Appendix D – GPRA06 Distributed Energy Program Documentation

Program Objective

The major programs modeled for DE include:

Industrial Gas Turbines
Advanced Microturbines
Gas-Fired Reciprocating Engines
Thermally Activated Technologies
Distributed Energy Systems Applications Integration
Cooling Heating and Power Integration
The Technology Base – (Advanced Materials and Sensors is not modeled directly because its benefits are represented in the other programs).

Methodology and Calculations

Because the time horizon of the *Annual Energy Outlook 2004* Reference Case (AEO-4 case) version of the National Energy Modeling System (NEMS) is 2025, and the goals of Distributed Energy (DE) programs are relatively short term, the approach taken in this GPRA cycle is that most of the outputs are captured before that date. However, DE programs are part of a wider effort to transform the power system from its current highly centralized form to a more robust decentralized paradigm, a transformation with a longer time horizon than NEMS-GPRA provides, and are not readily represented in the NEMS-GPRA framework.

Distributed generation (DG) appears in multiple modules (roughly corresponding to subsectors of the full energy sector, i.e. utility, commercial, etc.), which hinders DE program's representation in NEMS-GPRA. Further, only a limited number of technology slots are available to represent a broad array of equipment types, sizes, and configurations. For example, the reciprocating engines in the commercial sector all have combined heat and power (CHP) heating (but not cooling) capability, while those in the utility sector do not, while in some instances, engines without CHP might be attractive in the commercial sector and vice-versa. Proper representation of DE program goals includes an accurate representation of DE's technology-advancement targets, while accounting for the limitations of NEMS. Therefore, in addition to changing input assumptions relative to the AEO-4 version of NEMS, other *fixes* to perceived limitations or omissions are also appropriate in both the base and program cases.

Inputs to Base Case

Expectations of improvements in technologies embedded in the AEO-4 reference case, which presuppose existence of DE programs, need to be eliminated from the base case (referred to as the baseline) for comparisons with achievement of program goals (referred to as the program case). Two full sets of forecast scenarios are actually needed, *with* and *without* DE programs in place; and the AEO-4 case is likely, although not certain, to fall between the two. In the FY 2006

GPRA (GPRA06), the baseline case generally corresponds to a 10-year lag of the program case, though there are exceptions as described below. Estimation of the benefits of the programs is based on a comparison of the *baseline* and *program* scenarios. In this analysis, both scenarios were effectively estimated together as two deviations from the AEO-4 case, so they are presented together in the following section.

NEMS-GPRA Inputs

NEMS-GPRA input specifications follow by program, and all are summarized in **Table 3**. Inputs for each program are briefly described in the following sections. As a general rule, no modifications are made to NEMS-GPRA input data prior to 2006, consistent with the notion that FY 2006 benefits begin in year 2006.

The AEO-4 case and prior GPRA forecasts were compared with the National Renewable Energy Laboratory's (NREL) and Gas Technologies Institute's Technology Characterizations (TeChars) for three technologies: microturbines, gas engines, and industrial gas turbines. When program goals were not available from the program office, technology cost and electrical efficiency inputs are derived both from the TeChars and from DE program goals.[1]

NEMS-GPRA often contains multiple sizes of each DE technology, yet the program goals are typically provided for a single representative unit size. As a result, the technology inputs for baseline and program cases are scaled using the TeChars to correspond to the units represented in NEMS-GPRA. This analysis assumes the DE program goal data represent a 1 MW gas engine, 5 MW gas turbine, and 100 kW microturbine, which are then scaled to accommodate the various sizes. For clarification, a summary table of technology type, module, and nameplate capacities represented in the GPRA06 case is included in **Table 1**.

Table 1. Summary of Technology Size Representation by Module

Technology Type	Module	Representative Size in NEMS
Gas Turbine	Commercial	1 MW
	Industrial	1 MW, 5 MW, 10 MW
	EMM	2 MW*
Microturbine	Commercial	100 kW
Gas Engine	Commercial	200 kW
	Industrial	800 kW, 3 MW
	EMM	1 MW*

* The 1 MW peak-load and 2 MW base-load units in the EMM module are composite plants made up of various technologies, a portion of which are gas engines and gas turbines, respectively.

While many of the technology inputs reflect the achievement of DE program goals by 2012, the exact replication of this time frame is not always possible because of certain model constraints. For example, technological progress for the commercial module absorption chiller, an additional technology not explicitly characterized by size, is limited to a step-function advance, and input

[1] Goldstein, Larry, Bruce Hedman, Dave Knowles, Steven I. Freedman, Richard Woods, and Tom Schweizer, (November 2003). "Gas-Fired Distributed Energy Resource Technology Characterizations," NREL/TP-620-34783.

values are specified in years 2000, 2005, and 2020. **Figure 12** represents this limitation. For this reason, it is not always possible to exactly replicate program goals in NEMS-GPRA.

Industrial Gas Turbines

Gas turbine sizes in NEMS-GPRA range from 1 to 40 MW, appearing explicitly in the commercial and industrial demand modules, and as part of a composite plant in the utility electricity market module (EMM), where this plant is represented by a mix of different technologies and is defined generically as either a base-load or peak-load system. The industrial-sector turbines cover a wide size range, but proposed inputs to the GPRA06 process focus on the 1 MW-, 5MW-, and 10 MW-size systems. Although larger turbines are not the focus of the program, the 25 MW and 40 MW gas turbines in the industrial sector are also modified in order to maintain consistency across the various sized turbines. The commercial sector contains a single representative turbine sized at 1 MW. The inputs for the commercial turbine were scaled to 1 MW using the 5 MW representative size gas turbine input data and the TeChars difference between these two units. The baseline and program case inputs for the commercial sector correspond to the 1 MW system shown in **Figures 1-3**. Also, a portion of the 2 MW base-load EMM generator is represented as a 1 MW gas turbine, which is discussed in a later section.

The *baseline* input values for industrial gas turbines reflect a 10-year lag from the program electrical and combined efficiencies. There is no cost difference between baseline and program cases, which are kept at the AEO-4 levels.

The *program* input values represent an improvement in electrical efficiency by 2006. Again, costs are kept at AEO-4 levels. The combined efficiency changes reflect target levels for 2006 and 2008, scaled to the various sized turbines using the TeChars difference from the 5 MW unit and kept flat thereafter. The main objective of this program currently is efficiency and performance improvement and NOx and CO emissions reduction; but, because emissions reductions are not reported metrics, forecasts for these improvements are not included here.

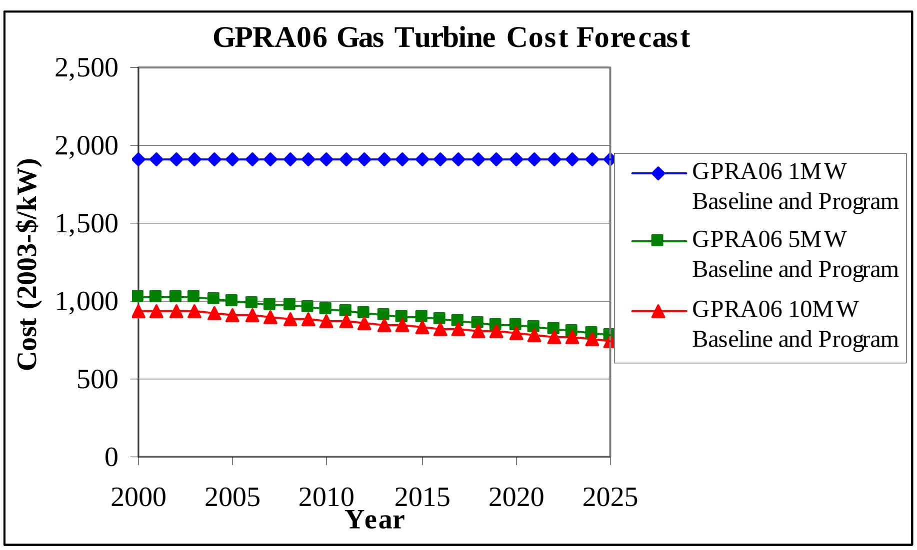

Figure 1. Industrial Gas Turbine Installed Cost

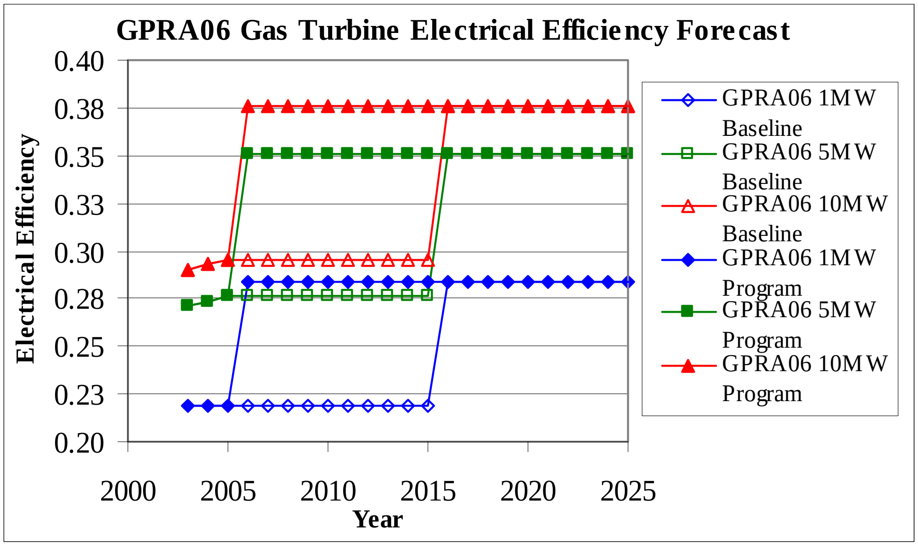

Figure 2. Industrial Gas Turbine Electric Efficiency

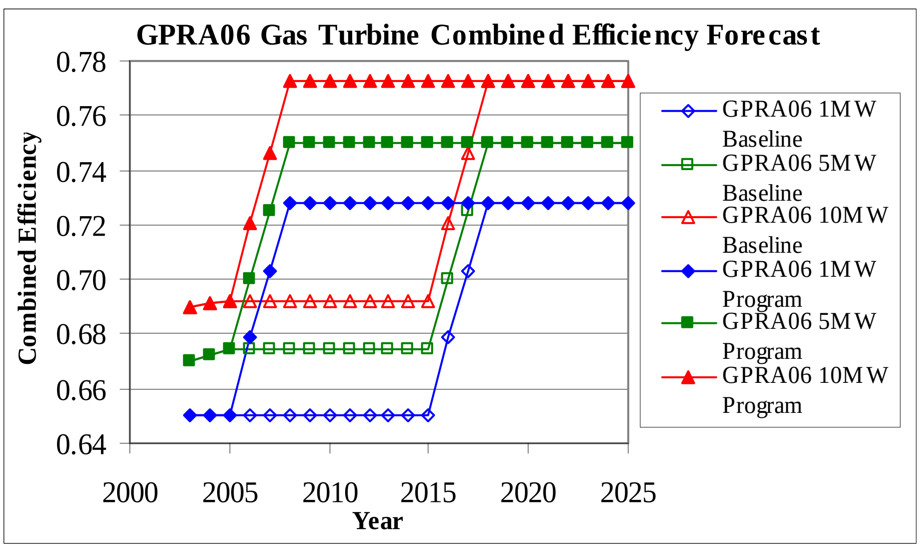

Figure 3. Industrial Gas Turbine Combined Efficiency

Advanced Microturbines

Microturbines occur only in the commercial module as a representative 100 kW system. Input data are therefore directly applied to this system without any scaling of different-sized units.

The *baseline* input values for costs, electricity conversion efficiency, and combined efficiency shown in **Figures 4-6**, respectively, represent a 10-year lag of the program input assumptions.

The *program* input values for cost are a 25% improvement from 2000 to 2008 with a continued trend through 2012. Costs therefore fall from $1,926/kW in 2000 to $1,231/kW by 2012 and are flat thereafter.

Because the AEO-4 microturbine electrical efficiency matches the TeChars projection, the program case assumes the AEO-4 with the baseline set to a 10-year lag of the program. Combined efficiency values are scaled to agree with the combined efficiency target provided for a 5 MW turbine using the relative difference between these two units in the TeChars publication. The combined efficiency reaches 71% by 2008 and is flat thereafter.

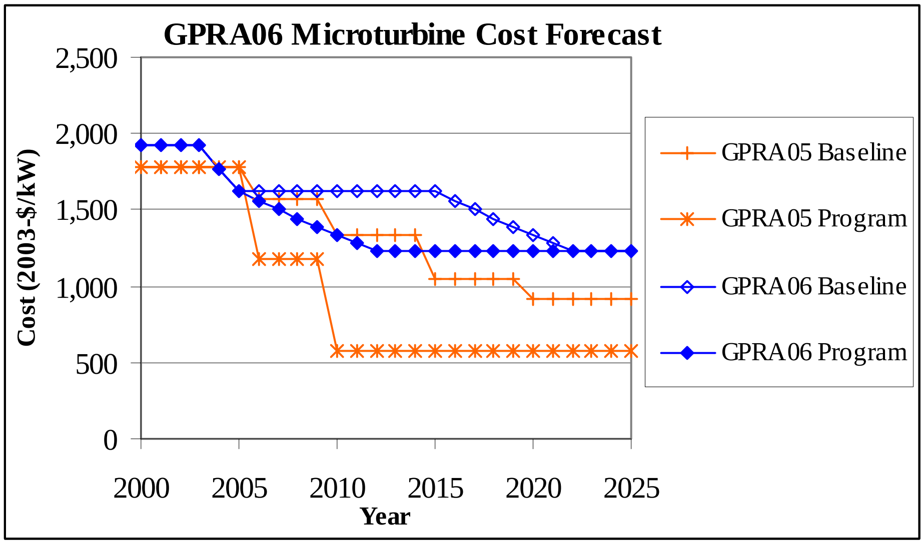

Figure 4. Microturbine Installed Cost

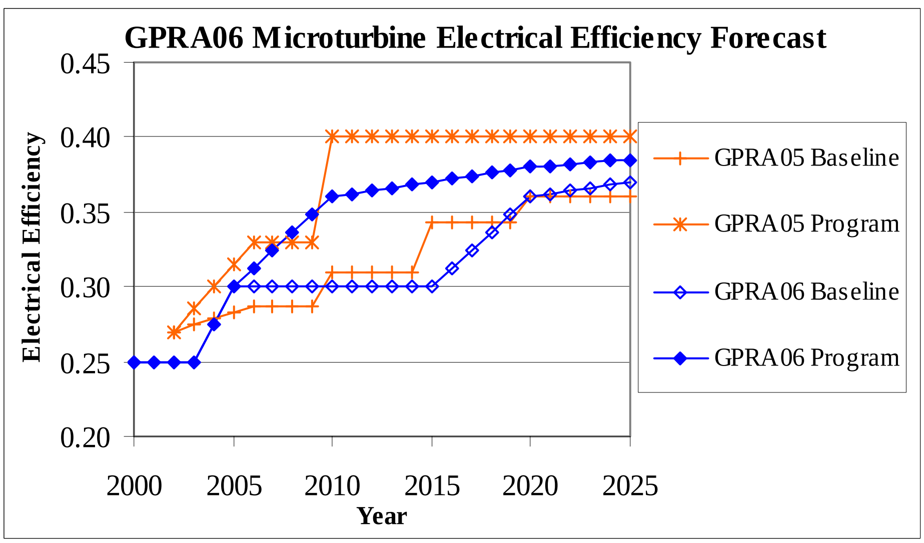

Figure 5. Microturbine Electric Efficiency

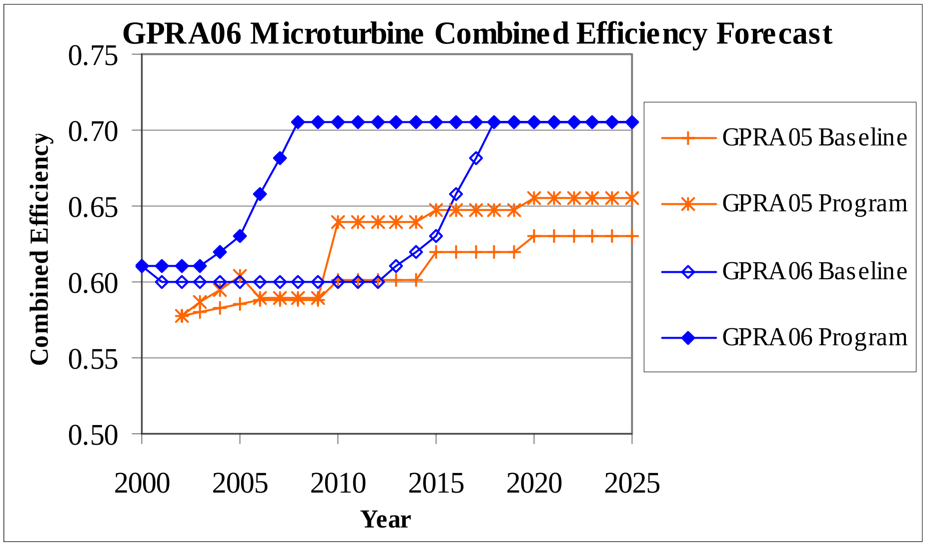

Figure 6. Microturbine Combined Efficiency

Gas-Fired Reciprocating Engines

Gas engines appear in several modules in NEMS, in both CHP and simple-cycle configurations, but only one or two marker models represent the wide range of available engines (see **Table 1**). The limited number of available technology slots, together with the maturity and clear attractiveness of gas engines in many configurations, makes the choice of inputs for this technology somewhat complex.[2] The commercial module has a marker 200 kW CHP-enabled unit, the industrial module has 800 kW and 3 MW CHP-enabled units, and the 1 MW unit that appears in the EMM also partially represents a simple-cycle gas engine as a composite plant for various technologies

The *baseline* input values for costs (see **Figure 7**), electricity conversion efficiency (see **Figure 8**), and combined efficiency (see **Figure 9**) are a 10-year lag from the program goal assumptions.

The *program* input values for the commercial and industrial engines are scaled from the inputs provided for a typical engine assumed to be 1 MW in size. However, the 800 kW engine in the industrial sector is represented by the 1 MW technology characteristics. The cost is represented as a 25% improvement from 2000 to 2008 with a continued trend through 2012, and flat thereafter. The electrical efficiency value for a 1 MW gas engine is assumed to be 42% by 2008, the cost is $601/kW by 2012, and the combined efficiency is 75% by 2008 and flat thereafter. The 200 kW commercial gas engine and 3 MW industrial gas engine are scaled from these targets using the relative difference in cost, electrical and combined efficiency in the TeChars.

[2] Heat recovery can be from exhaust gas or jacket coolant, and a promising CHP application is absorption- cycle cooling, which is non-existent in NEMS-GPRA.

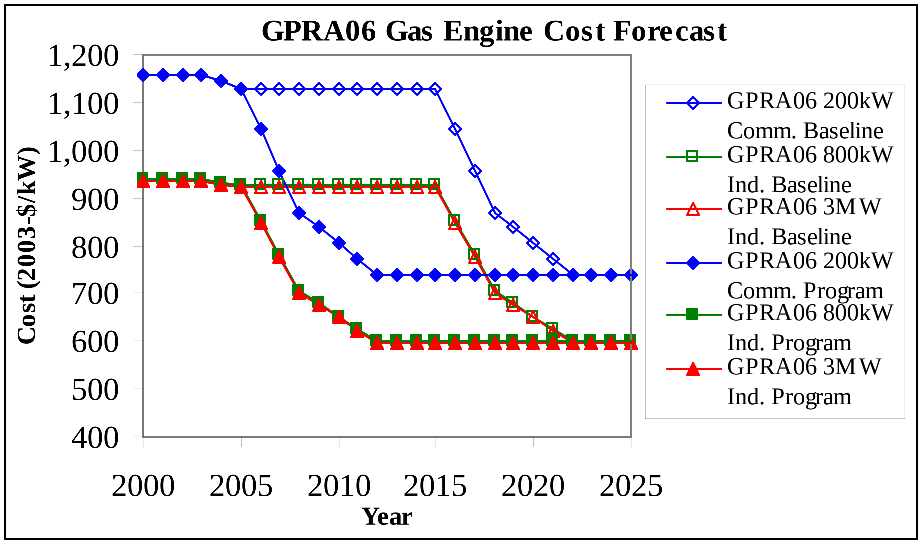

Figure 7. Gas Engine Installed Cost

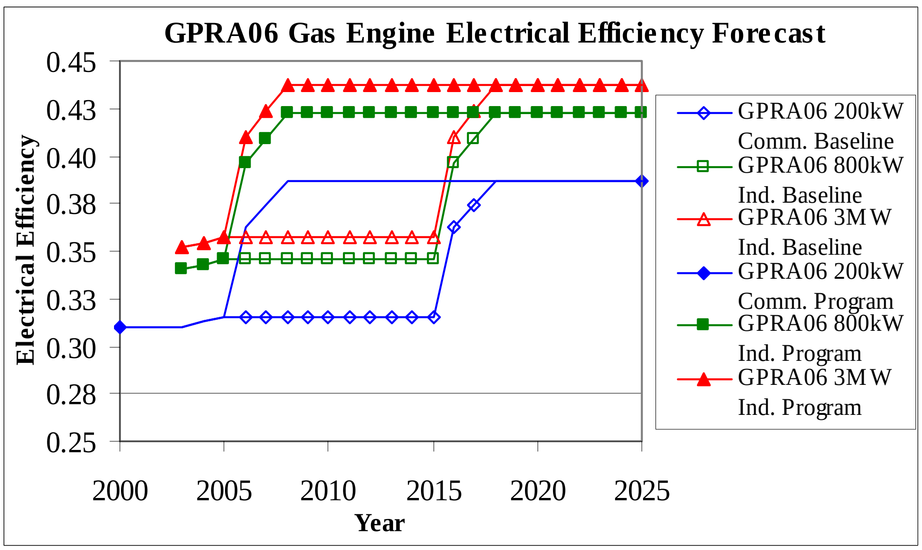

Figure 8. Gas Engine Electric Efficiency

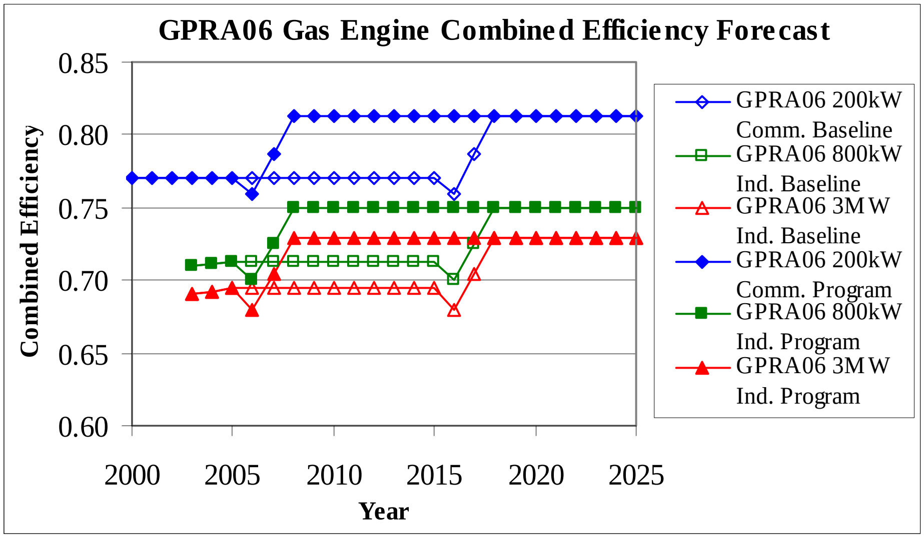

Figure 9. Gas Engine Combined Efficiency

Technology Representation in the Utility Sector (Electricity Market Module)

The EMM contains two generic DG technologies: a 2 MW base-load system and a 1 MW peak-load system, neither with CHP capability. Baseline and program representation of these technologies correspond to a projection based on a composite of various technologies. The 1 MW peak-load system's assumed composition is 80% gas engine and 20% microturbine from 2010 onward. The 2 MW base-load system assumes a make up of 20% gas engine, 20% gas turbine, 20% microturbine, and 40% fuel cell from 2010 onward. These modified weightings are taken from a study by Joe Iannucci of Distributed Utility Associates.[3] The technology characteristics of the gas engine, gas turbine and microturbine in these two composite plants are replaced with the 1 MW gas engine, 5 MW gas turbine, and 100 kW microturbine assumptions, respectively, to match the baseline and program goals. For the baseline, the EMM systems do not assume a 10-year lag of the program. Instead, separate trajectories for the baseline and program cases based on the Iannnucci study are assumed. **Figure 10** shows the cost trajectory and **Figure 11** illustrates the modified heat rate assumptions.

Although CHP applications may be attractive to utilities, DG systems in the EMM do not include heat-recovery components, and therefore projected technology costs are slightly lower.

[3] "Assessing Market Acceptance and Penetration for Distributed Generation in the United States", Distributed Utility Associates, June 1999.

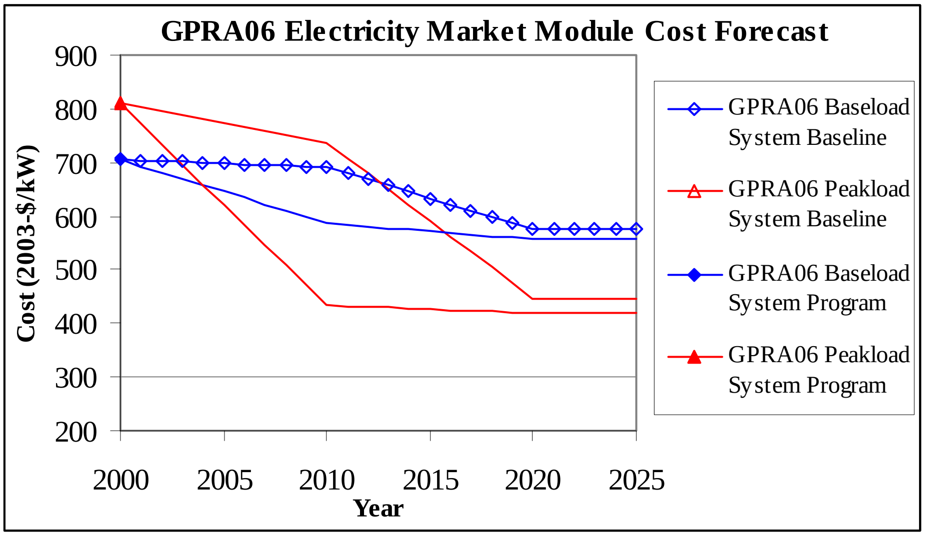

Figure 10. Electricity Market Module Installed Cost

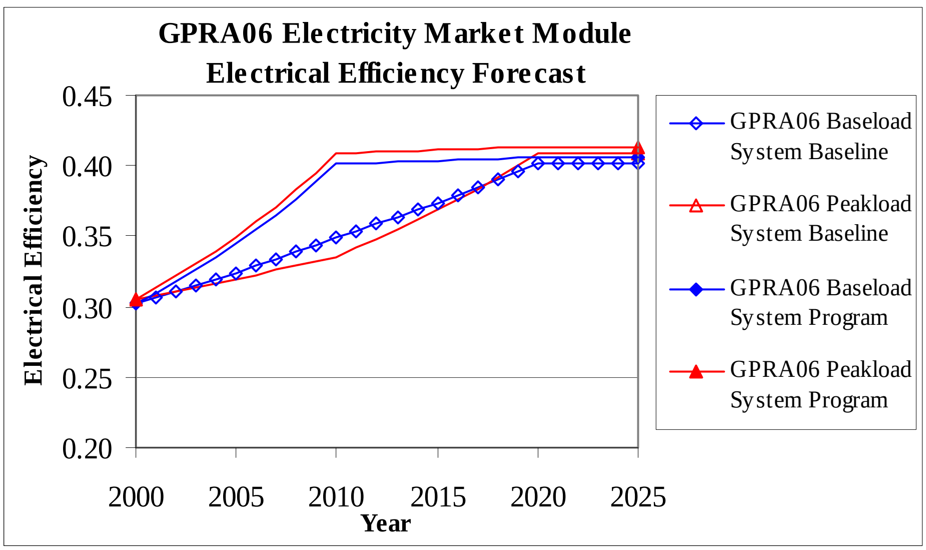

Figure 11. Electricity Market Module Electrical Efficiency

Advanced Materials

No separate inputs to represent this program are proposed. The benefits of this activity are represented in the preceding technology-development activities.

Thermally Activated Technologies

DE's thermally activated technologies program includes direct-fired absorption chiller technologies and desiccant dehumidification systems. Only the former are represented here as changes applied to gas-fired absorption chillers in the commercial technology input file.

The NEMS-GPRA commercial module represents the commercial building stock using 11 representative building types. Of these, the commercial technology input file restricts gas-fired absorption chillers from being installed in the following building types: food sales, food service, small office, warehouse, and other. These restrictions are removed for both the baseline and program cases to allow systems to be installed in all buildings.

The assumptions for the program case inputs include: cost-improvement data taken from Resource Dynamics' study of integrated energy systems[4] with future cost values (2005+) available in 2010; double-effect chillers are approximately 1.5 times the cost of single-effect chillers; and technology costs correspond to 50–100 cooling ton[5] range. **Table 2** and **Figure 12** shows the cost and COP assumptions for this technology.

The *baseline* case, based on a double-effect chiller introduced in 2020, uses cost assumptions from the AEO-4 with improvement in year 2020 and modest COP improvements in 2005 and again in 2020.

The *program* case is based on a double-effect chiller introduced in 2005 represented as an improvement to the cost and COP with further COP improvement in 2020. The cost improvement is introduced in 2005.

Table 2. GPRA06 Inputs for DE's Thermally Activated Technologies Program

	Baseline Case			Program Case		
Year	COP	Cost ($/kBtu/hr)	Cost ($/cooling ton)	COP	Cost ($/kBtu/hr)	Cost ($/cooling ton)
2000	1.0	78.75	945	1.0	78.75	945
2005	1.2	78.75	945	1.3	50.00	600
2010	1.2	78.75	945	1.3	50.00	600
2020	1.3	50.00	600	1.4	50.00	600

[4] LeMar, P. (August 2002). "Integrated Energy Systems (IES) for Buildings: A Market Assessment," Resource Dynamics.
[5] *1 cooling ton is equal to 12,000 Btu/hr or approx 3.5 kW thermal.*

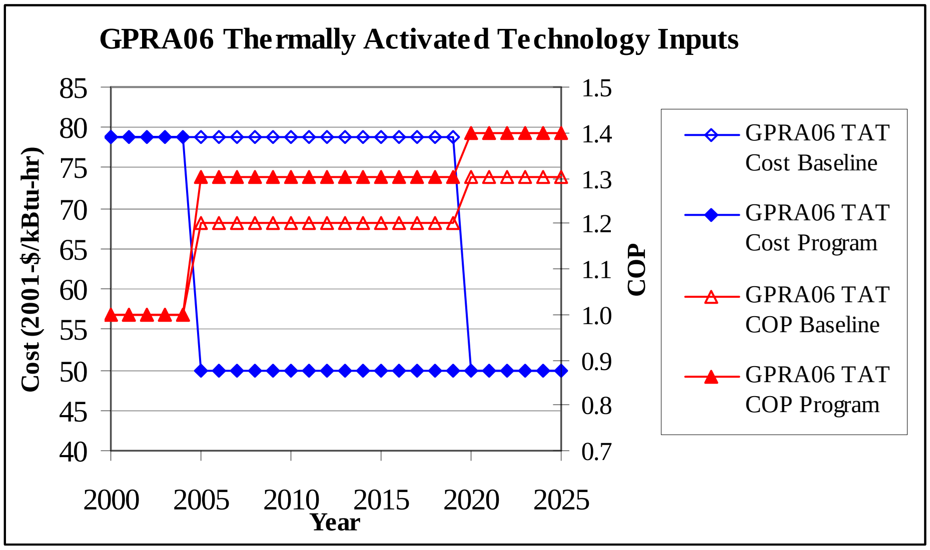

Figure 12. Thermally Activated Cooling Technology Inputs

Distributed Energy Systems Applications Integration

The Distributed Energy Systems Applications Integration (DESAI) Program strives to accelerate adoption of DG technologies in certain sectors, especially among the existing building market (i.e. through retrofits). The NEMS model calculates DG adoption in *existing* buildings as a predetermined fixed share of the adoption in *new* buildings, and that share is set at 0.5% in the AEO-4 Reference Case. Because the retrofit market is the primary target of the DESAI Program, the outputs are represented by an increase in the cap on the share of existing commercial sites that can adopt DG.

The *baseline* input values are achievements of cost and efficiency targets by 2020. The existing building adoption rate is 0.5% of new buildings, equivalent to the AEO-4 value.

The *program* input values increase the share of existing buildings eligible to adopt DG from 0.5% to 10% of new buildings.

As part of the DG adoption logic fixes described in Section 9, additional changes to the new building adoption parameter were made in addition to the DESAI Program representation.

Cooling Heating and Power Integration

This program develops improved CHP packages and otherwise supports the market penetration of CHP technologies, including indirect-fired absorption chillers. Because NEMS-GPRA does not have a representation of indirect-fired absorption chillers, this program is represented by a proxy improvement in the payback period of the prime mover technology equivalent to the economic benefit of using 25% of the generator waste heat for a cooling end use.

The *baseline* input values are a 10-year lag of the program input values.

The *program* input values are a target 70% combined efficiency level in 2006 and 75% level in 2008 assumed to represent a typical 1 MW gas engine or 5 MW gas turbine. The target was scaled using the TeChars to the various sized CHP capable technologies in the industrial and commercial sectors. Additionally, a commercial module customer payback adjustment is also made to incorporate the added benefits of absorption cooling capability in gas engines and microturbines. The corresponding energy savings from enhanced absorption cooling deployment are also adjusted as impacts to commercial end-use consumption. This adjustment also increases heating consumption if not all the waste heat is available to meet the load.

DG Adoption Logic Fixes

Two fixes were made to the DG adoption logic of new buildings in the commercial sector of NEMS-GPRA for both baseline and program cases. The adoption algorithm for DG in new buildings caps the maximum market adoption rate (the *penparm* parameter) at 30% for a one-year payback level. The NEMS cap on adoption rates for different paybacks (max *pen)* decays as an inverse function at a rate of 1/years to positive cash flow, and this decay is known as the payback acceptance function (shown as equation 1 below).

$$\max pen = \frac{penparm}{payback} \quad (1)$$

This approach severely disfavors technologies with paybacks that are moderate but still quite acceptable to many building owners—such as in the three- to six-year range—while it allows smaller adoption at very long paybacks, such as 15 years.

First, the cap for new buildings with a one-year payback (represented by the *penparm* parameter) is raised from 30% to 50%. A similar change was made in the GPRA05 analysis.

Second, the payback acceptance function is changed from an inverse decay function to one based on data of observed customer adoption of energy efficiency projects as a function of simple payback time[6]. These data are shown below for buildings in the institutional sector (n=768) and commercial buildings in the private sector (n=108).

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

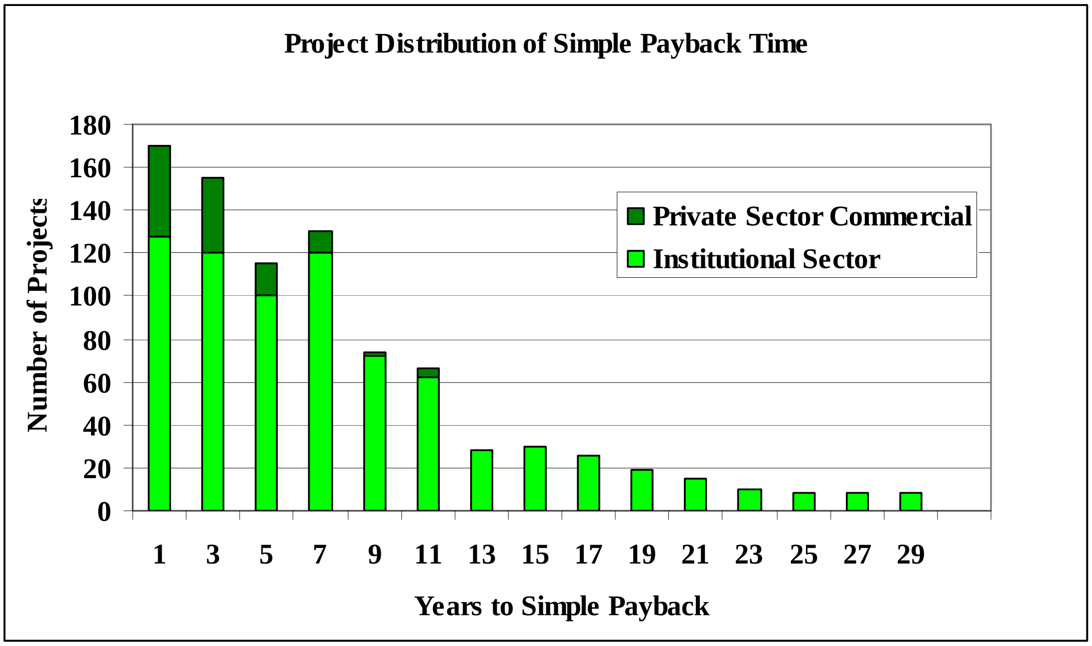

Figure 13. Distribution of Years to Simple Payback

To determine a decay function for the max *pen* based on this data set, the percentage of potential adopters from the total sample for each given payback year is calculated. It is assumed that for a given payback year, all of the adopters in that year and all adopters of projects with shorter payback periods would adopt, i.e. all columns are summed to the right in **Figure 13**. These data show that the relationship between the project payback period and the number of buildings that adopt the project is approximately linear for a payback between 1 and 11 years, and then falls off sharply at years 13 and higher. For example, all adopters of projects with 29-year paybacks also would adopt projects with 27-year paybacks, 25-year paybacks, etc. The resulting customer-acceptance curve is shown in **Figure 14**, along with the mathematical representation of the revised curve for input to NEMS-GPRA and the current equation used in the AEO-4. **Figure 14** shows that a maximum of 100% will adopt, and this represents 100% of the sample size; however, in NEMS-GPRA, the percentage of the total population that actually will adopt is scaled down using the *penparm* parameter (set at 50% for GPRA06), as discussed above.

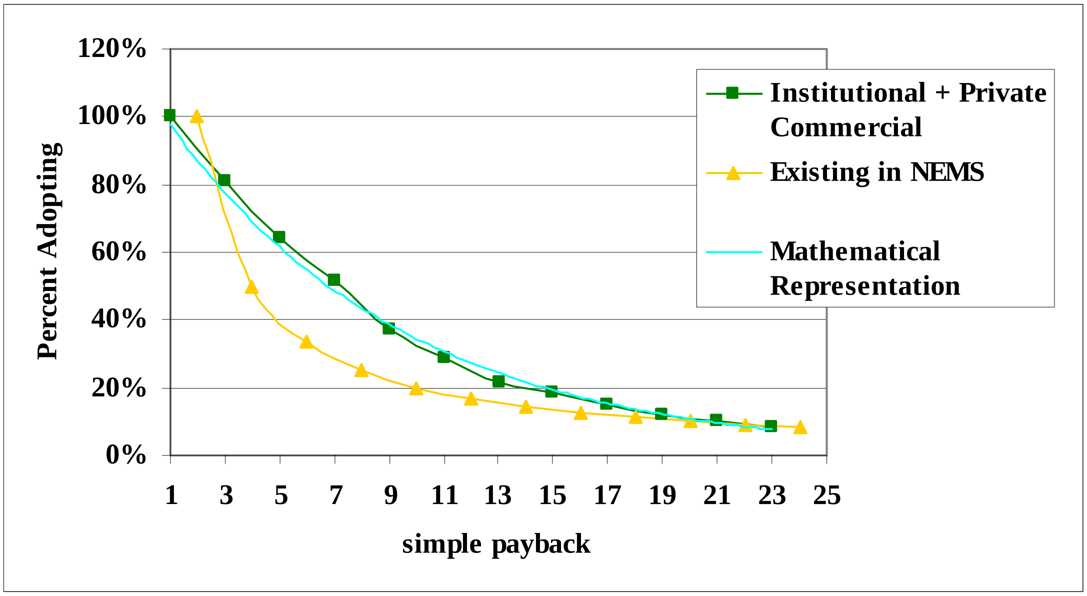

Figure 14. Decay Function of the Maxpen

NEMS-GPRA uses the number of years to positive cash flow[7], and not simple payback, as the primary metric of DER adoption. Figure 14 converts the data to years to positive cash flow by dividing the simple payback time in half. A simple spreadsheet analysis was used to determine the relationship between simple payback and years to positive cash flow, assuming the NEMS-GPRA financing assumptions. This analysis determined that, with NEMS-GPRA financing assumptions in place, the number of years to positive cash flow of a project is approximately half of the payback period. Ultimately, the decay above is represented by equation 2 below as a function of the *payback* variable as defined in NEMS-GPRA:

$$\max pen = \frac{1.1 penparm}{e^{0.24\, payback}} \quad (2)$$

One additional NEMS-GPRA fix has been implemented in the base and program cases to ensure that the changes to the adoption logic described above do not result in an exaggerated number of DG adoptions. An internal check is included to ensure that the percentage of existing buildings that have DER systems installed does not exceed the cap imposed on new buildings. This will prevent a case where the installations in new buildings are not allowed to reach the rate of existing buildings.

The NEMS-GPRA fixes, along with additional minor changes, are summarized in **Table 4**.

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[7] The NEMS *payback* (or *simple payback)* variable is defined as the first year in the cash-flow stream for which an investment has a positive cumulative net cash flow. *(EIA, NEMS Commercial Module Documentation Report 2004, EIA/DOE-MO66(2004))*

Market Uptake

For industrial gas turbines, a modification in the customer acceptance payback distribution was made to reflect a market transformation improvement from the DESAI program. This change alters the payback distribution, allowing more customers to accept a shorter payback period. As well, a change is made to relax the yearly penetration rate for gas turbines from a maximum 5% to 10%. The rationale for these modifications was to reflect improvements in the technical barriers of CHP adoption.

No market potential or penetration analyses were done exogenously to NEMS-GPRA for this work. The market definition and penetration rates for DG are those that are endogenous to NEMS-GPRA, and these are described briefly here for the EMM and the Commercial Demand Module.

In the EMM, the market is driven by the growing electricity-demand forecast and the deferred cost of transmission and distribution (T&D) expansion. The two available DER generators (the peak and base-load units) compete against the cost of central-station generation and T&D upgrades to supply growing demand and replace retiring generating capacity. The total capacity of DG is constrained to correspond to a specific level of avoided T&D costs, indicating that there is a maximum economic value of T&D deferrals that DG can provide.[8]

In the NEMS commercial sector, the market is represented by 11 building types and is disaggregated into nine geographic census divisions or regions. Annual penetration into the new-building market is determined by the economic attractiveness of on-site generation with heat recovery relative to the purchase of electricity and other fuels. The retrofit market is not characterized distinctly, and the market adoption is simply proportional to the new-building adoption. Distributed generation adoption in the commercial sector is dominated by a few building types. The education, lodging, and mercantile/service sectors account for the large majority of DG capacity additions from the DE program. Regional DG adoption is distributed more evenly among census divisions, though the Pacific and Middle Atlantic regions account for a larger share of DG adoption, partly because of the higher electricity demand and prices forecasted for those regions.

Because DG market segments are broadly characterized in NEMS, an accurate representation of niche market adoption is difficult to include exogenously in NEMS-GPRA. Several niche market segments that contribute to the total market for DG (such as markets for reliability, security, or environmental benefits) are not represented in NEMS-GPRA.

[8] Energy Information Administration (2003). "The Electricity Market Module of the National Energy Modeling System: Model Documentation Report," U.S. Department of Energy, Washington, D.C. pg.91.

Table 3. Summary of DE Program and Baseline Representation in GPRA06

	DE Program	Program Goals	Representation in NEMS-GPRA	
			Baseline	Program
Technology Development	Industrial Gas Turbines	- 35% electric efficiency HHV - 0.5 g/kWh NOx by 2000, 0.4 g/kWh NOx by 2005, and 0.2 g/kWh NOx by 2008	- 10-year lag of Program case - EMM 1 MW baseload composite unit assumes forecast determined from Joe Iannucci report weightings	- Industrial module: electrical efficiency is 28%, 35%, and 38% for 1, 5, and 10 MW systems, respectively by 2006 and flat thereafter; combined efficiency values at 73%, 75%, and 77% respectively by 2008. - EMM baseload unit considered a composite plant without CHP capability with 20% gas turbine make-up. - Commercial module equivalent to 1 MW values.
	Advanced Microturbines	- 32% electric efficiency HHV by 2005, 33% electric efficiency HHV by 2008 - 0.4 g/kWh NOx by 2005, 0.2 g/kWh NOx by 2008	- 10-year lag of Program case	- 25% cost improvement from 2000 to 2008 and continuing trend through 2012- reaches 1,231$/kW by 2012 - electric efficiency is kept at AEO-4 value because it represents TeChars - 66% and 71% combined efficiency level by 2006 and 2008, respectively.
	Gas-Fired Reciprocating Engines	- 40% electric efficiency (HHV) by 2005, 42% electric efficiency (HHV) by 2008 - $380/kW by 2006, $360/kW by 2008 - 2.1 g/kWh NOx by 2006, 1.1 g/kWh NOx by 2008	- 10-year lag of Program case - EMM 1 MW peaker composite unit assumes forecast determined from Joe Iannucci report weightings	- 200 kW commercial module unit: 39% electric efficiency by 2008, $741/kW by 2012, 87% combined efficiency by 2008 - Industrial module 1 MW and 3 MW units: 42% and 44% electric efficiency by 2008, 25% cost improvement from 2000 to 2008 and continuing trend through 2012 or $601/kW and $597/kW, 75% and 73% combined efficiencies by 2008, respectively. - EMM 1 MW peaker unit is a composite plant without CHP capability with a 80% engine make-up.
	Technology Based-Advanced Materials and Sensors	Advanced material research to assist in other program goals	No additional changes	Included in acceleration cases represented by End-Use Integration programs

	DE Program	Program Goals	Representation in NEMS-GPRA	
			Baseline	Program
	Thermally Activated Technologies	Cost and efficiency improvements for direct-fired absorption chillers	- COP of 1.2 (2005) and 1.3 (2020), $79/kBtu-hr (2005) - $51/kBtu-hr (2020); allow installations in all building types	- COP of 1.3 (2005) and 1.4 (2020), $51/kBtu-hr by 2005 - allow installations in all building types
End-Use Integration	Distributed Energy Systems Applications Integration	Demonstration and integration projects in industrial sector, high-tech industry, hospitals, and other commercial sectors.[9]	- Percent of existing buildings that adopt DER set at 0.5% of new buildings (same as AEO-4)	- Percent of existing buildings that adopt DER increased to 10% of new buildings.
End-Use Integration	Cooling Heating and Power Integration	Combined efficiency target of 70% by 2006 and 75% by 2008	- 10-year lag of Program case - Reduce the payback years for commercial gas engines and microturbines to account for enabled absorption chiller capability	- Apply CHP 2006 and 2008 CHP targets to commercial gas engine, gas turbine, and microturbine and industrial 1MW and 3MW gas engines and 1MW, 5MW, and 10MW gas turbines and scaling the CHP target to different size units using the TeChars - Reduce the payback years for commercial gas engines and microturbines to account for enabled absorption chiller capability

[9] The National Accounts Energy Alliance focuses on "Fortune 1000, national chain end-users, including the retail, supermarket, food service, hotel, and healthcare industries."

Table 4. Additional NEMS-GPRA Enhancements for both the Baseline and Program Cases

Change	Module	Program or Baseline	Implemented in NEMS-GPRA	Source/Rationale
Maximum Annual Penetration Caps for New Buildings	Commercial	Both	*Penparm* parameter currently set to 30%, change to 50%	Change made in GPRA05
Maximum Annual Penetration Caps for Existing Buildings	Commercial	Both	Remove penetration cap of 0.5% new building penetration	Additional methods are implemented to prevent oversaturation in existing buildings
Falloff of Maximum Annual Penetration Caps as a Function of Payback Years	Commercial	Both	Currently set as an inverse function: $\max pen = \frac{penparm}{simplepayback}$ Change to: $\max pen = \frac{1.1 penparm}{e^{0.24 simplepayback}}$	*Market Trends in the U.S. ESCO Industry: Results from the NAESCO Database Project*. Goldman, C., J. Osborn and N. Hopper, LBNL, and T. Singer, NAESCO, May 2002, LBNL-49601.
Adjust commercial customer payback for gas engines and microturbines to include absorption cooling capability in these technologies	Commercial	Both	Modify *isimplepayback* for gas engines and microturbines by Census Division, building type, and year and corrected for change in energy consumption as a result of increased absorption cooling.	NEMS does not consider absorption cooling.
Adjust industrial customer acceptance payback distribution and relax the yearly penetration rate for gas turbines to reflect market transformation improvements with CHP	Industrial	Program	Modify the payback acceptance curve giving a greater acceptance rate for shorter paybacks. Also increased the yearly penetration rate from 5% to 10%.	Representing market transformation advancements of the CHP program.