Appendix D – GPRA07 Solar Energy Technologies Program Documentation

1. Introduction

This appendix provides detailed information on the assumptions and methods employed to estimate the benefits of EERE's Solar Energy Technologies Program. The benefits analysis for the Solar Program utilized both NEMS and MARKAL as the analytical tools for estimating the program's benefits. As will be discussed below, a number of assumptions and structural modifications to the models were made in order to represent the suite of solar technologies funded by the program as accurately as possible—photovoltaics (PVs) and concentrating solar power (CSP). Many of the assumptions used in the FY07 analysis are the same as or similar to those employed in the FY06 analysis; however, two key changes are important to highlight up-front. First, the program case cost targets for photovoltaics included here are considerably more aggressive than the GRPA06 targets. This reflects anticipated changes in FY07 in the solar program's structure and funding as included in the President's Solar America Initiative. Second, the FY07 analysis does not include Solar Hot Water (SHW) technology benefits which were included in the FY06 analysis. This change is based on zeroing out funding for SHW as reflected in the president's proposed in FY07 budget.

The body of this appendix contains two sections. The first discusses the assumptions used to construct the GPRA07 Solar Program baseline scenario. The second discusses the modifications that were made to this baseline to construct the GPRA07 solar program scenario.

2. GPRA07 Solar Program Baseline Assumptions

Several changes from the *AEO2005* Reference Case were incorporated into the GPRA07 Baseline. These changes include the following:

Revising projected PV cost. The residential and commercial PV system characteristics in the *AEO2005* were based on a recent Navigant Consulting report (Navigant 2003). This report lays out a projection of future PV system costs, but does not explicitly distinguish between Federal R&D and private activity effects. However, the projections are very similar to the program's FY06 targets as laid out in its recent draft Multi-Year Program Plan (DOE 2005). Thus, the *AEO2005* targets do appear to include R&D. As such, they are not appropriate for use as a Baseline from which the program's impacts are to be measured. Therefore, an alternative Baseline was developed assuming that private industry would continue to improve first-generation PV (crystalline silicon) technology, but would not invest significantly on its own in second- or third-generation PV (thin-film, etc.) technologies. As shown in **Figure 1**, changes in the program's structure and funding levels are expected to result in accelerated cost reductions through 2015 under the GPRA07 Program case. In constructing the GPRA07 baseline, the following approach was used. Between 2005 and 2015, the costs of PV are assumed to decline more slowly than in the *AEO2005* targets, leading to a five-year lag between the GPRA07 baseline and *AEO2005* targets by 2015. Beyond 2015, the GPRA07 baseline and GPRA07 program numbers are assumed to continue to diverge. This approach captures the notion of technological lock-in (Cowan and Kline 1996).

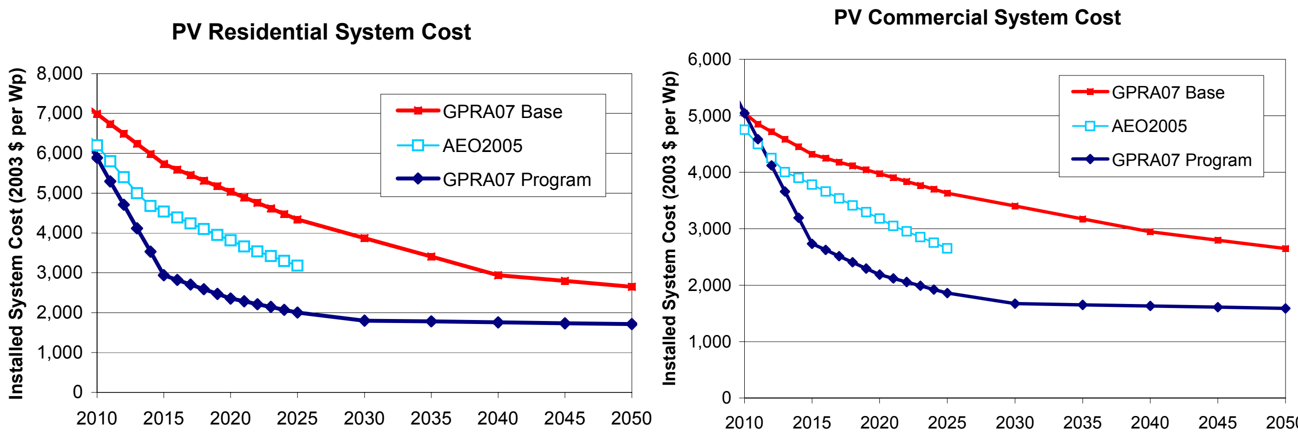

Figure 1. Projected PV System Costs

Increasing the average commercial building system size from 25kW to 100kW. A sample of data from 14 PV systems installed by PowerLight Corporation, between July 1999 and March 2003, reveals that the average commercial system installed by PowerLight during this period was 381kW (**Table 1**).

Table 1. Commercial System Size and Surface-Area Requirements

PowerLight System Installation Location	Date Completed	System Peak Capacity (kW)	PV Surface Area (sq. ft.)	W/sq.ft.
Santa Rita Jail – Alameda County, California	Apr-02	1,180	130,680	9.0
Cypress Semiconductor – San Jose, California	Jul-02	335	26,100	12.8
Fala Direct Marketing – Farmingdale, New York	Nov-02	1,010	102,700	9.8
Fetzer Vineyards – Hopland, California	Jul-99	41	3,750	10.9
Franchise Tax Board – a Sacramento, California	Aug-02	470	50,000	9.4
Greenpoint Manufacturing – Brooklyn, New York	Mar-03	115	11,500	10.0
Mauna Lani Resort – Kohala Coast, Hawaii	Jan-02	528	43,330	12.2
Naval Base – Coronado, California	Sep-02	924	81,470	11.3
Neutrogena Corp. – Los Angeles, California	Aug-01	229	30,154	7.6
Parker Ranch – Kameula, Hawaii	Jan-01	209	20,000	10.5
PSGA/Ortho-McNeil Facility – Pennsylvania	Apr-02	75	17,500	4.3
U.S. Coast Guard – Boston, Massachusetts	Sep-99	37	3,800	9.7
U.S. Postal Service – Marina del Rey, California	Nov-01	127	15,000	8.5
Yosemite National Park - Yosemite, California	Oct-01	47	4,500	10.4
Total		**5,327**	**540,484**	
Average		**381**	**38,606**	**10**

Source: PowerLight Case Study data sheets, Downloaded from www.powerlight.com, 5/21/03.
Note: Some of the locations shown in this table have multiple installations. In these cases, the total installed capacity is shown above, and the most recent installation date is shown in the date-completed column.

The average space required for these systems was 0.1 sq. ft/W., based on a U.S. average commercial building size in 2000 of 14,500 square feet (AEO2003), and assuming a ratio of usable roof space to floor space of 0.7. This ratio of usable roof space to floor space was based on the "architecturally suitable area" in an International Energy Agency (IEA) report, Table 2, examining the potential for integrated photovoltaics in buildings (IEA 2001). Using this approximation, the average commercial building could easily accommodate a 100 kW PV system, i.e., a 0.7*14,500 sq. ft. = 10,100 sq. ft. PV array. Thus, setting the average system size at 100kW is a conservative assumption based on industry trends, as well as the available roof space on a large share (50+%) of the commercial building stock. This is a very conservative assumption because it does not reflect expectations that the efficiency of PV cells will increase; the space requirements for a PV system will decrease; and, as system costs decline, facades and other spaces (such as parking lots) also could be utilized for PV systems.

Increasing the maximum share of commercial buildings with solar access from 30% to 55%. Similar to the preceding ratio of usable roof space to floor space, the share of roof space suitable for PV installations was based on the published IEA report on integrated photovoltaics in buildings (IEA 2001). This report indicates that a reasonable estimate for the share of roof space suitable for PV installations is 55%. This estimate includes shading and other factors that would limit the use of roof space for PV systems (IEA 2001).

Increasing the average residential building system size from 2kW to 4kW. A couple of years ago, a typical residential rooftop PV system was a 2kW system—this is most likely the source for EIA's 2kW system size in the *AEO2005* reference case. However, residential rooftop systems being installed in Japan, Europe, and the United States have been growing larger. For example, the average Japanese rooftop system size in 2002 was 3.7 kW (Ikki 2003) and the average rooftop system size in California in 2004 was 3.6 kW.[1] The average home in the United States has 1,700 square feet of floor space (this is expected to increase in the future). Using data from EIA's residential energy-consumption survey (EIA 1999, Table HC1-2a) one can estimate a floor- to roof-space ratio of 0.7 (based on distribution of one-story, two-story, and three-story single-family homes). This is a conservative estimate—most homes have pitched roofs, which would increase the total available roof space (yet may make a significant portion of the roof oriented away from the sun). If a typical system can accommodate 10 W/sq.ft (as above), then a 4kW system would require roughly 400 square feet of roof space, which is well below the average available space allowing for multiple floors and pitched roofs. Thus, roof space is not a constraint for installing residential rooftop PV systems in the 4kW range. Because the efficiency of PV cells is likely to improve, a trend toward larger systems on rooftops is likely to continue. Thus, based on available roof space and what is happening in the marketplace, setting the average system size at 4kW is a conservative assumption.

Increasing the maximum share of residential buildings with solar access from 30% to 60%. A maximum share of 60% for residential buildings with solar access was used. This estimate accounts for the fact that some homes will not be suitable for PV systems due to shading,

[1] This estimate was based on data from the California Energy Commission's Emerging Renewables Program, downloaded on 1/27/05 from www.energy.ca.gov/renewables/emerging_renewables.html. Data on small PV systems (i.e., with a system size under 10kW) were extracted from the full dataset. It indicated that, during 2004, a total of 15.9 MW of PV was installed in 4,372 small PV systems in California, with an average system size of 3.6kW.

building orientation, roof construction, or other factors. This value was calculated from a combination of single-family homes (70%) and multifamily homes (30%), using a 75%-25% split between single-family and multifamily homes (EIA 2003, Table A4). Thus, the average maximum share was set at 0.7*0.75 + 0.3*0.25 = 0.6.

Including a declining PV buy-down program in California. This baseline is constructed under the assumption that the California renewable energy credit program that provided a PV credit of $4,000/kW in 2003 will continue to be available, but will decline by $400/kW per year. This credit is roughly in-line with the declining subsidy included in the recently past California Solar Initiative. This credit was included for the entire Pacific region. Given that a number of other local credits were not included in the GPRA baseline, applying the California state-level credit to the whole Pacific region is likely to be a reasonable approximation.

Modifying the adoption rate of distributed generation technologies. The modification to the adoption rate was based on information provided by the DER program (**Figure 2**). This applies to PV as well as gas-fired CHP technologies.

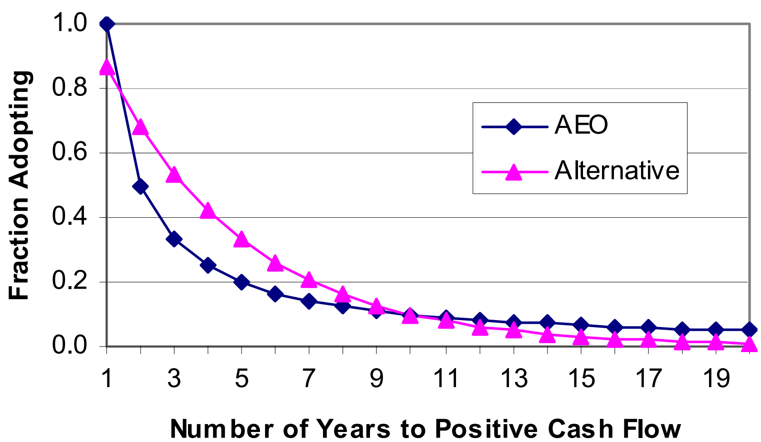

Figure 2. Commercial-Sector DG Adoption Rates

These changes lead to increased adoption of PV systems in the baseline. However, the *AEO2005* assumptions about PV installations through the Million Solar Roofs program were removed, so that there would not be double-counting when these were introduced in the Program Case.

3. GPRA07 Solar Program Scenario Assumptions

Three key sets of assumptions were modified to generate the GPRA07 Solar Program scenario.

Green power additions. Green power additions by region, from Princeton Energy Resources International (PERI), were added back into the Solar Program scenario (**Table 2**). These projections take into account the Baseline assumptions of noneconomic capacity additions. This capacity is added in NEMS-GPRA07 as exogenous additions in residential and commercial buildings.

Table 2. Incremental Green Power PV Capacity Additions (MW)

Incremental Green Power PV Capacity Additions (MW)					
	2007-2010	2011-2015	2016-2020	2021-2025	Total
ECAR	64	183	140	41	428
ERCT	58	167	129	38	392
MAAC	56	159	122	35	372
MAIN	16	47	36	11	110
MAPP	4	12	9	3	28
NY	12	35	27	8	81
NE	16	47	36	10	109
FL	75	214	164	47	500
STV	225	641	491	142	1,500
SPP	61	173	133	40	406
NWPP	11	31	23	7	72
RA	19	54	42	13	128
CNV	0	0	0	1	1
Total	618	1,761	1,350	396	4,125

Technology Characteristics. More aggressive technology targets were used for the range of solar technologies: concentrating solar power (CSP), central PV systems, and distributed PV systems. The CSP technology characteristics were based on the Solar Program's most recent draft Multi-Year Technical Plan (DOE 2005). The PV targets were based on anticipated changes in the Program's structure and funding.

In order to define a consistent set of long-term targets going out to 2050, a multi-lab, multi-technology team was assembled in 2003. This team produced technology cost projections for use in NEMS that are consistent with the Solar Program's Draft Multi-Year Program Plan (DOE 2005) through 2025 and extended the Solar Program's targets to 2050 (for details, see Margolis and Wood 2004). In setting the targets used for PV technology in the GPRA07 analysis, we also drew on the U.S. PV Industry Roadmap (SEIA 2004). Thus the targets shown in **Tables 3 and 4** are consistent with the Program's Draft Multi-Year Program Plan (DOE 2005), Margolis and Wood (2004), and SIEA (2004). It is important to note that beyond 2025, the targets are increasingly uncertain and are likely to be revised as the Solar Program continues to analyze the long-term prospects for technology cost reductions. Note that, on an annual basis, costs are assumed to decline linearly between the years shown in the tables below.

While the technology assumptions for commercial rooftop PV systems are shown above in **Figure 1**, detailed data for PV systems in the three markets modeled is provided in **Table 3**. Although the costs shown below are for specific years, the costs decline annually between the years shown. Note that in both the GPRA baseline and program scenarios, the *AEO2005* Reference Case assumptions for solar insolation and capacity factors were used.

Table 3. PV Systems

	Central Generation		Residential Buildings		Commercial Buildings	
Year	Installed Price (2003$/kW)	O&M (2003$/kW)	Installed Price (2003$/kW)	O&M (2003$/kW)	Installed Price (2003$/kW)	O&M (2003$/kW)
2005	5,500	40	8,500	100	7,000	40
2010	3,700	10	5,600	40	4,800	20
2015	2,100	4	2,800	20	2,600	10
2020	1,680	3	2,240	16	2,080	8
2025	1,428	2.7	1,904	13.6	1,768	7
2030	1,285	2.0	1,714	12.0	1,591	6
2050	1,221	2.0	1,628	12.0	1,512	6

Note: Installed costs do not include the impact of the 10% investment tax credit.

The data for CSP technology shown in **Table 4** are for California. The CSP costs are up to 13% higher in other regions with less solar insolation to account for greater capacity and storage requirements. The annual capacity factors by 2020 range from 49% in MAPP (the Upper Midwest) to 74% in the Southwest. The capacity factors by time period were computed by Sandia analysts to optimize the timing of solar output for each region within the bounds of the storage potential. Note that the *AEO2005* Reference Case assumptions include lower-cost CSP systems, but with significantly less storage and therefore lower electrical output.

The future cost assumptions for CSP technology in the Solar Program scenario are based on a funding level consistent with the FY07 budget request for FY07 and a funding level commensurate with those outlined in the Draft CSP Technology Transition Plan for years beyond FY07 (DOE 2005).

Table 4. Concentrating Solar Power

Year	Installed Price (2003$/kW)	O$M (2003mills/kWh)	Capacity Factor
2010	3,510	7.8	65%
2020	2,462	4.0	72%
2025	2,199	3.6	72%
2030	1,993	3.2	72%
2035	1,879	3.1	72%
2040	1,826	3.0	72%
2050	1,797	2.9	72%

4. Sources

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