Final Documentation Report for

FY2004 GPRA Metrics

Subtask 5

Office of Energy Efficiency and Renewable Energy
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Table of Contents

1. **Program Chapters**
    a. Overview
    b. Solar Programs
        i. Solar Buildings
        ii. Photovoltaics
    c. Biomass
    d. Wind
    e. Geothermal
    f. Distributed Energy Resources

2. **Appendices**
    a. Market Segmentation
    b. Overview of Modeling Framework
    c. Green Power Market Model

Overview of FY 2004 Benefits Analysis

The Office of Energy Efficiency and Renewable Energy's (EERE) Renewable and Distributed Energy R&D programs manage research in two broad areas: 1) Energy Supply Technologies; and 2) Electricity Delivery. Several different approaches are required to estimate the benefits of this wide array of programs. The analytical approaches used for FY 2004 are documented in this report, as are the results of these analyses. This chapter provides a broad overview of the approaches taken for each of the two EERE research areas. Greater detail for each EERE Renewable and Distributed Energy program is provided later in this report in program-specific discussions.

Energy Supply Technology Programs

EERE manages six renewable energy technology programs – photovoltaics (PV), biopower, wind, geothermal, solar buildings and hydropower. The five electricity-generating technologies (not including hydropower which is not part of this analysis) were analyzed within the segmentation framework shown in Figure 1. The Solar Buildings program benefits, although shown in Figure 1, were analyzed using a different approach because solar building technologies produce thermal energy and not electricity. This different approach is described later in this report in the Solar Programs chapter. The benefits of the Distributed Energy and Electric Reliability (DEER) program are also estimated as part of the framework shown in Figure 1.

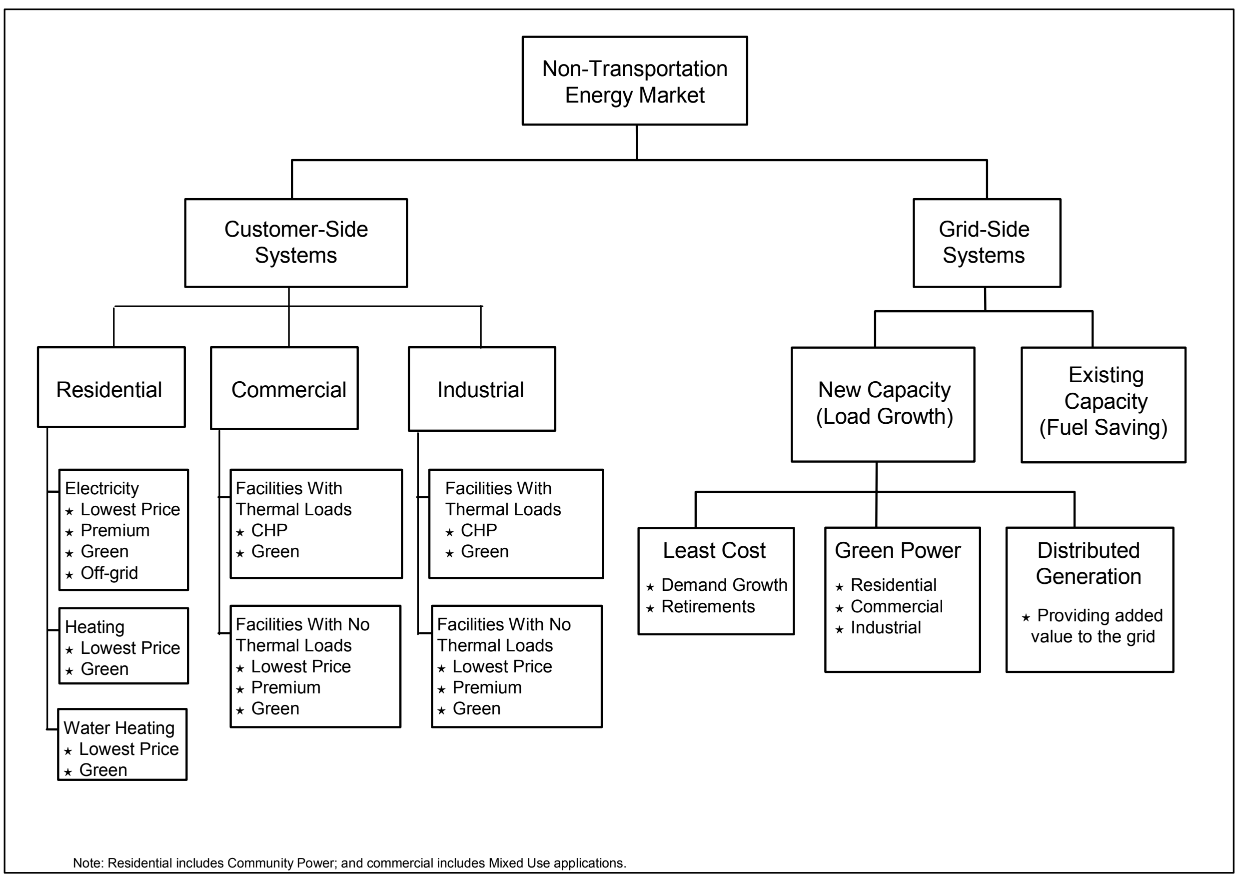

Figure 1 – Market Segmentation for EERE's Renewable and Distributed Energy Programs' Benefits Analysis

The U.S. non-transportation energy market was segmented into: 1) Grid-Side Systems -- systems that are on the grid side of the meter, and owned by utilities or other power suppliers; and 2) Customer-Side Systems -- systems installed at customer locations on the customer side of the meter. Figure 2 shows how the various market segments were analyzed to calculate EERE's Renewable and Distributed Energy programs benefits.

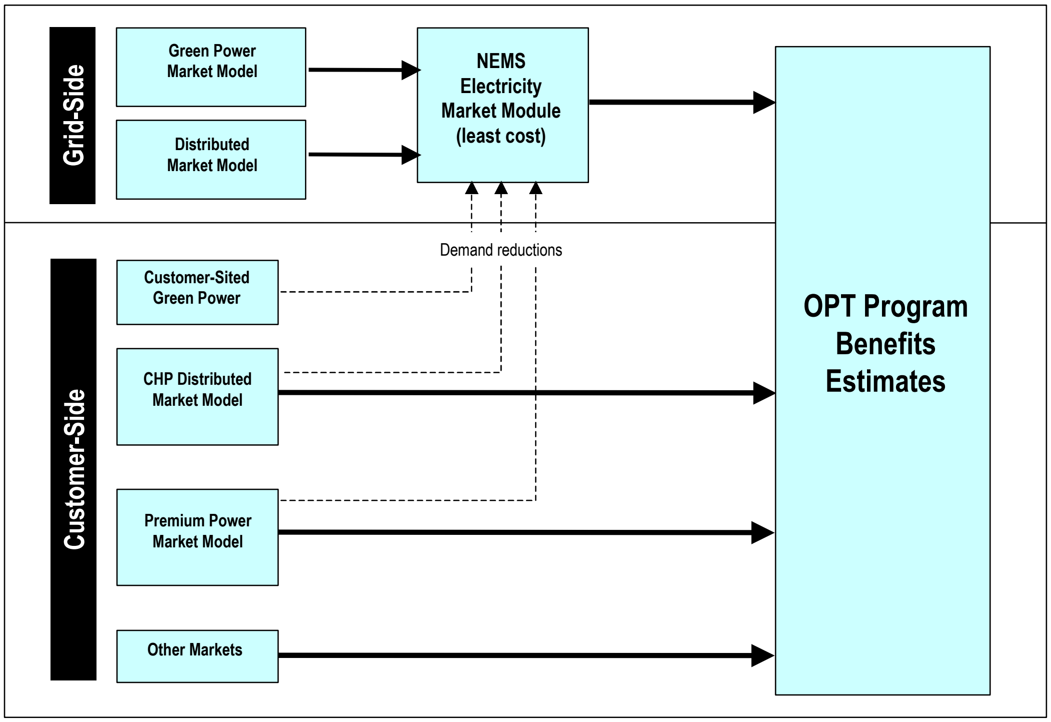

Figure 2 - Analysis Framework for Estimating EERE's Renewable and Distributed Energy Programs Benefits

Grid-Side Market Segment

Figure 3 shows a detailed breakout of the Grid-Side Market segment. The five electricity-generating technologies fall into three primary market segments as follows:

Least-Cost Power

The least cost segment refers to the bulk power market, which has traditionally been the province of the regulated utility industry. In analyzing this segment, growing demand and the need to replace retiring plants is met by projecting the installation of a mixture of power plants. The mixture chosen to meet this growing demand may have many attributes, but the primary one is that the lowest-cost option is typically selected through a detailed analysis process that compares all available options, both renewable and conventional.

Although this segment of the market may in the future be implemented through competitive bidding into a power pool or through bilateral contracts between suppliers and consumers, it will still be likely that the lowest cost option will capture the largest portion of the market. This segment of the market also includes renewables that could be installed to supply electricity at a cost lower than the variable operating cost of existing capacity (commonly referred to as the fuel-saving mode).

For EERE's Renewable and Distributed Energy programs analyses, the National Energy Modeling System (NEMS) is used to estimate future generating technology use in this market segment. This is the same analysis approach as that used by EIA for the Annual Energy Outlook, and EIA's Annual Energy Outlook (AEO) 2002 reference case is used as the baseline for this analysis. OnLocation, Inc. (OnLocation) runs NEMS for EERE, making significant modifications to EIA's technology assumptions and EIA's approaches to characterizing renewables' ability to compete in the competitive market creating NEMS-GPRA04. These changes are believed to characterize EERE's renewable technologies more accurately. An important change, which is common to all five generating technologies, is the use of technology data from the EPRI/DOE *Renewable Energy Technology Characterizations* report, or program updates to this report. The difference from the NEMS-GPRA04 run and the baseline AEO02 run represents the program's expected impact on the market.

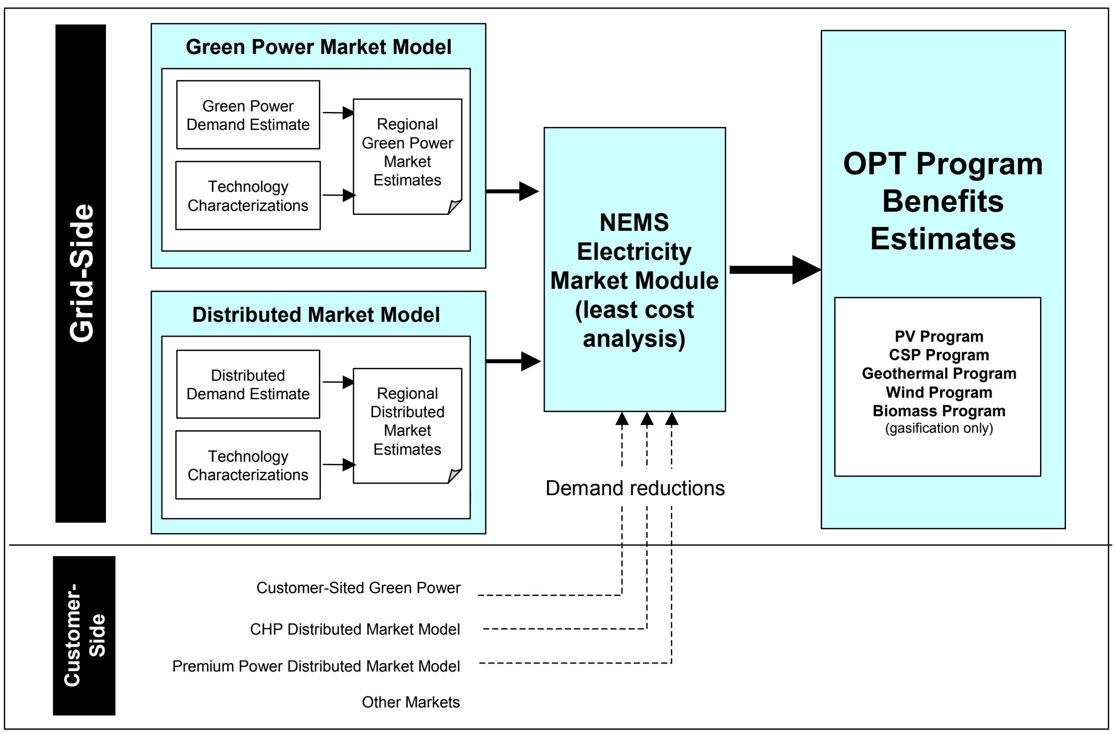

Figure 3 - Analysis Detail for Grid-Side Market Benefits Estimates

A variety of technology-specific changes have also been made. These changes had the greatest impact on the wind and geothermal technology projections, resulting in increased penetration of each when compared to the AEO projections. The technology-specific changes made are described in this report in the appropriate program discussion in later chapters.

Green Power

EERE sponsored the development of a Green Power Market Model (GPMM) by Princeton Energy Resources International (PERI). In this model, the projected green power market size is allocated to the various EERE renewable technologies using an algorithm similar to that, which is used by NEMS. The allocation is performed using a logit function approach to calculating market sharing. The logit function uses the various competing technologies' levelized cost of energy to determine which will be chosen by green power suppliers in a particular region to meet the demand for green power in that region.

The size and timing of the overall green market are key assumptions made for this analysis. The set of assumptions for electricity market restructuring from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*, a recent report by Blair Swezey et al. completed for the National Renewable Energy Laboratory (NREL), continued to be used for this year's analysis. (4) These assumptions include the dates for initiation of market restructuring as well as the assumed green power penetration rates, a change in the time periods tracked in the analysis, and a new method for calculating funds from program participants.

Several changes from last year's assumptions have been included this year. New technology characterizations for wind, class 4 and 6 data averaged, and CSP, trough and power tower data, were taken from program revisions to the *Renewable Energy Technology Characterizations*. Additionally, the regional economic sectors' energy consumption and prices were updated according to the new Energy Information Administration's (EIA) assumptions for the *Annual Energy Outlook 2002* (AEO 2002). Finally, PERI included both additions and subtractions to the green capacity values for the Million Solar Roofs (MSR) capacity additions, and EIA "floors" builds.

A detailed discussion of this analysis and its results can be found in Appendix C. The results of the GPMM runs were explicitly included in the NEMS runs by specifying the green capacity as planned capacity. The effect of this exogenous determination is to reduce future levels of new demand such that when NEMS is run the projections of new conventional capacity and new least-cost renewables are lower than in the base case where no green capacity is explicitly included.

Distributed Generation

Grid-Side Distributed Generation Market benefits are realized when technologies are strategically installed in locations where they can provide benefits to the distribution system beyond the basic commodity supply benefits. An example of such a benefit is the ability to defer, or potentially avoid, a distribution system upgrade. This Distributed Generation Market has yet to materialize for renewables, although a number of EERE programs are working to facilitate renewable penetration into this sub-segment.

<u>Customer-Side Market Segment</u>

Figure 4 shows a detailed breakout of the Customer-Side Market segment.

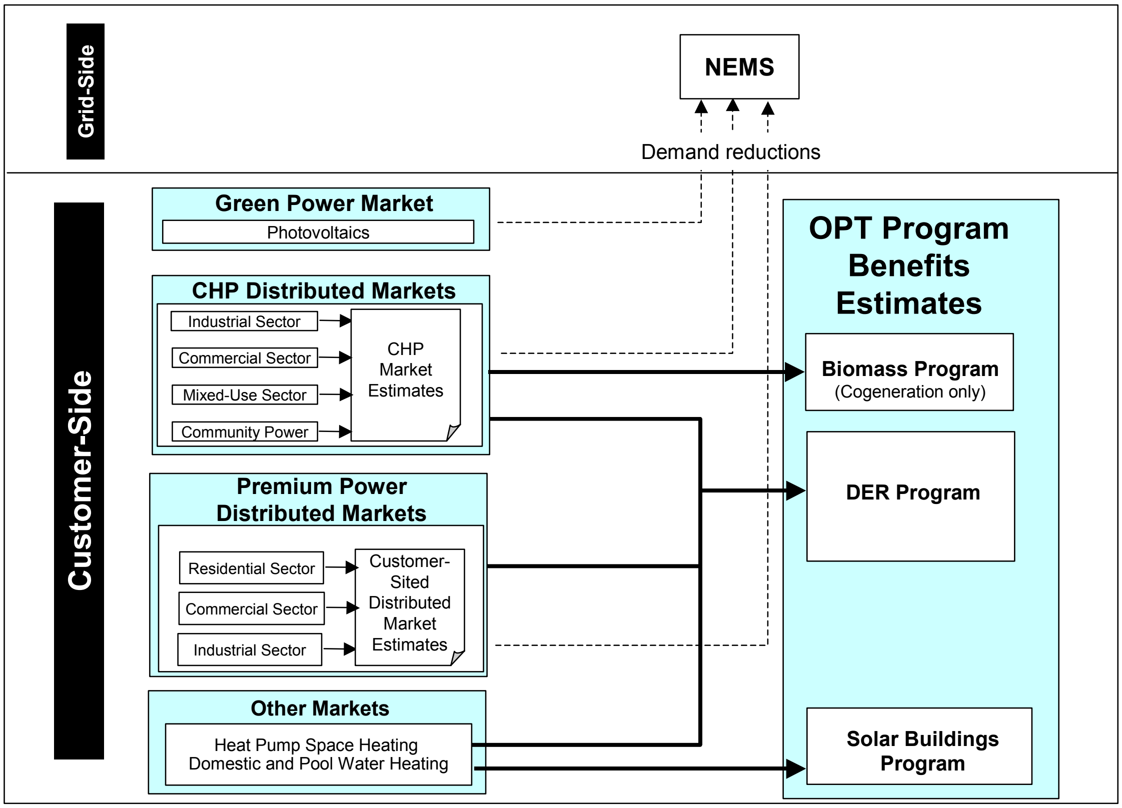

Figure 4 - Analysis Detail for Customer-Side Benefits Estimates.

Green Power

Photovoltaics (PV) was the sole option examined for residential and commercial customer-side green power installations. Although other renewable technologies may well be installed in the residential and commercial sub-segments in the future, PV appears to be at the moment the only technology with significant early market momentum, largely due to the Million Solar Roofs (MSR) program. There may also be small numbers of customer-sited PV systems that are not actually owned by the customer. The extent of PV penetration into the customer-sited market segment was projected to be very closely tied to the 2010 goal of the MSR program.

Overall, although customer-sited PV systems represented the vast majority of projected PV installations for the FY 2004 benefits analysis, customer-sited renewables accounted for only a small portion of all projected renewable penetration.

Combined Heat and Power

The Customer-Side Market segment also includes combined heat and power (CHP, or cogeneration) applications. In these applications, commercial and industrial facilities are equipped to produce both power and thermal energy. The DEER program's benefits are estimated by the NEMS for this market segment. Also estimated as part of the CHP market, biomass cogeneration in the industrial market sub-segment was the other customer-sited renewable technology analyzed. Biomass cogeneration is reported as part of the DEER benefits, and not in the biopower program's benefits totals. This application is particularly suitable to pulp and paper mills, where a prevalence of free fuel, in the form of biomass waste, and the need for process heat makes cogeneration particularly attractive. This market opportunity for biopower increased rapidly in the 1980s with the enactment of PURPA, but as PURPA expired and sites with the greatest potential had been used, the market opportunity has leveled off. The Energy Information Administration (EIA) using NEMS projects only modest future expansion in this sub-segment. The other biopower technologies: direct-fired, and gasification-based generation are electricity-generating technologies and are handled under the grid-side market segment.

Premium Power Distributed

On the Customer-Side, there are opportunities for providing power in applications where the customer is willing to pay a premium for higher quality power, for power with higher reliability, or for power with greater certainty of future price stability. There is no projected penetration of renewable energy power technologies into this market segment for GPRA reporting. More-conventional technologies, using natural gas, were deemed more likely to be used for premium power applications for the foreseeable future. Although not modeled, it should be noted that some "conventional" DEER technologies could also meet the needs of this market.

Other Markets

Other Markets in the Customer-Side Market include markets for solar domestic hot water (SDHW) and solar pool heating (SPH) technologies. These two technologies comprise the Solar Buildings program and represent almost the entire end use for solar thermal collectors. Benefits are derived from the natural gas and electricity displaced that conventionally fuels these heating requirements.

Electricity Delivery Programs

The benefits of the EERE electricity delivery programs cannot be estimated within the framework described above, and must be estimated using various techniques developed by program personnel or their contractors. Many of the programs formerly reported separately under Electricity Delivery Programs, such as High Temperature Superconductivity (HTS), Renewable Energy Production Incentive (REPI), Transmission reliability, Energy Storage, Distribution and Interconnection, and Distributed Generation, have been incorporated into the new DEER program. As such, the benefits of these programs are reported under the DEER program. DEER benefits are calculated from the CHP capacity and generation additions modeled in NEMS. Additionally, the Hydrogen program does not receive any credit for hydrogen fuel cell penetration expected in the CHP market. This capacity is credited to the DEER program.

Table 1 summarizes the current status of programs formerly reported under the Electricity Delivery Programs, and the approaches now used to characterize their benefits for this analysis.

Table 1. Approaches Used For Prior Benefits Estimates of EERE Electricity Delivery Programs.

Program Element	Benefits Estimation Approach
Hydrogen	For FY2004, the program's benefit analysis was done by characterizations from OTT. In year's past, OPT had PERI do an off-line analysis of fuel cell and electric cars, with a portion of the benefits given to the hydrogen program. A market penetration model was developed to estimate the penetration of fuel cell-powered passenger cars and SUVs into both high-value and ZEV mandate markets. In the FY2003 analysis, the Hydrogen program claimed a portion of the benefits of the DER program from 2015 to 2030, with the reasoning that hydrogen technologies are expected to penetrate in this market segment in the form of hydrogen-fueled fuel cells. However, in the FY2004, all hydrogen fuel cell capacity penetration is credited to the DEER program.
High Temperature Superconductivity (HTS), Renewable Energy Production Incentive (REPI), Transmission reliability, Energy Storage, Distribution and Interconnection, and Distributed Generation	These programs are now included in the DEER program. All benefits are characterized in the DEER program chapter.

Program Summary Tables

A summary of the estimated benefits from the Energy Supply Technology Programs is presented in Table 2. The table shows capacity projections which are cumulative, but that have been calculated against the *AEO 2002* baseline. In other words, these results do not include the installed capacity base as of the end of 2002 or the capacity projected in the *AEO 2002*. These capacity projections form the basis for the estimation of the various GPRA metrics for the five generating technology programs: Photovoltaics, Biomass, Wind, Geothermal and DEER.

Annual electricity production for each technology was estimated in NEMS from these capacity projections, and from appropriate capacity factors for each technology. From the annual energy production, primary energy displacement, energy cost savings, carbon displacement, NOx displacement, and SOx displacement were calculated. The *GPRA Data Call: Fiscal Year 2004* guidance document (Appendix D) was used as the source for information on fuel mix displaced, emissions factors, average grid heat rates, fuel prices, etc.

Table 2. Summary of Benefits Estimates for Energy Supply Technology Programs

	2005	2010	2015	2020	2025	2030
Cumulative Capacity Installed above AEO 2002 Baseline (thousands of MW)						
Photovoltaics	0.20	0.95	2.95	4.95	7.00	9.00
Biopower	0.05	0.19	0.37	0.55	0.75	0.90
Wind	1.50	4.65	19.2	33.8	48.5	63.0
Geothermal	0.05	1.80	4.20	6.65	9.10	11.6
Distributed Energy and Electric Reliability	2.30	7.45	16.3	25.0	33.8	42.6
Annual Energy Production (billions of kilowatt-hours/year)						
Photovoltaics	0.35	1.75	5.30	8.85	12.4	16.0
Biopower[1]	0.32	1.30	2.45	3.65	4.85	6.05
Wind	8.05	22.8	85.5	148	211	273
Geothermal	0.40	14.6	34.2	54.0	73.5	93.0
Distributed Energy and Electric Reliability	16.7	54.0	117	180	243	307

1) Biomass Direct Electricity Displaced does not include generation from cofiring capacity, as this is not new capacity, but rather is considered to be a fuel switch for existing or planned capacity, which is addressed as fossil energy displacement.

Table 2. Summary of Benefits Analyses for Energy Supply Technology Programs (cont.)

	2005	2010	2015	2020	2025	2030
Annual Primary Energy Displacement (Trillion Btu/year)						
Total Solar Program	4.00	23.0	66.7	113	164	219
Solar Buildings	0.30	7.45	22.9	42.7	66.0	92.0
Photovoltaics	3.70	15.6	43.8	70.0	98.0	127
Biopower[2]	3.55	12.2	21.5	30.3	40.2	50.0
Wind	59.0	157	655	1,115	1,610	2,105
Geothermal	4.25	132	283	425	580	735
Distributed Energy and Electric Reliability	177	294	550	775	1,045	1,315
Annual Energy Cost Savings (billions of dollars/year)						
Total Solar Program	10.0	52.7	176	322	494	696
Solar Buildings	0.75	17.1	60.5	122	199	294
Photovoltaics	9.20	35.7	116	200	296	403
Biopower	-1.65	-13.9	-18.1	-14.8	-8.05	5.15
Wind	146	359	1,725	3,180	4,840	6,695
Geothermal	10.6	301	745	1,215	1,745	2,340
Distributed Energy and Electric Reliability	0.50	1.55	3.35	5.25	7.05	8.80
Annual Carbon Displacement (million metric tons of carbon equivalent/year)						
Total Solar Program	0.08	0.48	1.31	2.20	3.20	4.25
Solar Buildings	0.01	0.16	0.46	0.85	1.30	1.80
Photovoltaics	0.07	0.32	0.85	1.35	1.90	2.45
Biopower	0.07	0.25	0.43	0.60	0.80	0.95
Wind	1.10	3.20	13.0	21.7	31.3	40.9
Geothermal	0.08	2.70	5.60	8.25	11.3	14.3
Distributed Energy and Electric Reliability	2.60	7.70	14.4	20.1	27.1	34.1

2) Biopower benefits are cited in terms of Fossil Fuel Energy Displaced because biomass is, itself, a primary energy source.

Table 2. Summary of Benefits Analyses for Energy Supply Technology Programs (cont.)

	2005	2010	2015	2020	2025	2030
Annual SO_x Displacement (millions of metric tons/year)						
Total Solar Program	0.001	0.007	0.019	0.030	0.043	0.057
Solar Buildings	0.000	0.002	0.007	0.011	0.017	0.024
Photovoltaics	0.001	0.005	0.012	0.018	0.026	0.033
Biopower	0.001	0.003	0.004	0.005	0.007	0.009
Wind	0.014	0.049	0.185	0.292	0.421	0.551
Geothermal	0.001	0.041	0.080	0.111	0.152	0.193
Distributed Energy and Electric Reliability	0.050	0.181	0.337	0.469	0.633	0.796
Annual NO_x Displacement (millions of metric tons/year)						
Total Solar Program	0.001	0.004	0.012	0.019	0.028	0.038
Solar Buildings	0.000	0.001	0.004	0.007	0.011	0.016
Photovoltaics	0.001	0.003	0.008	0.012	0.017	0.022
Biopower	0.000	0.002	0.003	0.004	0.005	0.006
Wind	0.010	0.029	0.117	0.192	0.277	0.362
Geothermal	0.001	0.025	0.050	0.073	0.100	0.126
Distributed Energy and Electric Reliability	0.024	0.077	0.142	0.198	0.266	0.335

FY2004 GPRA METRICS
SOLAR PROGRAM
SUB-PROGRAM: SOLAR BUILDINGS

Table 1. Summary of Solar Buildings Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Thousands of systems above Baseline)						
DHW	3.50	202	764	1,526	2,365	3,277
Pool Heating	3.50	40.9	93	159	243	350
Total (may not add due to rounding)	7.00	243	857	1,685	2,608	3,627
Annual Benefits						
Energy Displaced (TBtu)	0.30	7.45	22.9	42.7	66.0	92.0
Energy Cost Savings (millions of 2000 $)	0.75	17.1	60.5	122	199	294
Carbon Displaced (MMCTE)	0.01	0.16	0.46	0.85	1.30	1.80

Market Segments

The solar buildings program includes technologies for solar domestic hot water (SDHW) and solar pool heating (SPH) in residential and commercial buildings. According to EIA data,[1] SPH is the largest end use for solar thermal collectors, representing 95% of the total square feet shipped in 1999. SDHW accounted for nearly all the rest of the market, with only 0.5% for other uses such as space heating. The residential market accounts for more than 90% of each of these end uses. The FY2004 GPRA projections differ from those of FY2003 by including only market quantities and impacts due to DOE programs; specifically, they include only the low-cost polymer solar domestic water heater and the solar pool heater produced in colors other than black to allow wider architectural acceptance. Conventional SDHW and black SPH systems are counted in the baseline. As discussed below, the SDHW is assumed to compete with electric water heating, and the SPH competes with natural gas.

Princeton Energy Resources International (PERI) performed this exogenous model with the resulting penetration reported to OnLocation for inclusion in the NEMS baseline (AEO02) and program (GPRA-NEMS04) runs. OnLocation reduced the results of exogenous models for all programs by 30% across the board as a way of conservatively accounting for likely economic interactions within markets that often cannot be specifically identified without fuller modeling. The unit penetrations reported in Table 1, and the resulting benefits, represent this 30% reduction from the PERI modeled values, which are presented in the remainder of this section.

System Definition and Economics

Solar Domestic Hot Water

Typical residential SDHW systems have collector area ranging from 40 to 80 square feet, depending on geographic location, and costs ranging from $1,800 to $3,600.[2,3] Other studies show similar costs for conventional solar systems, although thermosiphon or integral collector storage (ICS) systems are available for about half that cost in package units with perhaps 20 square feet or less of collector area. The SWAP program in Florida recently installed 24 to 32 square foot direct pumped or ICS systems in low-income homes for $1400 to $1750.[4,5] A detailed analysis of a "traditional" ICS system found a total installed cost of $2800.[6] Note that 80% of solar collector sales (by square feet) went to five states: Florida (44%), California (25%), Arizona (5%), Hawaii (3%), and Nevada (3%).[7] Because most installations are in warmer climates, for this GPRA analysis it is reasonable to assume a cost of $3000 for an average SDHW system using 50 square feet of conventional collector technology.

The analysis assumes the introduction in 2005 of a low-cost polymer collector, which the Solar Buildings Program began developing in 1998 and which is now in prototype testing by two manufacturers. Because this is a storage-type collector, applications would be in milder climates. Existing flat-plate collectors cost about $17 per square foot[8], or about $42 per square foot after manufacturer profit and markups by the distributor and dealer/contractor, and the storage tank and other equipment add an additional $1200 or more.[9] The goal of the DOE program is to reduce the hardware and installation cost by half, using a lower-cost collector and storage tank and simpler installation techniques. Excluding marketing costs, it is estimated that the new system could be sold for $1000. Marketing for the conventional system, sold on an individual basis, is estimated at $800.[6] If the new system could be sold on a mass basis to builders, the marketing cost could be reduced greatly, by perhaps half for the overall market, giving a total cost of $1500 per unit, ranging down to $1000 for large purchases by builders.

For this GPRA analysis, the energy saved by the SDHW system is assumed to be 2,752 kWh per year. Because the warmer areas of the country have lower hot water use per capita and warmer supply water temperature, the actual water-heating load across the country is not uniform. This number corresponds to the national-average site electricity savings calculated by ADL, averaging the cases of high and medium water draw.[10] The ADL analysis was based on simulation model runs for five cities corresponding to the five DOE climate zones, although their method for determining the national average was not disclosed. A recent report by Antares, using data apparently based on the experience of the Sacramento Municipal Utility District, assumes an energy savings of 2,544 kWh per year, 8% lower than that used here.[11]

The solar fraction of an SDHW system is the percentage of water heating energy supplied by solar energy. For a typical SDHW system, the solar fraction is 60%, with the remaining 40% supplied by an auxiliary system, usually an electric heater. System cost decreases if the solar fraction drops below 50% and increases greatly if it is pushed to 80% or higher. The energy savings of 2,752 kWh corresponds to the 60% solar energy supplied by an SDHW system in a household with an average water heating load of 4,583 kWh, typical of a moderate U.S. climate.

Based on this annual energy savings and a residential electricity cost of $0.083/kWh in 2000 (AEO 2002, Table A3), the energy cost savings is $228 per year, giving a simple payback of 13 years for a $3000 current system. However, including an O&M cost for the solar system of $30 annually (based on maintenance once each three years)[12] raises the simple payback to 15 years, a number approaching the system lifetime of 15-30 years. The payback period decreases, however, in states of high electricity cost; for example, above $0.12/kWh (as in much of California or in Hawaii[13]) the payback is less than 10 years, with O&M included. For the polymer system, assuming an installed cost of $1400 per unit, the payback is cut in half, from 15 to 7.5 years, or only 5 years if marketing costs are minimal due to mass purchase.

In comparison with a gas water heater of 60% efficiency, the annual energy savings is $120 at a gas price of $7.64/MMBtu (AEO 2002, Table A3), making the payback greater than 30 years for the current SDHW system. Accordingly, the SDHW is not expected to compete well with natural gas. However, as Antares points out, recent rates of large California utilities are in the range of $16/MMBtu,[11] bringing the payback down to 14 years for a current system and similarly reduced for the polymer SDHW, comparable to the electric case. Nevertheless, in this GPRA analysis, which is based on EIA national energy price projections, only displacement of electric water heaters by SDHW is considered.

Solar Pool Heating

The SPH system consists of an unglazed solar collector, usually plastic. Water is circulated using the pool's existing pump, and the pool provides its own thermal storage. A "rule of thumb" is that the area of an SPH collector area must equal about 50 to 100% of the pool area to provide all the pool water heating requirements, and using a pool cover will reduce the SPH area required, so it is reasonable to assume an average of 75%.[14] For the average residential pool size of 576 square feet, as quoted by DOE's Reduce Swimming Pool Energy Costs (RSPEC) program, the required collector size is 432 square feet, the number used in the FY2003 and earlier GPRA analyses. However, the Solar Energy Industries Association (SEIA) states that the average SPH is 300 square feet, which will be used here.[15]

The present analysis assumes a typical residential SPH system cost of $3500, or just under $12 per square foot, based on SEIA data.[15] The FY2003 and earlier GPRA analyses assumed $4000. Note that according to EIA, the average price of the collector alone in 1999 was $2.08 per square foot, presumably wholesale.[8] This would imply that the final cost, including dealer mark-up and installation, is more than five times the collector price reported by EIA.

A typical SPH lifetime is 10 to 15 years[14] for a plastic or rubber collector, with the main problem being degradation by ultraviolet light. Because the system is so simple, there is little or no maintenance beyond that normally given to the pool's circulating system. Accordingly, this analysis assumes zero O&M costs for the SPH.[16]

Energy performance certifications of unglazed solar pool heating panels indicate that they produce an average of 1000 Btu per square foot per day, according to the Florida Solar Energy Center and the Solar Rating and Certification Corporation.[15,17] Assuming, as does SEIA, a very conservative use of five months per year, the 300 square foot SPH produces 150,0000 Btu/ft^2/year, or a total of 45 MMBtu/yr of thermal energy.

The energy displacement achieved was checked by estimating the solar resource available in a highly favorable location, Miami in this analysis. In that location, a latitude tilt collector receives 177 kWh/ft^2 annually of solar insolation, which is equivalent to 604,278 Btu/ft^2 annually. For six months of operation per year (during shoulder months), it was assumed that the solar insolation was 65% of the total annual. Combining this 65% factor with an annual average efficiency of 70%, one calculates a pool heating demand displacement of 275,000 Btu/ft^2/yr. This is nearly twice the average estimate above.

This GPRA analysis will use the conservative estimate of 150,000 Btu/ft^2/yr. Assuming that gas is displaced and that the gas burner would average an efficiency of 75%, the solar pool collector is assumed to displace 200,000Btu/ft^2/yr. Finally, with an average collector size of 300 ft^2, the annual displacement of primary energy is estimated to be 60 MMBtu (600 therms) per pool. At a natural gas price of $7.64/MMBtu (AEO 2002, Table A3), this yields a payback of 7.6 years. Note that GPRA analyses for FY2003 and earlier assumed a much larger energy displacement of 1600 therms for a somewhat larger system of 432 ft^2.

In more favorable locations, the payback period would be shorter, about 4 years or less, making the SPH quite attractive. SEIA states that the payback is routinely two to three years. The FEMP program reports that SPH paybacks are frequently 2 to 4 years.[18]

The relatively static nature in prices of residential electricity and natural gas to 2030, to $0.0774/kWh and $7.22/MMBtu, respectively, will keep paybacks in this same range for future installations. However, local price increases will reduce the payback period.

The DOE program will develop SPH collector material by 2005 that can be made in various colors other than black, increasing the potential market by allowing greater architectural choices, while maintaining performance and cost.

This analysis does not consider non-residential pools, for which there are certainly some solar applications. For example, *Solar Today* mentions recent installations in the Bahamas and Mexico.[19] According to EIA[1], only 10% of the low-temperature collector shipments in 1997 went to non-residential markets, so their impact on national energy savings is small. The size of these commercial or municipal systems can be 10,000 square feet or more, raising questions of siting and pipe runs. Indoor pools in the U.S. now commonly use integrated heat pump systems for water heating, dehumidification, and air conditioning.

Installation Scenario

<u>Solar Domestic Hot Water</u>

According to EIA, a total of 400,000 square feet of solar collectors for medium-temperature liquids was shipped in 1999, excluding exports[1]. This corresponds to 6,200 to 10,000 SDHW units of common size (40 to 64 square feet). Based on data from the Solar Energy Industries

Association and assuming 50 square feet per system, the SDHW installations are estimated to be 8,448 units for 1998 and 8,000 units for 1999.[20]

In relative terms, this number is quite low. As ADL[21] points out, the overall target market of electric water heating installations is 4 million annually, of which 1.3 million are in single-family households. The ADL chart, "Proposed program goals are based on realistic market penetrations," goes on to state a target of 25,000 SDHW units for an unspecified year, presumably about 2003. EIA data[22] indicate that in 1983, the peak of the domestic SDHW market, the total square footage of medium-temperature collectors sold domestically was 9 million, corresponding to about 140,000 SDHW units (assuming 64 square feet each) or more. By the late 1980s more than a million units had been installed.[23]

The analysis described here assumes a baseline of 8,000 units per year of conventional SDHW sales. Although this number might be expected to grow somewhat over the years, it is also subject to decrease from competition with the polymer system, so for simplicity it is assumed constant. The polymer SDHW market was estimated by Antares[11] based on both new residential construction and retrofit primarily in 9 southern states, displacing electricity only. The fraction of the potential market taken by the polymer SDHW increases from an initial 4% in 2006 to 25% by 2010 and then a maximum of 50% by 2030. After a rapid start-up, annual growth of sales (annual increase in the number of installations in a given year when compared to the number of systems installed in the prior year) averages nearly 20% per year during 2010 - 2015 and finally declines to 2% per year by 2030. As a result, the annual installation rate follows an S-shaped curve. This GPRA scenario would achieve the ADL target level of 25,000 installations per year around 2007. The annual installations are estimated to rise to 228,000 by 2020 and 269,000 by 2030.

On a cumulative basis, the GPRA scenario reaches 500,000 installations by 2012, a strong contribution by solar thermal systems to the DOE Million Solar Roofs Program target. Cumulative installations exceed one million by 2020 and finally reach 4 million before 2030, or roughly 3-4% of single-family households.

This installation scenario is not directly tied to economics. As discussed above, the simple payback for the SDHW is in the range of 10-13 years. Previous renewable energy analyses for DOE[24] have used market penetration targets based on payback, ranging from 100% for a payback of 1 year or less down to zero penetration for a payback of 20 years or greater. For example, a payback of 3 years corresponds to 89%, 5 years to 66.5%, 7 years to 34%, 10 years to 15%, and 12 years to 9%. This implies that the projected market penetration is not unreasonable. Several programs and policies, none of which are modeled in this GPRA analysis, are likely to increase the market attractiveness of SDHW:

- The Database of State Incentives for Renewable Energy reports that 40 states are providing financial incentives for active solar water heating systems, up from the 30 states reported by EIA for 1996.[25,26] The impact of a tax credit is strong, as shown by the history of prior Federal and state tax credits in stimulating the solar water heating market from the mid-1970s to early 1980s. The Clinton Administration's proposed FY2000 Climate Change Budget originally included a 15% tax credit for rooftop solar systems, with a maximum credit of $1,000 for solar water heating systems placed in service from 2000-2004. In the Bush Administration, pending energy bills in both the Senate and the House include a 15% residential solar energy tax credit for 5 years for solar thermal systems.[27]

- The Energy Efficient Mortgage allows the cost of improvements that reduce the energy bill to be included in the home mortgage, thereby offering a lower interest rate and longer term of repayment that could stimulate the market for SDHW systems on both new and existing homes.

- As a part of utility restructuring and regulatory changes, System Benefit Charges or Renewable Portfolio Standards may be used to promote energy efficiency and renewable energy technologies, including solar water heating, although it is unclear what form these programs might take. On the other hand, to the extent that utility restructuring reduces electricity rates, it makes SDHW less attractive.

Solar Pool Heating

RSPEC data indicate that there are 5.6 million residential pools in the U.S., of which half are assumed to be heated. The National Spa and Pool Institute (NSPI) reports 3.6 million in-ground residential pools. NSPI also reports annual sales of 172,000 new in-ground pools in 1998, up from 120,000 in 1994, or about 5% of the existing stock. In-ground pools are more likely to be heated than aboveground pools. These two sources, taken together, suggest that there are some 2 million heated residential pools in the U.S.

The *Solar Today* and *Home Energy* articles both state that as of the late 1990s there were 300,000 solar pool heaters installed in the U.S. According to both NSPI and EIA[1], 8.1 million square feet of pool collectors were sold in 1999, up from 7.2 million square feet in 1998. After subtracting exports and assuming an average system size of 300 square feet, this corresponds to 25,480 SPH systems in 1999, compared with 23,174 units for 1998. Based on Solar Energy Industries Association data, the installations for 2001 are estimated to be 33,000 units, or about one-fifth of the 180,000 pool heating systems sold annually.[15] This amounts to less than 2% of the total potential market on an annual basis, or about 20% of the annual new pool sales, suggesting that the SPH market is established but far from saturated. Data for the First Quarter 2002 showed a strong increase, indicating that for the preceding 12 months sales were nearly 35,000 units.[28]

As discussed above, simple paybacks for SPH systems are often four years or less. Therefore, it is reasonable to expect a high level of market penetration. From the method used in previous renewable energy analyses and mentioned above, market adoption rates could be in the range of 75% or higher.

The SPH baseline assumes that installations have a flat 5% escalation rate (compared to prior year levels), comparable to the current growth rate in number of pools. This is a conservative estimate, given that for the last 3 years growth has been an average of 10-15% annually. Starting from the annual installation rate of 38,000 in 2004, this leads to an annual installation level of

83,000 in 2020 and 135,000 in 2030. Cumulative installations from 2004 grow to 0.3 million in 2010, 1.0 million in 2020, and 2.1 million in 2030.

The DOE program expands the market from this baseline by developing SPH collectors in colors other than black. Some 42 million Americans now live in community associations, which have increased from 10,000 in 1970 to over 200,000 today. A 2000 survey of 13 solar contractors in Arizona, California, and Florida installing 3,800 SPH systems per year, 65% of which are in areas subject to community association restrictions, found that architectural controls by these associations often limit the use of roof-top solar collectors.[29] Greater choice of color would offer a better chance of approval. Assuming that half of the potential SPH market nationwide is in such areas and that half of those could be approved with a color choice, then the impact of the DOE program is to add about 25% to annual installations.

Accordingly, the DOE program portion of the total SPH market is assumed to start from the annual installation rate of 5,000 in 2005 and grow to an annual installation level of 21,000 in 2020 and 34,000 in 2030. Cumulative installations grow to 0.06 million in 2010, 0.2 million in 2020, and 0.5 million in 2030.

Benefits

For purposes of this analysis, SDHW displaces electricity and SPH displaces natural gas. Based on the projections of SDHW and SPH installations from PERI, reduced by 30% by OnLocation, the primary energy, emissions, cost, and fuel displaced are calculated using the assumptions stated in the *GPRA Data Call: Fiscal Year 2004* (Appendix D). Table 2 shows the results of this analysis.

Table 2. Solar Program Benefits from the Water and Pool Heating Program

	2005	2010	2015	2020	2025	2030
DHW (thousands of units)	3.50	202	764	1,526	2,365	3,277
Pool Heating (thousands of units)	3.50	40.9	93	159	243	350
Energy Cost Savings (millions of 2000 $)	0.75	17.1	60.5	122	199	294
Carbon Emissions Displaced (MMTCE/year)	0.01	0.16	0.46	0.85	1.30	1.80
SO_2 Displaced (MMTCE/year)	0.000	0.002	0.007	0.011	0.017	0.024
NO_x Displaced (MMTCE/year)	0.000	0.001	0.004	0.007	0.011	0.016
Primary Energy Displaced (trillion Btu/year)	0.30	7.45	22.9	42.7	66.0	92.0
Direct Electricity Displaced (billion kWh/year)	0.01	0.55	2.10	4.20	6.50	9.00
Natural Gas Displaced (billion cubic ft/yr)	0.21	2.40	5.45	9.35	14.3	20.7

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FY2004 GPRA METRICS
SOLAR PROGRAM
SUB-PROGRAM: PHOTOVOLTAICS

Table 1. Summary of Photovoltaic Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed above Baseline)						
Least Cost	0.11	0.39	0.50	0.50	0.50	0.50
Green	0.07	0.07	0.23	0.39	0.48	0.60
Million Solar Roofs Initiative	0.02	0.50	2.25	4.10	6.00	7.90
Total (may not add due to rounding)	0.20	0.95	2.95	5.00	7.00	9.00
Annual Benefits						
Energy Displaced (TBtu)	3.70	15.6	43.8	70.0	98.0	127
Energy Cost Savings (millions of 2000 $)	9.20	35.7	116	200	296	403
Carbon Displaced (MMCTE)	0.07	0.32	0.85	1.35	1.90	2.45
Technology Indicators[1]						
Cost ($/kW)	2,930	2,150	2,055	1,615		
Capacity Factor (%)	20.8	20.7	20.7	20.7		
Levelized Cost of Energy (cents/kWh in constant 1997$)	20.4	12.8	12.0	9.55		
1) Based on weighting of Rooftop, Central Station Flat Plate and Central Station Concentrator technologies. *Renewable Energy Technology Characterization* data used for NEMS analysis (this report is currently being updated and the values may change).						

Market Segments

In FY 2004 analysis, the photovoltaic (PV) program is expected to penetrate the market through three market segments: the green power market, the least cost power market, and the recently completed Million Solar Roofs (MSR) initiative.

- Green Power - PV has an important role to play in the future green power market. However, at present, because it is significantly more expensive to install than several other green power options, few utilities or energy service providers are likely to choose PV as a way of meeting customer demand for green power. The GPMM reflects this fact by predicting very little penetration by PV in the green power market. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101). The MSR projections, described below, have been added to the results of the GPMM for inclusion in NEMS. Also, there is an additional 250 MW of central station PV "floor" capacity that is "assumed by EIA to be installed for reasons in addition to least-cost electricity supply" between 2001 and 2020. This "floor" capacity addition is prorated for 2004 to 2020 and subtracted from the GPMM and MSR numbers, as the "floor" capacity is viewed as EIA's attempt to account for these other penetration pathways. This final result was then "hard-wired" into NEMS by OnLocation. This analysis does not reflect the additional demand consumers may have for solar energy because it provides increased reliability of service, an emergency source of power, and/or an improvement in load management capabilities. As a result, the benefits reported here understate the likely demand for solar energy.

- Least Cost Power - This segment is unlikely to provide much market opportunity for PV due to the high COEs projected for the foreseeable future. To develop this estimate, NEMS was run using a composite cost and performance trajectory, reflecting the lowest COE in a given period, taken from the *Renewable Energy Technology Characterizations.* The maximum share for intermittent generation and the short-term cost multipliers that indicate how quickly the industry can increase without cost penalties are modified based on analysis undertaken by the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, and Princeton the Energy Resources International.

- Million Solar Roofs Initiative - The Million Solar Roofs initiative, which is scheduled to end in FY 2003, targeted the application of this technology to compete with retail electricity prices, not the very low competitive grid prices. The realization of MSR goals for PV, 600,000 systems installed by 2010, form the basis for the power penetration projected for MSR that are added to the GPMM projections to calculate FY 2004 benefits. Table 2 contains the MSR projections. Projections beyond 2010 assume declining annual growth rates, as would be expected to occur after the end of a major initiative.

Table 2. Million Solar Roofs Program Capacity Projections

	Annual Growth Rate (% above prior year)	Incremental Annual Capacity (MW)	Cumulative Capacity above 2003 baseline (MW)
2000	20%	25	-
2001	21%	30	-
2002	22%	37	-
2003	23%	45	-
2004	24%	56	56
2005	25%	70	127
2007	26%	89	215
2007	27%	113	328
2008	28%	144	472
2009	29%	186	658
2010	30%	242	900
2011	20%	290	1,190
2012	15%	334	1,523
2013	10%	367	1,890
2014	5%	385	2,275
2015	0%	385	2,660
2016	0%	385	3,046
2017	0%	385	3,431
2018	0%	385	3,816
2019	0%	385	4,201
2020	0%	385	4,586

Benefits

- Primary Energy Displaced — Photovoltaics displace conventional electricity on a kWh for kWh basis. The lower capacity factor of photovoltaics does mean, however, that the energy production of a GW of PV is not equivalent to the output of the same capacity of conventional coal capacity. In calculating energy displacement an average grid heat rate is assumed according to the *GPRA Data Call: Fiscal Year 2004*, declining over time by about 25% from 10,713 Btu/kWh.

- Energy Cost Savings — Energy cost savings are derived from energy displacement and average costs of producing electricity according to the *GPRA Data Call: Fiscal Year 2004* were used.

- Carbon Displacement — PV systems displace the carbon that would have been emitted by conventional power plants in producing the electricity. Average grid carbon emission factors according to the *GPRA Data Call: Fiscal Year 2004* are used and declining grid heat rates work again to lower the carbon emissions factor.

FY2004 GPRA METRICS
BIOMASS POWER

Table 1. Summary of Biopower Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed above Baseline)						
Least Cost	0.00	0.00	0.02	0.11	0.26	0.41
Green	0.05	0.19	0.35	0.44	0.47	0.49
Other Biopower Initiatives	0.00	0.00	0.00	0.00	0.00	0.00
Total (may not add due to rounding)	0.05	0.19	0.37	0.55	0.73	0.90
Annual Benefits						
Fossil Fuel Energy Displaced[1] (TBtu)	3.55	12.2	21.5	30.3	40.2	50.0
Energy Cost Savings (millions of 2000 $)	-1.65	-13.9	-18.1	-14.8	-8.05	5.15
Carbon Displaced (MMCTE)	0.07	0.25	0.43	0.60	0.80	0.95
1) Biopower benefits are cited in terms of Fossil Fuel Energy Displaced because biomass has energy content associated with it.						
Technology Indicators[2]						
Cost ($/kW)	1,600	1,420	1,315	1,215		
Capacity Factor (%)	80	80	80	80		
Levelized Cost of Energy (cents/kWh in constant 1997$)	6.7	6.4	6.0	5.5		
2) Based on weighting of Gasification and Direct-fired technologies. *Renewable Energy Technology Characterization* data used for NEMS analysis. Levelized COE includes feedstock cost of $2.50/GJ at a heat rate of 9730 kJ/kWh in 2005 and 2010 and of 8760 kJ/kWh in 2015 and 2020.						

Market Segments

Biopower systems are expected to penetrate in two market segments: the green power market and the least cost power market. This expectation is due largely to biopower's competitive cost of energy.

- Green Power - In the GPMM, gasification and direct-fired technologies were considered. Gasification is an emerging technology that is expected to penetrate modestly in the Green Power market segment. Direct-fired biopower is a well-established technology expected to be used primarily in cogeneration applications at industrial locations, which are modeled under the DEER program analysis, but also expects some penetration through the green power market. Because biomass-generated electricity is so competitive economically and the resource widely available, it is projected to be installed as a green power option in every region of the country. Due to the revisions in the assumptions of sectoral energy consumption and prices, the estimates of green power capacity additions have been lowered for all technologies, when compared to last year's results. The cost and performance data in the *Renewable Energy Technology Characterizations* were used for both technologies. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101).

- Least Cost Power - Gasification is the only technology modeled in NEMS, representing the most likely technology configuration to be installed in future utility-scale biopower systems. Project contingency factors in NEMS have been set to zero (from their default value of 7%).

Benefits are calculated assuming that the gasification technology replaces a natural gas-fired turbine and the direct-fired technology displaces a coal boiler. Industrial biomass cogeneration applications are accounted for under the DEER program, and the biopower program is not given any credit for this capacity. The results of the analyses and key technology indicators are shown in Table 1. The results of the GPRA 2004 analysis have decreased in comparison to the GPRA 2003 reported figures.

FY2004 GPRA METRICS
WIND

Table 1. Summary of Wind Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed above Baseline)						
Least Cost	0.80	2.05	14.8	29.2	43.8	58.3
Green	0.70	2.60	4.35	4.60	4.70	4.95
Distributed	Included in green power					
Total (may not add due to rounding)	1.50	4.65	19.2	33.8	48.5	63.0
Annual Benefits						
Energy Displaced (TBtu)	59.0	157	655	1,115	1,610	2,105
Energy Cost Savings (millions of 2000 $)	146	359	1,725	3,180	4,840	6,695
Carbon Displaced (MMCTE)	1.10	3.20	13.0	21.7	31.3	40.9
Technology Indicators[1]						
Cost ($/kW)	900	835	825	805		
Capacity Factor (%)	42.0	48.1	48.7	50.5		
Levelized Cost of Energy (cents/kWh in constant 1997$)	3.0	2.6	2.6	2.5		
1) *Technology Indicators* data represents a weighted average of new wind turbine characteristics for Class 4 (5.8 m/s average wind speeds) and Class 6 (6.7 m/s) sites, as defined by program planning documents for the Low Wind Speed Turbine project. Weighting changes from 20/80 for class 4/class 6 in 2004 to 75/25 in 2030.						

Note: The capacity, generation and benefits reported in the FY2004 Budget Submission documentation for this program include both wind and hydropower estimates. However, the results presented in this report include only the amount of capacity projected to be installed for wind technologies. Hydropower capacity and generation additions have been excluded from this report, and as such, the values shown here differ from those reported in the FY2004 Budget Submission documentation.

Note: The program's hydropower technology goal of reducing fish mortality associated with hydropower production is largely intended to improve the potential for relicensing of existing facilities, so that this existing capacity is not lost. As such, this goal is effectively incorporated into the NEMS-GPRA04 program case as relicensed capacity: the AEO 2002 Reference Case assumes relatively constant hydroelectric capacity, which requires essentially all existing hydroelectric facilities to be successfully relicensed. Based on analysis undertaken for the Idaho National Engineering Laboratory, the Baseline is revised to remove 1.0 GW and 5 BkWh of hydroelectric power by 2007, increasing to 1.5 GW and 7 BkWh by 2020 to reflect the levels of expected loss of capacity due to concerns related to fish-kill. This hydropower is then re-introduced in the program case.

Market Segments

Wind technologies are expected to be installed in two market segments:

- Green Power - Wind is one of the main competitors in the green power market segment. This market segment and the model used to analyze it are described in Appendix C. Wind, as one of the lowest-cost renewable technologies, competes successfully with the other technologies and thus captures about 63% (40% when MSR and floor capacity is included) of the green market in 2020. There are already several examples of wind energy being installed to meet the demands for green power. The GPMM is regional and wind penetrated every region extensively, except for the South Atlantic and East South Central regions, where wind is excluded from the model due to low resource potential.

- Least Cost Power - This segment has traditionally been considered to have the largest potential for market penetration (as measured by rated capacity) for wind energy. This market segment continues to provide the largest portion of projected penetration, accounting for 86% of the projected capacity additions of wind power by 2020. Market penetration estimates were developed using NEMS, which competes wind against all other generators in this segment. The NEMS analyses were performed by OnLocation. Green power estimates were explicitly included in NEMS prior to the least cost runs because NEMS does not yet effectively predict penetration into that segment. The program goals for wind technologies are modeled directly in NEMS-GPRA04 by incorporating the capital costs, operations and maintenance (O&M) cost, and capacity factors consistent with the program's low wind speed technology goal of 3 cents per kWh by 2012 into the model. For both the Baseline and GPRA cases, the maximum share of electricity generation allowed from intermittent sources was raised from the 12 percent used by EIA to 30 percent, based on experience in other countries. Short-term cost multipliers that indicate how quickly the industry can increase production without driving up the production costs are modified as a result of consultation with NREL, LBNL, and PERI, based on worldwide experience. Thus, the expansion of wind energy without cost penalties associated with manufacturing constraints was increased from 50 percent of installed capacity to 100 percent to reflect the fact that the industry is global and has shown the capability to expand rapidly in the last several years. The benefits estimates are conservative because the wind resource curve in the NEMS model involves assumptions that significantly increase the capital cost of developing new wind resources in ways that are inconsistent with market conditions in nations that have already significantly expanded wind production. Finally, the Production Tax Credit is assumed to run through 2003.

FY2004 GPRA METRICS
GEOTHERMAL

Table 1. Summary of Geothermal Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed above Baseline)						
Least Cost	0.00	1.60	3.80	6.05	8.45	10.8
Green	0.05	0.21	0.42	0.60	0.65	0.70
Enhanced Geothermal Systems	0.00	0.00	0.00	0.00	0.00	0.00
Total (may not add due to rounding)	0.05	1.80	4.20	6.65	9.10	11.6
Annual Benefits						
Energy Displaced (TBtu)	4.25	132	283	425	580	735
Energy Cost Savings (millions of 2000 $)	10.6	301	745	1,215	1,745	2,340
Carbon Displaced (MMCTE)	0.08	2.70	5.60	8.25	11.3	14.3
Technology Indicators*						
Cost ($/kW)	1,430	1,215	1,165	1,115		
Capacity Factor (%)	93.0	95.0	95.5	96.0		
Levelized Cost of Energy (cents/kWh in constant 1997$)	2.9	2.4	2.3	2.1		
*Weighted average of Flash and Binary Geothermal technologies, based on capacity projections. Data taken from *Renewable Energy Technology Characterization* report. These are provided for comparative purposes only, since the NEMS analysis of geothermal uses site-specific cost data.						

Market Segments

Geothermal power is expected to penetrate in two market segments: the green power market and the least cost power market. No distributed uses of geothermal were projected, although there is emerging industry interest in such applications, and a new DOE program to explore small-scale modular geothermal plant technology development (<5 MW).

- Green Power - Flash, Binary, and Enhanced Geothermal Systems (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 in those regions, leading to significant penetration in those two regions. Projections for total green market potential are taken from NREL, *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (NREL/TP-620-30101).

- Least Cost Power - NEMS was run to estimate market penetration into the competitive bulk power marketplace for Geothermal Flash technology. The program goals for geothermal technology improvements are modeled directly in NEMS-GPRA04 by incorporating the capital and operation and maintenance (O&M) cost reductions. The model also takes into account site availability and maximum development per site per year for conventional and Enhanced Geothermal Systems (EGS) geothermal capacity. The conventional geothermal characteristics modeled are from the EPRI/DOE *Renewable Energy Technology Characterizations* report, and the EGS characteristics are developed by Princeton Energy Resources International (PERI). The NEMS model represents individual geothermal sites with different characteristics, with the lowest cost sites being developed first. For the GPRA 2004 analysis, OnLocation has eliminated the construction delay between projects (both large and small) at individual sites. NEMS' limits on amounts of capacity that can be built in any single year at one location have been increased to 100 MW from the prior 50 MW limit. OnLocation has also implemented a code change that better represents the mix of high and low resource areas that are represented in NEMS.

FY2004 GPRA METRICS
DISTRIBUTED ENERGY AND ELECTRIC RELIABILITY PROGRAM

Table 1. Summary of Overall Distributed Program Analysis

	2005	2010	2015	2020	2025	2030
Market Penetration Estimate (Cumulative GW installed above Baseline)						
Total	2.30	7.45	16.3	25.0	33.8	42.6
Annual Benefits						
Energy Displaced (TBtu)	117	294	550	775	1,045	1,315
Energy Cost Savings (millions of 2000 $)	0.50	1.55	3.35	5.25	7.05	8.80
Carbon Displaced (MMCTE)	2.60	7.70	14.4	20.1	27.1	34.1

Market Segments

The Distributed Energy and Electric Reliability (DEER) Program sponsors a wide range of research activities, including advanced turbines and microturbines, natural gas engines, PEM fuel cells, thermally activated technologies, and combined heat and power (CHP) among others. Many of the programs formerly reported separately under Electricity Delivery Programs, such as High Temperature Superconductivity (HTS), Renewable Energy Production Incentive (REPI), Transmission reliability, Energy Storage, Distribution and Interconnection, and Distributed Generation, have been incorporated into the new DEER program. As such, the benefits of these programs are reported under the DEER program. DEER benefits are calculated from the CHP capacity and generation additions modeled in NEMS. Additionally, the Hydrogen program does not receive any credit for hydrogen fuel cell penetration expected in the CHP market. This capacity is credited to the DEER program.

Because of the diversity of the program's efforts and the broad array of market opportunities that present themselves to the various DEER technologies, EERE has used a simplified approach to calculating the benefits of the DEER program. That approach is based on the fact that the overwhelmingly largest benefit will come from the installation of combined heat and power (CHP) systems. Therefore, an analysis of the potential of CHP systems in the U.S. market place was undertaken for GPRA 2004. The results of that analysis were used as a surrogate for the total program benefits.

For the GPRA 2004 benefits analysis, EERE used NEMS commercial and industrial sector CHP analysis modules. The NEMS-GPRA04 baseline limits the rate of new technology adoption and the maximum share of DG technologies based on the extent to which future markets are expected to be able to accommodate these technologies. The program goals for development of distributed electricity technologies (microturbines, reciprocating gas engines, and IC engines at 800 kW and 3,000 kW) are modeled directly in NEMS-GPRA04 by incorporating the improved costs, efficiencies, and other attributes in NEMS-GPRA04 for the program case. The portions of the program designed to enhance the ability of electricity markets to absorb and manage DG are modeled by increasing the maximum CHP market share. Because NEMS-GPRA04 cannot model markets for high-temperature superconductivity (HTS) products, the benefits from these products are modeled directly as reductions in transmission and distribution losses for electricity systems, based on estimates by Energetics of kilowatt-hour reductions from HTS generators, transformers, cables, and motors. The portions of the program that reduce market barriers to consumer investment are addressed by adjusting the model's consumer acceptance curves (market adoption rates by payback period) for CHP.

Not all kWh of electricity have equal value to consumers. Market experience suggests that at least a portion of consumers are willing to pay more for electricity that is more reliable, of higher quality, locally controllable, available during emergency, or cleaner. While market information was available to incorporate the impact of "green power" preferences in these benefit estimates, they do not include consumer purchases based on preferences for improved reliability, load management, or power quality advantages of distributed generation. As a result, these benefit estimates are likely based on an underestimate of the demand for these products under baseline market assumptions.

Results

The results of the NEMS CHP analysis are shown in Table 2 for capacity and Table 3 for generation. NEMS projects that 7.45 GW of additional capacity, above revised AEO 2002 baseline, will be installed by 2010. The bulk of those installations, 7.21 GW, are projected to be in the industrial sector. The NEMS analysis for CHP is based on payback calculated from average prices, and is documented by the Energy Information Administration.

A determination of the fuel-use of these technologies was required to calculate the benefits from CHP introduction. Industrial applications are split between natural gas, coal, oil and biomass. Natural gas is by far the most dominant fuel choice, accounting for 69%-81% of total CHP capacity projections in the NEMS-GPRA04 and AEO02 baseline runs, and 100% of the projected benefits (i.e., the difference between these runs). Industrial biomass cogeneration represents about 10% of total CHP capacity, however no additional biomass is projected by the NEMS-GPRA04 run above the revised AEO02 baseline, and therefore biomass cogeneration receives no benefits for capacity additions. The analysis assumes 100% natural gas use for commercial applications.

Table 2. Cumulative CHP Capacity Additions above AEO 2002 baseline for GPRA 2004

Cumulative Capacity Additions (GW)	2005	2010	2015	2020	2025	2030
Industrial- Biopower	0.0	0.0	0.0	0.0	0.0	0.0
Industrial- Natural Gas	2.21	7.21	15.7	23.9	32.1	40.3
Industrial- Coal	0.00	0.00	0.00	0.00	0.00	0.00
Industrial- Oil	0.00	0.00	0.00	0.00	0.00	0.00
Industrial- Total	2.21	7.21	15.7	23.9	32.1	40.3
Commercial- Total	0.10	0.24	0.54	1.14	1.68	2.24
DEER- Total	2.30	7.45	16.3	25.0	33.8	42.6

Table 3. Generation from CHP Capacity Additions above AEO 2002 baseline for GPRA 2004

Cumulative Capacity Additions (GW)	2005	2010	2015	2020	2025	2030
Industrial- Biopower	0.0	0.0	0.0	0.0	0.0	0.0
Industrial- Natural Gas	16.0	52.0	113	172	231	290
Industrial- Coal	0.0	0.0	0.0	0.0	0.0	0.0
Industrial- Oil	0.0	0.0	0.0	0.0	0.0	0.0
Industrial- Total	16.0	52.0	113	172	231	290
Commercial- Total	0.69	1.75	3.87	8.23	12.1	16.1
DEER- Total	16.7	53.8	117	180	243	307

Benefits from the generation displaced from the grid are then calculated using the following procedures. Both industrial and commercial energy balance calculations are performed, as these sectors have different energy efficiencies and prices. The energy consumed on-site with CHP is netted out against the energy that was used on-site prior to the implementation of CHP and the energy supplied in the form of electricity by the grid. The energy content of the displaced electricity is calculated using both electricity generation and end-use consumption heat rates. The latter is used to calculate the net primary energy displacement and cost savings, as this is the amount of energy that is displaced at the site. However, since the emissions displaced are produced not on site, but rather at the point of generation, the energy content of the electricity at generation must be calculated as well to realize the true net emissions savings. Emissions from CHP systems using natural gas are generally low. Benefits of energy cost savings, carbon emissions savings, and are then calculated in accordance with the GPRA FY2004 guidance document.

Appendix A. Market Segmentation

The market segmentation used in the analysis is shown in Figure A1. At the highest level, the market was divided into: 1) Grid-Side Systems -- systems that are on the grid side of the meter, and owned by utilities or other power suppliers; and 2) Customer-Side Systems -- systems installed at customer locations on the customer side of the meter.

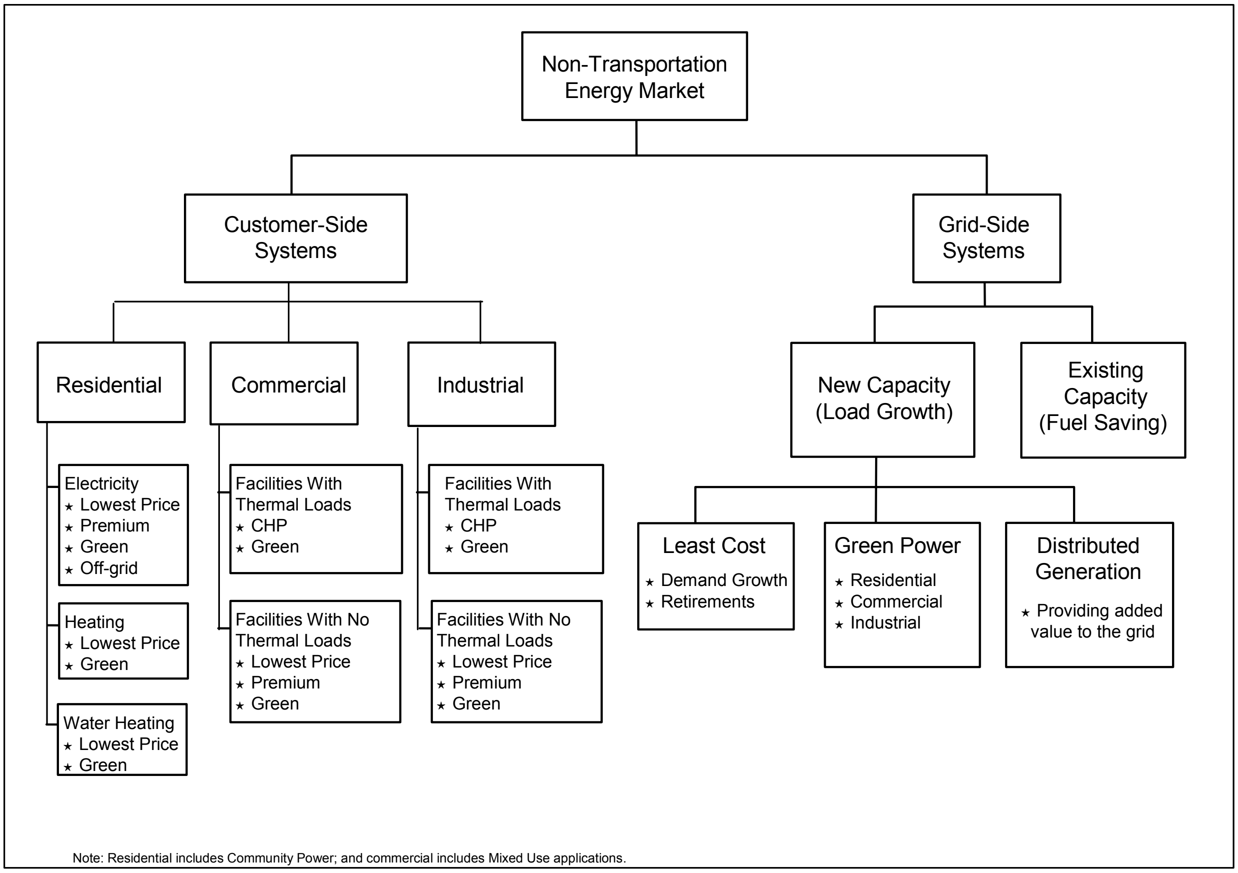

Figure A1. Market Segmentation of EERE Programs.

Grid-Side Systems Segment

The grid-side power segment includes power plants installed at either the transmission system level or at the distribution system level. This segment has traditionally been the realm of the regulated utility and, since 1978, the qualifying facility (QF). For modeling purposes, Grid-Side Power was subdivided into two sub-elements -- new capacity and existing capacity. The former considers capacity additions required to meet demand growth and those required to satisfy capacity needs created by plant retirements. The existing capacity subsegment consider those instances when the costs of generation from either biomass co-firing or intermittent wind and solar plants are less than the variable costs of operating existing plant capacity. This is commonly termed the fuel-saving market.

New capacity requirements have traditionally been met by new plants installed as a result of utility planning processes. As electricity markets are restructured, new business arrangements for satisfying this demand will emerge, but this segment will continue to represent the bulk of the capacity and generation supplied to the grid. (In the evolving restructured market, "merchant" power plants will also be constructed that compete with less-efficient, more-costly existing capacity. The analysis assumed that merchant renewable plants will be few in number.) This least cost subsegment could, in principle, be satisfied by capacity installed at either transmission system level voltages or at distributed system voltages. The former will typically be larger systems (central station) and the latter will be smaller systems (dispersed throughout the distribution system). The analysis characterized the costs and performance of both large and small plant sizes and allowed them to compete as appropriate for new capacity requirements. It must be emphasized that in this subsegment the distribution-level systems are installed solely for their capacity and generation value. No additional benefits to the utility system are considered. Plants that offer such "distributed benefits" are explicitly included in the Distributed Generation subsegment (see discussion later).

Green Power is a term that describes the public's apparent interest in renewable generation as a responsible alternative to conventional energy supply. Customers can acquire *Green Power* either by purchasing it from a supplier, or by installing their own system. The market segmentation reflects both of these options. (Note -- the customer-side green subsegment, shown in Figure A1, was explored for photovoltaics.) The *Green Power* subsegment of the Grid-Side Power segment is an evolving market that the analysis examined explicitly. It included two closely related marketing mechanisms for offering end-users the opportunity to purchase power that is generated by environmentally responsible means. *Green Pricing* is a mechanism by which regulated electric utilities have an approved tariff under which their customers can chose to pay additional monies to ensure that green electricity will be provided by their utility. However, more generally under a deregulated utility supply system, *Green Marketing* programs will include a variety of opportunities through which customers pay a premium to ensure that they are "buying" electricity from green sources.

The *Distributed Generation* subsegment of the Grid-Side Systems segment is also a specialized market. The Distributed Generation portion of the analysis accounted for those site-specific instances where small-scale generating systems or storage systems provide cost-saving benefits to the grid that go beyond pure capacity and generation values. These system benefits are often described as being valuable in supporting weak elements of the distribution system, or as helping alleviate pressures on the distribution system due to rapid load growth on parts of the system. Because this subsegment is just now developing, no installations which are directly attributable to distribution systems were projected.

<u>Customer-Side Systems Segment</u>

The Customer-Side Systems segment was analyzed in three sub-segments: residential, commercial, and industrial, including cogeneration.

Elements of the residential segment include: 1) systems that are owned because they are less-expensive than purchased alternatives (the lowest price element); 2) systems that offer added value to the owner beyond the basic commodity value of electricity, e.g., a desire to have reliable power independent of grid supply -- this value-added element could also have a green component (the value-added element); 3) systems that are green and are purchased for that reason, despite the fact that they are more expensive (the green element); and 4) systems that meet off-grid needs where conventional supplies are either unavailable or prohibitively expensive (the off-grid element).

The commercial and industrial subsegments mirror the residential, although there may be fewer opportunities for the off-grid market element. Cogeneration is defined as a separate element in the industrial subsegment because it is analyzed as a distinct market and was modeled in the National Energy Modeling System (NEMS) Industrial Demand Module and credited to the DEER program.

Appendix B. Overview of Modeling Framework

Table B1 shows the suite of models and analytical tools that EERE used for the analysis. The four Renewable Energy Technology Programs were analyzed using NEMS and the Green Power Market Model. The Solar Buildings program used an exogenous model, prepared by Princeton Energy Resources International. Customer-side Photovoltaics penetration, under the Million Solar Roofs program, was estimated using an exogenous model. The DEER program was modeled in NEMS alone, using the CHP capacity and generation additions as the basis for DEER benefits.

Table B1. Overview of EERE Analysis Approach

EERE Program Element	**NEMS**	**Green Power Market Model**	**Exogenous Models**
Solar Buildings			
Photovoltaics			
Biomass			
Wind			
Geothermal			
Distributed Energy and Electric Reliability			

Appendix C. Green Power Market Model

Introduction

The Green Power Market Model (GPMM or the model) identifies and analyzes the potential generating capacity additions for electricity production that will result from "green power" (either green marketing or pricing) programs, which are not captured in the "least-cost" analyses performed by the National Energy Modeling System (NEMS). Princeton Energy Resources International, LLC (PERI) originally constructed the GPMM in August and September 2000, as a sub-module, with the results hard wired into NEMS as planned capacity. This year's model, based in Microsoft Excel 97, is consistent with efforts from last year, with several changes documented herein. Several significant changes were incorporated last year that were not changed for this year's analysis, including a more detailed and regionalized set of assumptions for electricity market restructuring. These assumptions come from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy*, a recent report by Blair Swezey et al. completed for the National Renewable Energy Laboratory (NREL). The assumptions include the dates for initiation of market restructuring as well as the assumed green power penetration rates, a change in the time periods tracked in the analysis, and a new method for calculating funds from program participants.

Green technologies are marketed as energy production in a cleaner, safer, and renewable fashion. However, the definitions of what constitutes a green technology and how it should be marketed are quite ambiguous in the early deregulation arena. Several agencies and organizations have identified this ambiguity and have offered suggestions. The American Wind Energy Association's (AWEA) *Principles of Green Marketing* was developed in an "effort to foster a credible market in environmentally-preferable electric services… that results in meaningful changes in the electric system as whole." Lawrence Berkeley National Laboratory's (LBNL) *Green Power Certification* report points out the need for creation of certification programs to validate retailers' claims of providing green energy. Several organizations have begun to certify green power marketing claims and sales agreements in areas with competitive access to power available, including the Center for Resource Solutions' (CRS) Green-e program, the Scientific Certification Services' (SCS) Environmentally Preferable Power program, and the Environmental Resource Trust's EcoPower program.

The Green Power Network, a part of the US Department of Energy (DOE), defines both green power and green power marketing on their web page. 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."

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. "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.

The Model

Technologies:

The model projects additional capacity and electricity generated from green technologies for the periods 2004 to 2008 and 2009 to 2010, and then five-year periods to 2030. Sixteen individual technologies, comprising five technology types, were selected as both green and commercially viable for this analysis. The technologies, listed below, can be grouped into categories based on both the availability of power, Dispatchable or Intermittent, and on resource use. These are:

Dispatchable:

1) Biomass:	- Direct-Fired Biomass
	- Biomass Gasification
	- Landfill Gas
2) Geothermal:	- Flash Geothermal
	- Binary Geothermal
	- Hot Dry Rock
3a) Concentrated Solar Power:	- Solar Thermal Trough
	- Solar Thermal Dish- Hybrid
	- Solar Central Receiver

Intermittent:

3b) Concentrated Solar Power	- Solar Central Receiver (Intermittent)
	- Solar Thermal Dish- Stand Alone
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. Generally, the additional capacity needed to maintain stability of power comes in the form of diesel generators or gas turbines, for which the model calculated these additional costs. 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 back-up generation to provide a continuous source of power. Developers are assumed to build the sites in least cost fashion (without back-up) and take the “green” electrons when and from where they are able. The “firm up” costs are now set to zero in the model, which effectively removes the competitive advantage, and therefore the distinction, of dispatchable sources over intermittents.

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 US Census regions as the breakdown, as the availability of regional data for the model often takes this format. Eight regions (South Atlantic and East South Central have been combined) are modeled independently, and then summed to produce national results. 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.

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 thirteen divisions used in NEMS. The NEMS divisions are based on the North American Electric Reliability Council's regions. The names of these regions, and the conversion formulas from the census region breakdown are documented in the model.

The state-by-state restructuring and penetration assumptions taken from the *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy* (the NREL report) are summed across these regions, and are pro-rated based on the loads of the electric market in each state compared to the region as a whole.

Revisions to the FY04 Model:
Several revisions to the FY03 GPMM have been made in the update for FY04. The reporting of years has been changed from 2003-7 and 2008-10 to 2004-8 and 2009-10, with the five-year increments thereafter to 2030 remaining consistent. New technology characterizations for wind, class 4 and 6 data averaged, and CSP, trough and power tower data, were taken from program revisions to the *Renewable Energy Technology Characterizations, EPRI-TR109496* report (TC report). All other technologies remained consistent in using 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.

Most of the major assumptions of the GPMM remained unchanged. The model still incorporates extensive revisions to the assumptions included for the FY03 model. Many of these assumptions, including the rates at which electricity markets restructure, and the participation levels of customers in these new markets were taken from *Growing the Green Power Market: Forecasting the Impacts of Customer Demand for Renewable Energy, NREL/TP-620-30101* (the NREL report).

The regional economic sectors' energy consumption and prices were updated according to the new Energy Information Administration's (EIA) assumptions for the *Annual Energy Outlook 2002, DOE/EIA-0383(2002)* (AEO2002). The regional energy consumption and prices were taken from tables 1-20 of AEO2002 Supplemental Data Tables. Tables 1-3, on the following pages, show the differences in regional energy consumption and prices for the residential, commercial and industrial sectors between the FY03 and the FY04 models.

Table 1. Residential Energy Consumption and Prices by Census Region.

Census Region	Model Year	1999/2000 Residential Energy Consumption (Quads)	2020 Residential Energy Consumption (Quads)	1999/2000 Residential Energy Prices (2000$/MMBtu)	2020 Residential Energy Prices (2000$/MMBtu)
National	FY03	3.91	5.80	23.95	22.50
	FY04	4.07	5.70	24.36	22.55
New England	FY03	0.14	0.20	33.26	29.84
	FY04	0.14	0.19	34.04	30.97
Mid. Atlantic	FY03	0.38	0.50	31.74	28.34
	FY04	0.38	0.49	32.22	29.03
E. N. Central	FY03	0.56	0.82	23.33	20.61
	FY04	0.58	0.83	23.24	20.99
W.N. Central	FY03	0.29	0.40	20.87	20.32
	FY04	0.30	0.41	22.04	20.16
S. Atlantic & E.S. Central	FY03	1.27	1.95	22.00	21.88
	FY04	1.35	1.95	23.29	21.09
W.S. Central	FY03	0.57	0.90	21.10	20.89
	FY04	0.61	0.87	21.87	20.90
Mountain	FY03	0.23	0.38	22.38	22.41
	FY04	0.25	0.39	21.73	22.69
Pacific	FY03	0.46	0.66	25.37	23.65
	FY04	0.46	0.59	25.64	25.49

Table 2. Commercial Energy Consumption and Prices by Census Region.

Census Region	Model Year	1999/2000 Commercial Energy Consumption (Quads)	2020 Commercial Energy Consumption (Quads)	1999/2000 Commercial Energy Prices (2000$/MMBtu)	2020 Commercial Energy Prices (2000$/MMBtu)
National	FY03	3.70	5.61	21.86	18.39
	FY04	3.91	6.12	22.11	20.33
New England	FY03	0.16	0.22	28.23	19.99
	FY04	0.14	0.19	28.55	23.81
Mid. Atlantic	FY03	0.47	0.63	16.78	14.02
	FY04	0.49	0.63	28.25	24.73
E. N. Central	FY03	0.56	0.82	21.15	17.64
	FY04	0.55	0.74	20.68	19.50
W.N. Central	FY03	0.25	0.37	19.24	17.67
	FY04	0.28	0.41	18.11	17.16
S. Atlantic & E.S. Central	FY03	1.06	1.67	19.24	18.00
	FY04	1.11	1.95	20.15	19.07
W.S. Central	FY03	0.46	0.70	18.91	17.72
	FY04	0.49	0.72	19.07	18.52
Mountain	FY03	0.25	0.42	18.54	18.12
	FY04	0.28	0.52	18.77	19.32
Pacific	FY03	0.49	0.79	24.90	18.68
	FY04	0.56	0.95	26.64	23.01

Table 3. Industrial Energy Consumption and Prices by Census Region.

Census Region	Model Year	1999/2000 Industrial Energy Consumption (Quads)	2020 Industrial Energy Consumption (Quads)	1999/2000 Industrial Energy Prices (2000$/MMBtu)	2020 Industrial Energy Prices (2000$/MMBtu)
National	FY03	3.63	4.81	13.29	11.79
	FY04	3.65	4.83	13.50	13.04
New England	FY03	0.09	0.11	22.40	15.15
	FY04	0.09	0.11	22.64	18.15
Mid. Atlantic	FY03	0.30	0.37	20.65	16.34
	FY04	0.29	0.36	17.05	16.88
E. N. Central	FY03	0.77	0.99	12.77	11.71
	FY04	0.78	1.00	13.13	13.44
W.N. Central	FY03	0.27	0.35	12.35	11.11
	FY04	0.29	0.36	12.36	11.36
S. Atlantic & E.S. Central	FY03	0.98	1.30	12.57	11.76
	FY04	1.00	1.31	12.82	12.45
W.S. Central	FY03	0.56	0.76	11.50	11.98
	FY04	0.56	0.77	11.70	12.58
Mountain	FY03	0.24	0.34	12.10	11.29
	FY04	0.24	0.33	11.47	11.69
Pacific	FY03	0.41	0.59	15.11	10.54
	FY04	0.41	0.59	15.70	13.17

As can be seen from Tables 1-3, some notable differences occur in the economic sector demand assumptions in energy consumption and prices. In the residential sector, Table 1, the residential energy consumption for the nation increased 2% in the beginning (1999-2000), from 3.91 to 4.07 Quads, but decreased 4% at the end (2020), from 5.80 to 5.70 Quads, of the analysis period. 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. The national residential energy prices (in 2000$) increased only slightly, 2%, for the beginning of the analysis and did not effectively change for the end of the period. On a regional level for the residential sector, the largest differences were seen in the Pacific region, where energy consumption in 2020 decreased by 11% while prices rose 8% in 2020.

Table 2 shows the commercial sector demand assumptions. The most noted change is increases of 68% and 76%, respectively, of the Middle Atlantic region's commercial energy prices in 1999-2000 and 2020. Other significant changes include a reduction in commercial energy consumption in the New England and East North Central regions, while consumption levels increased in the Mountain and Pacific regions.

Table 3 shows the industrial sector demand assumptions, which remained the most consistent from FY03 to FY04. The current energy prices (1999-2000) for the Middle Atlantic region dropped 17%. On the other hand, future energy prices (2020) increased by 25% and 20%, respectively, for the Pacific and New England regions.

The regional residential household data is used to calculate the size of the potential green power market for the residential sector. This data was updated for the FY04 model from a file sent by John Cymbalski, of the EIA. ("Regional hhs- updated from J Cymbalski 6-5-02.xls") The regional household data generally increased or decreased by only 1% to 2%, with the exception of the Pacific and West South Central regions, which had the largest deviation, increases of 5.3% and 4.9%, respectively, in 2020. Increasing households in a region has the effect of generating a larger potential green electric market and therefore more green revenues, which would increase GPMM capacity builds in that region.

The commercial floorspace and industrial gross output are used to determine the number of commercial and industrial establishments, respectively. Similar to the number of households, the number of establishments, combined with electric market restructuring and participation levels from the NREL report, determines the size of the potential green power markets for the commercial and industrial sectors, and therefore the GPMM capacity builds in each region. National data for commercial floorspace and industrial gross output was taken from Tables 22 and 23 of AEO2002 Supplemental Data Tables. These tables do not provide regional data of commercial floorspace or industrial gross output. Therefore, regional data was calculated on the basis of the national data and the regional percentages of the national total for these inputs in the FY03 model.

In addition to the economic sector demand data assumptions changed, a few other minor changes were made to the model. The regional limit on the amount of landfill gas (LFG) was modified so that only 2/5 of the five-year regional limit of 70 MW was allowed for the two-year period from 2009 to 2010.

PERI included both additions and subtractions to the green capacity values for the Million Solar Roofs (MSR) capacity additions, and EIA "floors" builds, Tables 4-6. The MSR capacity additions, Table 4, are added to the green model numbers in the reporting of the PV-residential green capacity.

Table 4. Million Solar Roofs Initiative Incremental Capacity Additions in GPMM04

Year Period	MSR Capacity Additions (above 2003 Baseline)
2004-2008	472
2009-2010	428
2011-2015	1,761
2016-2020	1,926
2021-2025	1,926
2026-2030	1,926
Total for 2004-2030	8,439

An additional 250 MW of central station PV and 54.5 MW of central station solar thermal "floors" capacity from 2001 to 2020 are "assumed by EIA to be installed for reasons in addition to least-cost electricity supply". These "floors" capacity additions, Table 5, are prorated for 2004 to 2020 and regionally divided.

Table 5. EIA "Floors" Incremental Capacity Additions for PV and Solar Thermal in NEMS

Year Period	EIA PV "Floors" Capacity Additions (above 2003 Baseline)	EIA Solar Thermal "Floors" Capacity Additions (above 2003 Baseline)
2004-2008	62.5	13.6
2009-2010	25.0	5.5
2011-2015	62.5	13.6
2016-2020	62.5	13.6
2021-2025	0.0	0.0
2026-2030	0.0	0.0
Total for 2004-2030	212.5	46.3

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), Table 6. As can be seen in Table 6, all of the Solar Thermal "floors" additions were subtracted from the GPMM04 results. At the same time, only a portion of the PV "floors" additions in the first two time periods were subtracted due to less capacity being built in each of the regions by the GPMM04 then was added by the "floors" capacity.

Table 6. EIA "Floors" Incremental Capacity Additions Subtracted from the GPMM04

Year Period	EIA PV "Floors" Capacity Additions Subtracted from GPMM04 (above 2003 Baseline)	EIA Solar Thermal "Floors" Capacity Additions Subtracted from GPMM04 (above 2003 Baseline)
2004-2008	17.8	13.6
2009-2010	22.6	5.5
2011-2015	62.5	13.6
2016-2020	62.0	13.6
2021-2025	0.0	0.0
2026-2030	0.0	0.0
Total for 2004-2030	164.9	46.3

Results

Comparison of Final Results:

Table 7 and 8 show the final results of the GPMM03 and GPMM04 that were hardwired into the NEMS AL01 and AL02 runs, respectively. However, due to the changes that are detailed in this report, including MSR additions and subtracting out EIA "floors" additions, these tables are not directly comparable. Table 9 shows the results of the GPMM04 without including MSR additions and subtracting out EIA "floors" additions.

Table 10 is then calculated as the difference between Table 7 and Table 9, and shows the changes in the results of the GPMM due to changes in the assumptions, rather than due to changes in the methodologies. As can be seen in Table 10, the total additions are relatively stable, with most of the changes seen between technologies. Wind and CSP see large increases while the other technologies all lose capacity gains. This is due to the revised technology characterization data for wind and solar thermal, lowering the capital costs and cost of energy, and therefore making these choices more attractive in the model.

Table 7. Results of the GPMM03- Cumulative Capacity Additions Relative to 2002 Baseline

	2010	**2020**	**2030**
Biomass (incl. LFG)	388	823	972
Geothermal	261	694	820
CSP	209	609	703
PV	143	668	963
Wind	2,418	4,462	4,842
Total	3,419	7,256	8,299

Table 8. Results of the GPMM04- Cumulative Capacity Additions Relative to 2003 Baseline

	2010	**2020**	**2030**
Biomass (incl. LFG)	287	673	802
Geothermal	209	600	705
CSP*	257	801	970
PV*	968	4,973	9,045
Wind	2,632	4,601	4,948
Total	4,353	11,648	16,470

Table 9. Results of the GPMM04- Cumulative Capacity Additions Relative to 2003 Baseline Without Methodology Changes from the GPMM03.

	2010	**2020**	**2030**
Biomass (incl. LFG)	287	673	802
Geothermal	209	600	705
CSP*	276	847	1,017
PV*	108	551	771
Wind	2,632	4,601	4,948
Total	3,512	7,272	8,242

Table 10. Difference in the Results of the GPMM04 Compared to the GPMM03 Without Methodology Changes from the GPMM03.

	2010	**2020**	**2030**
Biomass (incl. LFG)	-101	-149	-170
Geothermal	-52	-95	-115
CSP	67	238	313
PV	-35	-117	-191
Wind	214	139	106
Total	93	17	-56

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