idaho	1/1/2008	Year_00	Slow	6,610	82%	10%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Montana	7/1/2004	Year_00		3,722	63%	6%	0.0%	2.0%	7.0%	12.0%	15.0%	15.0%	15.0%
Nevada	1/1/2008	Year_00	Slow	7,975	94%	12%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
New Mexico	1/1/2008	Year_00		4,642	74%	7%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Utah	1/1/2008	Year_00	Slow	5,756	75%	9%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	3%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Pacific				128,059	67%	100%							
California	1/1/2008	Year_00	Slow	74,792	78%	58%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Oregon	1/1/2008	Year_00	Slow	17,496	71%	14%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Washington	1/1/2008	Year_00	Slow	31,362	41%	24%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Alaska	1/1/2008	Year_00	Slow	1,768	9%	1%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	2%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%

Table 12- Regional Green Power Penetration as % of eligible Competitive customers

Regional Green Power Penetration as % of Eligible Competitive Customers
calcuated as sum of states' (GP pen % of elig comp customers * % of market comp * power sales)/(regional sales * regional % of market comp)
* - 0 substituted in cell when denominator is 0

Current Conditions

Census Region/State	Case-Specific Direct Access Date	Model Year in 2000	Fast vs. Slow for states with no firm date	Residential Total Sales EIA Table 14 (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	1.7%	6.6%	11.2%	14.7%	14.9%	15.0%	15.0%
Middle Atlantic				104,788	91%	100%	1.5%	6.1%	11.0%	15.0%	15.0%	15.0%	15.0%
East North Central				160,431	84%	100%	0.0%	4.4%	7.7%	12.7%	14.5%	15.0%	15.0%
West North Central				84,066	55%	100%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
South Atlantic				274,833	72%	100%	1.0%	3.8%	5.2%	9.4%	13.5%	15.0%	15.0%
East South Central				100,817	35%	100%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%
S.Atl + ES Central				375,650	62%	100%	1.0%	0.0%	4.9%	9.1%	13.4%	15.0%	15.0%
West South Central				170,993	71%	100%	0.0%	4.0%	7.6%	12.1%	14.5%	15.0%	15.0%
Mountain				64,980	80%	100%	0.0%	4.7%	6.6%	10.9%	13.9%	15.0%	15.0%
Pacific				128,059	67%	100%	0.0%	0.0%	3.0%	8.0%	13.0%	15.0%	15.0%

Appendix D: Green Power Market Assumptions (cont.)

Table 13- Green Power Penetration as % of eligible Regulated customers

Green Power Penetration as % of Eligible Regulated Customers
- assumes .75% to 7.5% (over 10yrs) increase for Regulated customers
- assume non-residential is a constant 25% of residential demand

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	0.75%	**4.50%**	7.50%	7.50%	7.50%	7.50%	7.50%
Maine	3/1/2000	Year_01		3,589	96%	**9%**	0.75%	**4.50%**	7.50%	7.50%	7.50%	7.50%	7.50%
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	2.25%	**6.00%**	7.50%	7.50%	7.50%	7.50%	7.50%
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	2.25%	**6.00%**	7.50%	7.50%	7.50%	7.50%	7.50%
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	0.75%	**4.50%**	7.50%	7.50%	7.50%	7.50%	7.50%
New York	7/1/2001	Year_00		40,240	84%	**38%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	1.50%	**5.25%**	7.50%	7.50%	7.50%	7.50%	7.50%
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	0.00%	**3.00%**	6.75%	7.50%	7.50%	7.50%	7.50%
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	0.00%	**3.00%**	6.75%	7.50%	7.50%	7.50%	7.50%
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	0.75%	**4.50%**	7.50%	7.50%	7.50%	7.50%	7.50%
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	0.00%	**1.50%**	5.25%	7.50%	7.50%	7.50%	7.50%
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	0.00%	**0.00%**	3.75%	7.50%	7.50%	7.50%	7.50%
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Texas	1/1/2002	Year_00		110,434	72%	**65%**	0.00%	**3.00%**	6.75%	7.50%	7.50%	7.50%	7.50%
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	0.00%	**3.75%**	7.50%	7.50%	7.50%	7.50%	7.50%
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Montana	7/1/2004	Year_00		3,722	63%	**6%**	0.00%	**1.50%**	5.25%	7.50%	7.50%	7.50%	7.50%
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	0.00%	**0.00%**	2.25%	6.00%	7.50%	7.50%	7.50%

Table 14- Regional Green Power Penetration as % of eligible Regulated customers

Regional Green Power Penetration as % of Eligible Regulated Customers

calcuated as sum of states' (GP pen % of elig reg customers * (1-% of market comp) * power sales)/(regional sales * (1-regional % of market comp))

Census Region/State	Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* for states with no firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	0.69%	3.29%	6.82%	7.33%	7.50%	7.50%	7.50%
Middle Atlantic				104,788	91%	100%	0.41%	4.12%	7.50%	7.50%	7.50%	7.50%	7.50%
East North Central				160,431	84%	100%	0.00%	0.75%	4.73%	6.82%	7.50%	7.50%	7.50%
West North Central				84,066	55%	100%	0.00%	0.00%	2.25%	6.00%	7.50%	7.50%	7.50%
South Atlantic				274,833	72%	100%	0.04%	0.10%	2.47%	6.17%	7.50%	7.50%	7.50%
East South Central				100,817	35%	100%	0.00%	0.00%	2.25%	6.00%	7.50%	7.50%	7.50%
S.Atl + ES Central				375,650	62%	100%	0.03%	0.07%	2.39%	6.09%	7.50%	7.50%	7.50%
West South Central				170,993	71%	100%	0.00%	0.98%	4.41%	7.10%	7.50%	7.50%	7.50%
Mountain				64,980	80%	100%	0.00%	0.16%	2.66%	6.30%	7.50%	7.50%	7.50%
Pacific				128,059	67%	100%	0.00%	0.00%	2.25%	6.00%	7.50%	7.50%	7.50%

Appendix D: Green Power Market Assumptions (cont.)

Table 15a- Regional Green Power Penetration as % of All eligiblecustomers

Green Power Penetration as % of All Eligible Customers
- calculated as (% penetration of eligible regulated*%access of regulated)+(% penetration of eligible competitive*% access of competitive)
- (table 13*table 7) + (table 11* table 5)

Current Conditions

Census Region/State	FY05 Case-Specific Direct Access Date	Model Year in 2000	Fast vs. Slow For states with no Firm date	Residential Total Sales EIA Table 14 (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%							
Connecticut	7/1/2000	Year_01		10,935	96%	28%	0.00%	4.86%	9.80%	14.63%	14.63%	14.63%	14.63%
Maine	3/1/2000	Year_01		3,589	96%	9%	0.96%	5.83%	10.78%	14.66%	14.66%	14.66%	14.66%
Massachusetts	3/1/1998	Year_03		16,388	85%	42%	2.57%	7.23%	11.96%	13.73%	13.73%	13.73%	13.73%
New_Hampshire	5/1/2001	Year_00		3,384	88%	9%	0.00%	4.57%	9.44%	13.96%	13.96%	13.96%	13.96%
Rhode Island	1/1/1998	Year_03		2,522	99%	7%	2.97%	7.95%	12.93%	14.92%	14.92%	14.92%	14.92%
Vermont	1/1/2008	Year_00	Fast	1,951	78%	5%	0.00%	0.00%	2.63%	7.14%	11.47%	13.12%	13.12%
Middle Atlantic				104,788	91%	100%							
New Jersey	#######	Year_01		23,191	98%	22%	0.98%	5.92%	10.89%	14.82%	14.82%	14.82%	14.82%
New York	7/1/2001	Year_00		40,240	84%	38%	0.00%	4.42%	9.24%	13.60%	13.60%	13.60%	13.60%
Pennsylvania	1/1/1999	Year_02		41,358	95%	39%	1.26%	6.76%	11.68%	14.56%	14.56%	14.56%	14.56%
East North Central				160,431	84%	100%							
Illinois	5/1/2002	Year_00		39,685	88%	25%	0.00%	3.65%	8.48%	13.06%	13.97%	13.97%	13.97%
Indiana	1/1/2008	Year_00	Fast	27,334	73%	17%	0.00%	0.00%	2.53%	6.91%	11.06%	12.62%	12.62%
Michigan	1/1/2002	Year_00		29,808	89%	19%	0.00%	3.68%	8.53%	13.15%	14.06%	14.06%	14.06%
Ohio	1/1/2001	Year_00		44,516	86%	28%	0.00%	4.49%	9.33%	13.75%	13.75%	13.75%	13.75%
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	12%	0.00%	0.00%	2.66%	7.20%	11.58%	13.26%	13.26%
West North Central				84,066	55%	100%							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	14%	0.00%	0.00%	1.94%	6.62%	10.54%	11.99%	11.99%
Kansas	1/1/2008	Year_00	Slow	11,832	73%	14%	0.00%	0.00%	2.02%	6.91%	11.06%	12.62%	12.62%
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	21%	0.00%	0.00%	1.80%	6.03%	9.50%	10.71%	10.71%
Missouri	1/1/2008	Year_00	Slow	28,265	63%	34%	0.00%	0.00%	1.92%	6.52%	10.37%	11.78%	11.78%
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	10%	0.00%	0.00%	1.28%	4.01%	5.90%	6.30%	6.30%
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	4%	0.00%	0.00%	1.79%	6.00%	9.44%	10.64%	10.64%
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	4%	0.00%	0.00%	1.73%	5.76%	9.02%	10.13%	10.13%
South Atlantic				274,833	72%	100%							
Delaware	4/1/2001	Year_00		3,339	71%	1%	0.00%	3.95%	8.63%	12.46%	12.46%	12.46%	12.46%
District of Columbia	1/1/2001	Year_00		1,596	100%	1%	0.00%	5.00%	10.00%	15.00%	15.00%	15.00%	15.00%
Florida	1/1/2008	Year_00	Slow	95,768	77%	35%	0.00%	0.00%	2.06%	7.08%	11.37%	13.00%	13.00%
Georgia	1/1/2008	Year_00	Slow	41,519	51%	15%	0.00%	0.00%	1.79%	6.03%	9.49%	10.70%	10.70%
Maryland	7/1/2000	Year_01		22,407	90%	8%	0.30%	5.59%	10.46%	14.15%	14.15%	14.15%	14.15%
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	16%	0.00%	0.00%	1.96%	6.69%	10.67%	12.14%	12.14%
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	9%	0.00%	0.00%	1.86%	6.29%	9.97%	11.28%	11.28%
Virginia	1/1/2004	Year_00		34,703	83%	13%	0.00%	1.74%	6.39%	10.93%	13.52%	13.52%	13.52%
West Virginia	1/1/2008	Year_00		9,053	99%	3%	0.00%	0.00%	2.29%	7.96%	12.93%	14.91%	14.91%
East South Central				100,817	35%	100%							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	27%	0.00%	0.00%	1.87%	6.31%	10.00%	11.33%	11.33%
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	21%	0.00%	0.00%	1.83%	6.16%	9.72%	10.98%	10.98%
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	16%	0.00%	0.00%	1.72%	5.72%	8.95%	10.04%	10.04%
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	35%	0.00%	0.00%	1.30%	4.08%	6.03%	6.46%	6.46%
West South Central				170,993	71%	100%							
Arkansas	#######	Year_00		14,339	58%	8%	0.00%	0.00%	3.85%	8.01%	11.31%	11.31%	11.31%
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	16%	0.00%	0.00%	2.05%	7.03%	11.27%	12.88%	12.88%
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	11%	0.00%	0.00%	1.97%	6.71%	10.70%	12.18%	12.18%
Texas	1/1/2002	Year_00		110,434	72%	65%	0.00%	3.18%	7.78%	11.79%	12.56%	12.56%	12.56%
Mountain				64,980	80%	100%							
Arizona	1/1/2001	Year_00		21,611	94%	33%	0.00%	4.77%	9.70%	14.44%	14.44%	14.44%	14.44%
Colorado	1/1/2008	Year_00	Slow	12,652	57%	19%	0.00%	0.00%	1.86%	6.29%	9.96%	11.28%	11.28%
Idaho	1/1/2008	Year_00	Slow	6,610	82%	10%	0.00%	0.00%	2.12%	7.30%	11.76%	13.48%	13.48%
Montana	7/1/2004	Year_00		3,722	63%	6%	0.00%	1.43%	5.68%	9.69%	11.80%	11.80%	11.80%
Nevada	1/1/2008	Year_00	Slow	7,975	94%	12%	0.00%	0.00%	2.23%	7.74%	12.55%	14.44%	14.44%
New Mexico	1/1/2008	Year_00		4,642	74%	7%	0.00%	0.00%	2.56%	6.97%	11.18%	12.76%	12.76%
Utah	1/1/2008	Year_00	Slow	5,756	75%	9%	0.00%	0.00%	2.05%	7.02%	11.25%	12.86%	12.86%
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	3%	0.00%	0.00%	1.87%	6.32%	10.02%	11.34%	11.34%
Pacific				128,059	67%	100%							
California	1/1/2008	Year_00	Slow	74,792	78%	58%	0.00%	0.00%	2.62%	7.11%	11.42%	13.07%	13.07%
Oregon	1/1/2008	Year_00	Slow	17,496	71%	14%	0.00%	0.00%	2.00%	6.84%	10.94%	12.48%	12.48%
Washington	1/1/2008	Year_00	Slow	31,362	41%	24%	0.00%	0.00%	1.70%	5.66%	8.84%	9.91%	9.91%
Alaska	1/1/2008	Year_00	Slow	1,768	9%	1%	0.00%	0.00%	1.38%	4.38%	6.56%	7.11%	7.11%
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	2%	0.00%	0.00%	2.30%	8.00%	13.00%	15.00%	15.00%

Table 15b- Regional Green Power Penetration as % of ALL eligible customers

Regional Green Power Penetration as % of Eligible Customers

* - 0 substituted in cell when denominator is 0

Current Conditions

High Case (10^6 kWh) Census Region/State	Model Year in 2000	Base Year ** delayed 2 yrs due to Low Case 1/3/2001	Fast vs. Slow for states with no firm date	Residential Total Sales EIA Table 14 (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	1.49%	6.04%	10.66%	13.91%	14.10%	14.17%	14.17%
Middle Atlantic				104,788	91%	100%	1.10%	5.76%	10.64%	14.28%	14.28%	14.28%	14.28%
East North Central				160,431	84%	100%	0.00%	3.46%	7.25%	11.71%	13.22%	13.65%	13.65%
West North Central				84,066	55%	100%	0.00%	0.00%	1.83%	6.27%	9.93%	11.24%	11.24%
South Atlantic				274,833	72%	100%	0.30%	1.50%	4.01%	8.26%	11.63%	12.76%	12.76%
East South Central				100,817	35%	100%	0.00%	0.00%	1.62%	5.49%	8.57%	9.57%	9.57%
S.Atl + ES Central				375,650	62%	100%	0.30%	1.18%	3.44%	7.66%	10.97%	12.07%	12.07%
West South Central				170,993	71%	100%	0.00%	2.51%	6.28%	10.19%	12.06%	12.48%	12.48%
Mountain				64,980	80%	100%	0.00%	2.87%	5.80%	10.02%	12.51%	13.42%	13.42%
Pacific				128,059	67%	100%	0.00%	0.00%	2.36%	6.81%	10.88%	12.40%	12.40%

Appendix D: Green Power Market Assumptions (cont.)

Table 16- Green Power Penetration as % of All Customers- Total (Regulated and Competitive)

Green Power Penetration as % of All Customers- Total (Regulated and Competitive)
- Calculated as 15a* Table 9

= penetration of GP as % of all eligible customers * % of all customers with access to green power
- assume non-residential is a constant 25% of residential demand

Census Region/State	FY05 Case-Specific Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales* *EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	**100%**							
Connecticut	7/1/2000	Year_01		10,935	96%	**28%**	0.0%	**4.5%**	9.3%	13.9%	13.9%	13.9%	13.9%
Maine	3/1/2000	Year_01		3,589	96%	**9%**	0.9%	**5.5%**	10.3%	14.0%	14.0%	14.0%	14.0%
Massachusetts	3/1/1998	Year_03		16,388	85%	**42%**	1.9%	**5.8%**	10.1%	11.6%	11.6%	11.6%	11.6%
New_Hampshire	5/1/2001	Year_00		3,384	88%	**9%**	0.0%	**3.8%**	8.2%	12.2%	12.2%	12.2%	12.2%
Rhode Island	1/1/1998	Year_03		2,522	99%	**7%**	2.9%	**7.8%**	12.8%	14.8%	14.8%	14.8%	14.8%
Vermont	1/1/2008	Year_00	Fast	1,951	78%	**5%**	0.0%	**0.0%**	1.9%	5.5%	8.9%	10.2%	10.2%
Middle Atlantic				104,788	91%	**100%**							
New Jersey	#######	Year_01		23,191	98%	**22%**	0.9%	**5.7%**	10.6%	14.5%	14.5%	14.5%	14.5%
New York	7/1/2001	Year_00		40,240	84%	**38%**	0.0%	**3.4%**	7.7%	11.3%	11.3%	11.3%	11.3%
Pennsylvania	1/1/1999	Year_02		41,358	95%	**39%**	0.5%	**6.3%**	11.0%	13.7%	13.7%	13.7%	13.7%
East North Central				160,431	84%	**100%**							
Illinois	5/1/2002	Year_00		39,685	88%	**25%**	0.0%	**3.0%**	7.4%	11.4%	12.2%	12.2%	12.2%
Indiana	1/1/2008	Year_00	Fast	27,334	73%	**17%**	0.0%	**0.0%**	1.7%	5.0%	8.1%	9.2%	9.2%
Michigan	1/1/2002	Year_00		29,808	89%	**19%**	0.0%	**3.1%**	7.5%	11.6%	12.4%	12.4%	12.4%
Ohio	1/1/2001	Year_00		44,516	86%	**28%**	0.0%	**3.6%**	7.9%	11.7%	11.7%	11.7%	11.7%
Wisconsin	1/1/2008	Year_00	Fast	19,087	80%	**12%**	0.0%	**0.0%**	2.0%	5.6%	9.2%	10.5%	10.5%
West North Central				84,066	55%	**100%**							
Iowa	1/1/2008	Year_00	Slow	11,855	65%	**14%**	0.0%	**0.0%**	1.0%	4.4%	7.1%	8.1%	8.1%
Kansas	1/1/2008	Year_00	Slow	11,832	73%	**14%**	0.0%	**0.0%**	1.0%	5.0%	8.1%	9.2%	9.2%
Minnesota	1/1/2008	Year_00	Slow	17,378	51%	**21%**	0.0%	**0.0%**	0.9%	3.4%	5.5%	6.2%	6.2%
Missouri	1/1/2008	Year_00	Slow	28,265	63%	**34%**	0.0%	**0.0%**	0.9%	4.2%	6.8%	7.8%	7.8%
Nebraska	1/1/2008	Year_00	Slow	8,160	0%	**10%**	0.0%	**0.0%**	0.7%	2.0%	2.8%	3.0%	3.0%
North Dakota	1/1/2008	Year_00	Slow	3,272	50%	**4%**	0.0%	**0.0%**	0.9%	3.4%	5.5%	6.2%	6.2%
South Dakota	1/1/2008	Year_00	Slow	3,303	44%	**4%**	0.0%	**0.0%**	0.8%	3.1%	5.0%	5.6%	5.6%
South Atlantic				274,833	72%	**100%**							
Delaware	4/1/2001	Year_00		3,339	71%	**1%**	0.0%	**2.4%**	6.2%	8.9%	8.9%	8.9%	8.9%
District of Columbia	1/1/2001	Year_00		1,596	100%	**1%**	0.0%	**5.0%**	10.0%	15.0%	15.0%	15.0%	15.0%
Florida	1/1/2008	Year_00	Slow	95,768	77%	**35%**	0.0%	**0.0%**	1.1%	5.3%	8.7%	10.0%	10.0%
Georgia	1/1/2008	Year_00	Slow	41,519	51%	**15%**	0.0%	**0.0%**	0.9%	3.4%	5.5%	6.2%	6.2%
Maryland	7/1/2000	Year_01		22,407	90%	**8%**	0.0%	**4.8%**	9.3%	12.6%	12.6%	12.6%	12.6%
North Carolina	1/1/2008	Year_00	Slow	42,890	67%	**16%**	0.0%	**0.0%**	1.0%	4.5%	7.3%	8.4%	8.4%
South Carolina	1/1/2008	Year_00	Slow	23,558	57%	**9%**	0.0%	**0.0%**	0.9%	3.8%	6.2%	7.0%	7.0%
Virginia	1/1/2004	Year_00		34,703	83%	**13%**	0.0%	**1.3%**	5.1%	9.0%	11.1%	11.1%	11.1%
West Virginia	1/1/2008	Year_00		9,053	99%	**3%**	0.0%	**0.0%**	1.3%	7.9%	12.8%	14.7%	14.7%
East South Central				100,817	35%	**100%**							
Alabama	1/1/2008	Year_00	Slow	27,327	58%	**27%**	0.0%	**0.0%**	0.9%	3.8%	6.2%	7.1%	7.1%
Kentucky	1/1/2008	Year_00	Slow	21,669	54%	**21%**	0.0%	**0.0%**	0.9%	3.6%	5.8%	6.6%	6.6%
Mississippi	1/1/2008	Year_00	Slow	16,392	43%	**16%**	0.0%	**0.0%**	0.8%	3.0%	4.9%	5.5%	5.5%
Tennessee	1/1/2008	Year_00	Slow	35,428	2%	**35%**	0.0%	**0.0%**	0.7%	2.0%	2.9%	3.1%	3.1%
West South Central				170,993	71%	**100%**							
Arkansas	#######	Year_00		14,339	58%	**8%**	0.0%	**0.0%**	2.3%	5.0%	7.1%	7.1%	7.1%
Louisiana	1/1/2008	Year_00	Slow	26,709	76%	**16%**	0.0%	**0.0%**	1.0%	5.2%	8.5%	9.7%	9.7%
Oklahoma	1/1/2008	Year_00	Slow	19,511	68%	**11%**	0.0%	**0.0%**	1.0%	4.5%	7.4%	8.4%	8.4%
Texas	1/1/2002	Year_00		110,434	72%	**65%**	0.0%	**2.0%**	5.6%	8.6%	9.1%	9.1%	9.1%
Mountain				64,980	80%	**100%**							
Arizona	1/1/2001	Year_00		21,611	94%	**33%**	0.0%	**4.3%**	9.0%	13.4%	13.4%	13.4%	13.4%
Colorado	1/1/2008	Year_00	Slow	12,652	57%	**19%**	0.0%	**0.0%**	0.9%	3.8%	6.2%	7.0%	7.0%
Idaho	1/1/2008	Year_00	Slow	6,610	82%	**10%**	0.0%	**0.0%**	1.1%	5.9%	9.6%	11.0%	11.0%
Montana	7/1/2004	Year_00		3,722	63%	**6%**	0.0%	**0.7%**	3.6%	6.4%	7.8%	7.8%	7.8%
Nevada	1/1/2008	Year_00	Slow	7,975	94%	**12%**	0.0%	**0.0%**	1.2%	7.2%	11.6%	13.4%	13.4%
New Mexico	1/1/2008	Year_00		4,642	74%	**7%**	0.0%	**0.0%**	1.8%	5.1%	8.3%	9.5%	9.5%
Utah	1/1/2008	Year_00	Slow	5,756	75%	**9%**	0.0%	**0.0%**	1.0%	5.2%	8.5%	9.7%	9.7%
Wyoming	1/1/2008	Year_00	Slow	2,013	58%	**3%**	0.0%	**0.0%**	0.9%	3.9%	6.3%	7.1%	7.1%
Pacific				128,059	67%	**100%**							
California	1/1/2008	Year_00	Slow	74,792	78%	**58%**	0.0%	**0.0%**	1.9%	5.4%	8.8%	10.1%	10.1%
Oregon	1/1/2008	Year_00	Slow	17,496	71%	**14%**	0.0%	**0.0%**	1.0%	4.8%	7.9%	9.0%	9.0%
Washington	1/1/2008	Year_00	Slow	31,362	41%	**24%**	0.0%	**0.0%**	0.8%	3.0%	4.8%	5.4%	5.4%
Alaska	1/1/2008	Year_00	Slow	1,768	9%	**1%**	0.0%	**0.0%**	0.7%	2.1%	3.1%	3.4%	3.4%
Hawaii	1/1/2008	Year_00	Slow	2,641	100%	**2%**	0.0%	**0.0%**	1.3%	8.0%	13.0%	15.0%	15.0%

Appendix D: Green Power Market Assumptions (cont.)

Table 17a- Regional Green Power Penetration as % of All Customers- Total (Regulated and Competitive)

Census Region/State	Case-SpeciFic Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Regional Green Power Penetration as % of All Customers- Total (Regulated and Competitive) - assume non-residential is a constant 25% of residential demand Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	**1.07%**	**5.09%**	**9.50%**	**12.42%**	**12.59%**	**12.65%**	**12.65%**
Middle Atlantic				104,788	91%	100%	**0.41%**	**5.05%**	**9.65%**	**12.96%**	**12.96%**	**12.96%**	**12.96%**
East North Central				160,431	84%	100%	**0.00%**	**2.30%**	**5.94%**	**9.72%**	**11.02%**	**11.37%**	**11.37%**
West North Central				84,066	55%	100%	**0.00%**	**0.00%**	**0.90%**	**3.87%**	**6.26%**	**7.09%**	**7.09%**
South Atlantic				274,833	72%	100%	**0.00%**	**0.61%**	**2.31%**	**6.03%**	**8.60%**	**9.44%**	**9.44%**
East South Central				100,817	35%	100%	**0.00%**	**0.00%**	**0.81%**	**3.01%**	**4.76%**	**5.31%**	**5.31%**
S.Atl + ES Central				375,650	62%	100%	**0.00%**	**0.45%**	**1.91%**	**5.22%**	**7.57%**	**8.33%**	**8.33%**
West South Central				170,993	71%	100%	**0.00%**	**1.27%**	**4.07%**	**7.27%**	**8.65%**	**8.96%**	**8.96%**
Mountain				64,980	80%	100%	**0.00%**	**1.47%**	**3.89%**	**7.98%**	**10.05%**	**10.78%**	**10.78%**
Pacific				128,059	67%	100%	**0.00%**	**0.00%**	**1.49%**	**4.75%**	**7.72%**	**8.80%**	**8.80%**

Table 17b- (check) Regional Green Power Penetration as % of All Customers- Total (Regulated and Competitive)

Census Region/State	Case-SpeciFic Direct Access Date	*Model Year in 2000*	*Fast vs. Slow* For states with no Firm date	*Residential Total Sales EIA Table 14* (10^6 kWh) Actual (1998)	% of sales to IOU	% of region's electricity use	Regional Green Power Penetration as % of All Customers- Total (Regulated and Competitive) - Calculated as Table 15 * Table 10 (% penetration of all eligible customers * % of all customers with green power access) - assume non-residential is a constant 25% of residential demand Current Conditions 2000	2005	2010	2015	2020	2025	2030
New England				38,769	90%	100%	**1.07%**	**5.09%**	**9.50%**	**12.42%**	**12.59%**	**12.65%**	**12.65%**
Middle Atlantic				104,788	91%	100%	**0.41%**	**5.05%**	**9.65%**	**12.96%**	**12.96%**	**12.96%**	**12.96%**
East North Central				160,431	84%	100%	**0.00%**	**2.30%**	**5.94%**	**9.72%**	**11.02%**	**11.37%**	**11.37%**
West North Central				84,066	55%	100%	**0.00%**	**0.00%**	**0.90%**	**3.87%**	**6.26%**	**7.09%**	**7.09%**
South Atlantic				274,833	72%	100%	**0.00%**	**0.61%**	**2.31%**	**6.03%**	**8.60%**	**9.44%**	**9.44%**
East South Central				100,817	35%	100%	**0.00%**	**0.00%**	**0.81%**	**3.01%**	**4.76%**	**5.31%**	**5.31%**
S.Atl + ES Central				375,650	62%	100%	**0.00%**	**0.45%**	**1.91%**	**5.22%**	**7.57%**	**8.33%**	**8.33%**
West South Central				170,993	71%	100%	**0.00%**	**1.27%**	**4.07%**	**7.27%**	**8.65%**	**8.96%**	**8.96%**
Mountain				64,980	80%	100%	**0.00%**	**1.47%**	**3.89%**	**7.98%**	**10.05%**	**10.78%**	**10.78%**
Pacific				128,059	67%	100%	**0.00%**	**0.00%**	**1.49%**	**4.75%**	**7.72%**	**8.80%**	**8.80%**

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy

		2000	2005	2010	2015	2020	2025	2030
Direct-Fired Biomass								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
New England	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Mid. Atlantic	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
E. N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
W.N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
S. Atl. & E.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
W.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%

		2000	2005	2010	2015	2020	2025	2030
Biomass Gasification								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
New England	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Mid. Atlantic	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
E. N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
W.N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
S. Atl. & E.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
W.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%

		2000	2005	2010	2015	2020	2025	2030
Landfill Gas								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
New England	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Mid. Atlantic	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
E. N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
W.N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
S. Atl. & E.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
W.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy (cont.)

Flash Geothermal		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New England	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	92.00%	93.00%	95.00%	95.50%	96.00%	96.00%	96.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	92.00%	93.00%	95.00%	95.50%	96.00%	96.00%	96.00%

Binary Geothermal		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	92.00%	93.00%	95.00%	95.50%	96.00%	96.00%	96.00%
New England	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	92.00%	93.00%	95.00%	95.50%	96.00%	96.00%	96.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	92.00%	93.00%	95.00%	95.50%	96.00%	96.00%	96.00%

Hot Dry Rock		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	81.00%	82.00%	83.00%	84.00%	85.00%	85.00%	85.00%
New England	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	81.00%	82.00%	83.00%	84.00%	85.00%	85.00%	85.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	81.00%	82.00%	83.00%	84.00%	85.00%	85.00%	85.00%

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy (cont.)

		2000	2005	2010	2015	2020	2025	2030
CSP Trough								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	33.30%	41.70%	51.20%	51.20%	51.20%	51.20%	51.20%
New England	Adjustment	0.69	0.69	0.69	0.69	0.69	0.69	0.69
	Cap Factor	23.03%	28.84%	35.41%	35.41%	35.41%	35.41%	35.41%
Mid. Atlantic	Adjustment	0.70	0.70	0.70	0.70	0.70	0.70	0.70
	Cap Factor	23.42%	29.32%	36.00%	36.00%	36.00%	36.00%	36.00%
E. N. Central	Adjustment	0.72	0.72	0.72	0.72	0.72	0.72	0.72
	Cap Factor	23.95%	29.99%	36.82%	36.82%	36.82%	36.82%	36.82%
W.N. Central	Adjustment	0.81	0.81	0.81	0.81	0.81	0.81	0.81
	Cap Factor	27.07%	33.90%	41.62%	41.62%	41.62%	41.62%	41.62%
S. Atl. & E.S. Central	Adjustment	0.75	0.75	0.75	0.75	0.75	0.75	0.75
	Cap Factor	25.05%	31.37%	38.52%	38.52%	38.52%	38.52%	38.52%
W.S. Central	Adjustment	0.91	0.91	0.91	0.91	0.91	0.91	0.91
	Cap Factor	30.42%	38.09%	46.77%	46.77%	46.77%	46.77%	46.77%
Mountain	Adjustment	0.98	0.98	0.98	0.98	0.98	0.98	0.98
	Cap Factor	32.71%	40.96%	50.29%	50.29%	50.29%	50.29%	50.29%
Pacific	Adjustment	0.84	0.84	0.84	0.84	0.84	0.84	0.84
	Cap Factor	27.81%	34.82%	42.76%	42.76%	42.76%	42.76%	42.76%

		2000	2005	2010	2015	2020	2025	2030
CSP Dish Hybrid								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
New England	Adjustment	0.91	0.91	0.91	0.91	0.91	0.91	0.91
	Cap Factor	45.28%	45.28%	45.28%	45.28%	45.28%	45.28%	45.28%
Mid. Atlantic	Adjustment	0.92	0.92	0.92	0.92	0.92	0.92	0.92
	Cap Factor	45.95%	45.95%	45.95%	45.95%	45.95%	45.95%	45.95%
E. N. Central	Adjustment	0.94	0.94	0.94	0.94	0.94	0.94	0.94
	Cap Factor	46.94%	46.94%	46.94%	46.94%	46.94%	46.94%	46.94%
W.N. Central	Adjustment	1.06	1.06	1.06	1.06	1.06	1.06	1.06
	Cap Factor	53.23%	53.23%	53.23%	53.23%	53.23%	53.23%	53.23%
S. Atl. & E.S. Central	Adjustment	0.98	0.98	0.98	0.98	0.98	0.98	0.98
	Cap Factor	49.08%	49.08%	49.08%	49.08%	49.08%	49.08%	49.08%
W.S. Central	Adjustment	1.19	1.19	1.19	1.19	1.19	1.19	1.19
	Cap Factor	59.71%	59.71%	59.71%	59.71%	59.71%	59.71%	59.71%
Mountain	Adjustment	1.29	1.29	1.29	1.29	1.29	1.29	1.29
	Cap Factor	64.28%	64.28%	64.28%	64.28%	64.28%	64.28%	64.28%
Pacific	Adjustment	1.09	1.09	1.09	1.09	1.09	1.09	1.09
	Cap Factor	54.46%	54.46%	54.46%	54.46%	54.46%	54.46%	54.46%

		2000	2005	2010	2015	2020	2025	2030
CSP - Solar Central Receiver								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	43.00%	44.00%	65.00%	71.00%	77.00%	77.00%	77.00%
New England	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	1.06	1.06	1.06	1.06	1.06	1.06	1.06
	Cap Factor	45.78%	46.84%	69.20%	75.59%	81.97%	81.97%	81.97%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	1.19	1.19	1.19	1.19	1.19	1.19	1.19
	Cap Factor	51.35%	52.54%	77.62%	84.78%	91.95%	91.95%	91.95%
Mountain	Adjustment	1.29	1.29	1.29	1.29	1.29	1.29	1.29
	Cap Factor	55.28%	56.57%	83.57%	91.28%	99.00%	99.00%	99.00%
Pacific	Adjustment	1.09	1.09	1.09	1.09	1.09	1.09	1.09
	Cap Factor	46.84%	47.92%	70.80%	77.33%	83.87%	83.87%	83.87%

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy (cont.)

		2000	2005	2010	2015	2020	2025	2030
CSP - Solar Central Receiver								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New England	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pacific	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

		2000	2005	2010	2015	2020	2025	2030
CSP Dish								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New England	Adjustment	0.91	0.91	0.91	0.91	0.91	0.91	0.91
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	0.92	0.92	0.92	0.92	0.92	0.92	0.92
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	0.94	0.94	0.94	0.94	0.94	0.94	0.94
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	1.06	1.06	1.06	1.06	1.06	1.06	1.06
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.98	0.98	0.98	0.98	0.98	0.98	0.98
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	1.19	1.19	1.19	1.19	1.19	1.19	1.19
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	1.29	1.29	1.29	1.29	1.29	1.29	1.29
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pacific	Adjustment	1.09	1.09	1.09	1.09	1.09	1.09	1.09
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy (cont.)

Residential PV (Neighborhood ownership)

		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	20.50%	20.50%	20.50%	20.50%	20.50%	20.50%	20.50%
New England	Adjustment	0.92	0.92	0.92	0.92	0.92	0.92	0.92
	Cap Factor	18.88%	18.88%	18.88%	18.88%	18.88%	18.88%	18.88%
Mid. Atlantic	Adjustment	0.93	0.93	0.93	0.93	0.93	0.93	0.93
	Cap Factor	19.09%	19.09%	19.09%	19.09%	19.09%	19.09%	19.09%
E. N. Central	Adjustment	0.95	0.95	0.95	0.95	0.95	0.95	0.95
	Cap Factor	19.37%	19.37%	19.37%	19.37%	19.37%	19.37%	19.37%
W.N. Central	Adjustment	1.05	1.05	1.05	1.05	1.05	1.05	1.05
	Cap Factor	21.46%	21.46%	21.46%	21.46%	21.46%	21.46%	21.46%
S. Atl. & E.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	20.54%	20.54%	20.54%	20.54%	20.54%	20.54%	20.54%
W.S. Central	Adjustment	1.17	1.17	1.17	1.17	1.17	1.17	1.17
	Cap Factor	23.96%	23.96%	23.96%	23.96%	23.96%	23.96%	23.96%
Mountain	Adjustment	1.22	1.22	1.22	1.22	1.22	1.22	1.22
	Cap Factor	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Pacific	Adjustment	1.07	1.07	1.07	1.07	1.07	1.07	1.07
	Cap Factor	22.03%	22.03%	22.03%	22.03%	22.03%	22.03%	22.03%

Central Station PV (Thin Film)

		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	20.70%	20.70%	20.70%	20.70%	20.70%	20.70%	20.70%
New England	Adjustment	0.92	0.92	0.92	0.92	0.92	0.92	0.92
	Cap Factor	19.07%	19.07%	19.07%	19.07%	19.07%	19.07%	19.07%
Mid. Atlantic	Adjustment	0.93	0.93	0.93	0.93	0.93	0.93	0.93
	Cap Factor	19.28%	19.28%	19.28%	19.28%	19.28%	19.28%	19.28%
E. N. Central	Adjustment	0.95	0.95	0.95	0.95	0.95	0.95	0.95
	Cap Factor	19.56%	19.56%	19.56%	19.56%	19.56%	19.56%	19.56%
W.N. Central	Adjustment	1.05	1.05	1.05	1.05	1.05	1.05	1.05
	Cap Factor	21.67%	21.67%	21.67%	21.67%	21.67%	21.67%	21.67%
S. Atl. & E.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	20.74%	20.74%	20.74%	20.74%	20.74%	20.74%	20.74%
W.S. Central	Adjustment	1.17	1.17	1.17	1.17	1.17	1.17	1.17
	Cap Factor	24.19%	24.19%	24.19%	24.19%	24.19%	24.19%	24.19%
Mountain	Adjustment	1.22	1.22	1.22	1.22	1.22	1.22	1.22
	Cap Factor	25.19%	25.19%	25.19%	25.19%	25.19%	25.19%	25.19%
Pacific	Adjustment	1.07	1.07	1.07	1.07	1.07	1.07	1.07
	Cap Factor	22.25%	22.25%	22.25%	22.25%	22.25%	22.25%	22.25%

Concentrator PV

		2000	2005	2010	2015	2020	2025	2030
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	24.20%	24.20%	24.20%	24.20%	24.20%	24.20%	24.20%
New England	Adjustment	0.90	0.90	0.90	0.90	0.90	0.90	0.90
	Cap Factor	21.86%	21.86%	21.86%	21.86%	21.86%	21.86%	21.86%
Mid. Atlantic	Adjustment	0.92	0.92	0.92	0.92	0.92	0.92	0.92
	Cap Factor	22.23%	22.23%	22.23%	22.23%	22.23%	22.23%	22.23%
E. N. Central	Adjustment	0.94	0.94	0.94	0.94	0.94	0.94	0.94
	Cap Factor	22.74%	22.74%	22.74%	22.74%	22.74%	22.74%	22.74%
W.N. Central	Adjustment	1.06	1.06	1.06	1.06	1.06	1.06	1.06
	Cap Factor	25.70%	25.70%	25.70%	25.70%	25.70%	25.70%	25.70%
S. Atl. & E.S. Central	Adjustment	0.98	0.98	0.98	0.98	0.98	0.98	0.98
	Cap Factor	23.78%	23.78%	23.78%	23.78%	23.78%	23.78%	23.78%
W.S. Central	Adjustment	1.19	1.19	1.19	1.19	1.19	1.19	1.19
	Cap Factor	28.88%	28.88%	28.88%	28.88%	28.88%	28.88%	28.88%
Mountain	Adjustment	1.28	1.28	1.28	1.28	1.28	1.28	1.28
	Cap Factor	31.05%	31.05%	31.05%	31.05%	31.05%	31.05%	31.05%
Pacific	Adjustment	1.09	1.09	1.09	1.09	1.09	1.09	1.09
	Cap Factor	26.40%	26.40%	26.40%	26.40%	26.40%	26.40%	26.40%

Appendix E: Regional Adjustments to Capacity Factors and Cost of Energy (cont.)

		2000	2005	2010	2015	2020	2025	2030
Wind - Class 5- dropped								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New England	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mid. Atlantic	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
E. N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

		2000	2005	2010	2015	2020	2025	2030
Wind - Class 4 and Class 6 Average								
National	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
New England	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
Mid. Atlantic	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
E. N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
W.N. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
S. Atl. & E.S. Central	Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Cap Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
W.S. Central	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
Mountain	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%
Pacific	Adjustment	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Cap Factor	36.60%	42.00%	48.10%	48.70%	50.50%	49.60%	48.80%