Cost and Performance Assumptions for Modeling Electricity Generation Technologies

Rick Tidball, Joel Bluestein, Nick Rodriguez, and Stu Knoke

ICF International

Fairfax, Virginia

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Subcontract Report

NREL/SR-6A20-48595

November 2010

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

Cost and Performance Assumptions for Modeling Electricity Generation Technologies

Rick Tidball, Joel Bluestein, Nick Rodriguez, and Stu Knoke
ICF International
Fairfax, Virginia

NREL Technical Monitor: Jordan Macknick

Prepared under Subcontract No. KACX-8-88312-04

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401
303-275-3000 • www.nrel.gov

Subcontract Report
NREL/SR-6A20-48595
November 2010

Contract No. DE-AC36-08GO28308

This publication received minimal editorial review at NREL.

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information

P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/help/ordermethods.aspx

Cover Photos: (left to right) PIX 16416, PIX 17423, PIX 16560, PIX 17613, PIX 17436, PIX 17721

Printed on paper containing at least 50% wastepaper, including 10% post consumer waste.

Table of Contents

List of Figures

List of Tables

1 Introduction

1.1 Objective

The goal of this project was to compare and contrast utility scale power plant characteristics used in data sets that support energy market models. Six specific data sets – each associated with a different model – were selected for the study. The data sets and corresponding models are shown in Table 1. Details concerning each data set and model are contained in Appendix A through Appendix F. It is important to note that two of the data sets (AEO 2009 and MiniCAM 2008) represent modeled results, not direct model inputs. These two data sets include cost and performance improvements that result from increased deployment (termed "learning by doing") as well as resulting capacity factors estimated from particular model runs, whereas other data sets represent data before the model is run. The differences in capacity and availability factors that result from this discrepancy are discussed in further detail in Section 2.3, and learning rate differences are discussed in Section 3.2.

Table 1. Six Data Sets Used by Six Models

Data Set			Model	
Designation	Time Horizon	Data Type	Name	Owner
AEO 2009	2030	Modeled result	NEMS – National Energy Modeling System	Energy Information Administration (EIA)
GPRA 2009	2050	Model input	MARKAL – Market Allocation	International Energy Agency[1] and Brookhaven National Laboratory
NREL-SEAC 2008[2]	2050	Model input	ReEDS – Regional Energy Deployment System	National Renewable Energy Laboratory (NREL)
MiniCAM 2008	2050	Modeled result	MiniCAM – Mini Climate Assessment Model	Pacific Northwest National Laboratory (PNNL)
EPA 2009	2035	Model input	IPM – Integrated Planning Model	ICF International
MERGE 2009	2050	Model input	MERGE – Model for Estimating the Regional and Global Effects of Greenhouse Gas Reductions	Electric Power Research Institute (EPRI)

In addition to comparing and contrasting power plant characteristics, the levelized cost of energy (LCOE) was evaluated for the technologies contained in each data set. LCOE values were computed using an Excel spreadsheet – referred to as the "LCOE tool" – created during this project. The LCOE tool was developed to handle up to 29 unique technologies spanning seven energy sources – coal, natural gas, nuclear, biomass, geothermal, wind, and solar. A description of the LCOE tool is provided in Appendix G.

[1] The Energy Technology Systems Analysis Programme (ETSAP) was formed through an International Energy Agency (IEA) Implementing Agreement. ETSAP oversees the MARKAL model.

[2] For the ReEDS model, three NREL-SEAC data sets were considered corresponding to three different years (2008, 2009, and 2010). Based on discussions with NREL, the NREL-SEAC 2008 data set was selected for analysis in this report.

1.2 Technologies Covered

The six data sets cover a wide range of technologies that include both the existing fleet of power generation plants as well as new plants that may be built to meet future electricity needs. This project is focused on new power plants that may be built in coming years, and a list of new power plant technologies included in each data set is shown in Table 2.

Table 2. New Electricity Generation Technologies by Data Set[3, 4]

		Data Set					
Technology		**AEO 2009**	**GPRA 2009**	**NREL-SEAC 2008**	**MiniCAM 2008**	**EPA 2009**	**MERGE 2009**
Coal							
Pulverized Coal	Scrubbed	X		X	X	X	X
	Scrubbed, w/ biomass cofiring			X			
	Adv, 1^{st} gen, w/ carbon capture						X
	Adv, 2^{nd} gen, w/ carbon capture						X
IGCC (advanced coal)	Conventional	X		X	X	X	X
	Adv, 1^{st} gen, w/ carbon capture	X		X	X	X	X
	Adv, 2^{nd} gen, w/ carbon capture						X
Natural Gas (includes dual fuel)							
Combustion Turbine	Conventional	X			X		
	Advanced	X		X		X	
Combined Cycle	Conventional	X			X		
	Advanced	X		X		X	X
	Adv. w/ carbon capture	X		X	X		
Distributed Generation	Base	X					
	Peak	X					
Fuel Cells		X				X	
Nuclear		X		X	X	X	X
Hydro							
Conventional		X		X			
Build-out on powered							
Build-out on unpowered							
Upgrade							
Small							
Wind							
Onshore	All wind classes	X	X	X	X	X	X
Offshore	All wind classes	X	X	X			

[3] Table shows technologies that may be installed in the future. Table does not include plants that currently exist in the power generation fleet that are not expected to be installed in the future.
[4] Technologies marked with boldface "X"s are the focus technologies in this report.

Technology	Data Set					
	AEO 2009	GPRA 2009	NREL-SEAC 2008	MiniCAM 2008	EPA 2009	MERGE 2009
Solar						
PV	X	X	X	X	X	X
Solar Thermal	X	X	X	X	X	X
Geothermal						
Hydrothermal	X	X	X	X	X	
EGS		X	X			
Biomass						
MSW, Landfill Gas	X		X		X	
Other	X		X	X	X	X
Energy Storage						
Battery			X			
Compressed air energy storage (CAES)			X			
ICE Storage			X			
Pumped Hydro			X			

Technical performance and cost characteristics were collected for each of the technologies listed in Table 2. Characteristics were gathered for each year within the time horizon covered by each data set. These characteristics were then reviewed for accuracy and entered into an Access database to facilitate data retrieval, analysis, and maintenance.

For the analysis discussed throughout this report, the technologies shown in Table 2 were narrowed to 11 focus technologies as indicated in Table 3. These 11 technologies represent power generation options that are generally regarded to have a significant role in meeting the future demand for electricity. This portfolio of power plants includes a cross section of fossil, nuclear, and renewable technologies

Table 3. Eleven Focus Technologies for This Report

Energy Source	Utility Scale Power Generation Technology
Coal	Coal (pulverized coal plant); Integrated Gasification Combined Cycle (IGCC)
Natural Gas	Combustion Turbine (advanced) [5]; Combined Cycle (advanced) [6]
Nuclear	Nuclear plant
Biomass	Biomass gasification plant
Geothermal	Hydrothermal
Wind	Onshore[7]; Offshore[8]
Solar	Solar Thermal[9, 10]; Photovoltaic (utility scale PV)

The 11 technologies are not all contained in each data set. Some data sets (e.g., AEO 2009, NREL-SEAC 2008, and EPA 2009) have broad coverage of power generation plants and include most, or all, of the 11 technologies. Other data sets are focused on particular technologies (e.g., the GPRA data set is focused on the Department of Energy's Energy Efficiency and Renewable Energy (EERE) technologies), and these data sets contain a subset of the 11 technologies. A matrix of the 11 technologies that are contained in each of the six data sets is shown in Table 4. The technologies contained in each data are also indicated in Table 2 (marked with boldface "X").

Table 4. Technologies Covered in Each Data Set (11 technologies)

	Data Set					
Technology	AEO 2009	GPRA 2009	NREL-SEAC 2008	MiniCAM 2008	EPA 2009	MERGE 2009
Coal	X	---	X	X	X	X
IGCC	X	---	X	X	X	X
Combustion Turbine	X	---	X	X	X	---
Combined Cycle	X	---	X	X	X	X
Nuclear	X	---	X	X	X	X
Biomass	X	---	X	X	X	X
Geothermal (hydrothermal)	X	X	X	X	X	---
Wind (onshore)	X	X	X	X	X	X
Wind (offshore)	X	X	X	---	---	---
Solar Thermal	X	X	X	X	X	X
PV	X	X	X	X	X	X

[5] The MiniCAM 2008 data set did not have an advanced technology, and the MiniCAM conventional technology was used for comparison with other data sets.
[6] Ibid.
[7] For NREL-SEAC 2008, Class 5 onshore wind is used for comparisons to other data sets.
[8] For NREL-SEAC 2008, Class 5 offshore wind (shallow) is used for comparisons.
[9] For NREL-SEAC 2008, Class 4 solar thermal is used for comparisons.
[10] The MiniCAM 2008 and GPRA 2009 data sets include thermal energy storage with solar thermal power plants. No other data sets in this study include energy storage with solar thermal plants.

1.3 Report Organization

The report organization is shown in Table 5. In Section 2, the technical performance parameters for the electricity generation technologies contained in the data sets are discussed. In Section 3, the overnight capital cost and the operation and maintenance (O&M) costs are compared and contrasted. In Section 4, a summary of LCOE values is presented, including an analysis of the sensitivity of LCOE results to several parameters.

Table 5. Report Organization

Section	Title
1	Introduction
2	Technical Performance Characteristics
3	Cost Characteristics
4	Levelized Cost of Energy
5	Conclusions

2 Technical Performance Characteristics

The comparison of technical performance characteristics is organized as follows:

- Plant Size
- Heat Rate
- Availability Factor (Capacity Factor)
- Plant Lifetime

2.1 Plant Size

Table 6 shows the plant sizes for 11 technologies in each of the six data sets. The power plant sizes, including the standard deviation and the coefficient of variation, are shown in Figure 1. The coefficient of variation is expressed in percent and is equal to the standard deviation divided by the mean.

Table 6. Plant Size (MW)

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	600	---	600	600	600	675	34	5%
IGCC	550	---	550	550	550	800	112	19%
Combustion Turbine	230	---	160	160	230	---	40	21%
Combined Cycle	400	---	300	250	400	450	82	23%
Nuclear	1,350	---	1,000	1,350	1,350	1,400	164	13%
Biomass	80	---	100	80	80	75	10	12%
Geothermal (hydrothermal)	50	50	50	50	50	---	0	0%
Wind (onshore)	50	50	100	50	50	100	26	39%
Wind (offshore)	100	100	100	---	---	---	0	0%
Solar Thermal	100	100	200	100	100	125	40	33%
PV	5	5	100	5	5	20	38	163%

Note: Coefficient of variation (CV) is the standard deviation divided by the mean.

As indicated in Table 6 and Figure 1, the coefficient of variation (CV) is less than 50% for all technologies with the exception of PV systems, which have a CV of 163%. Depending on the data set, PV plant sizes range from 5 MW to 100 MW. PV for utility scale generation is an emerging technology, and many different plant sizes and configurations have been proposed. These variations have a wide range of capacities, leading to a large standard deviation (PV standard deviation equal to 38 MW; coefficient of variation equal to 163%).

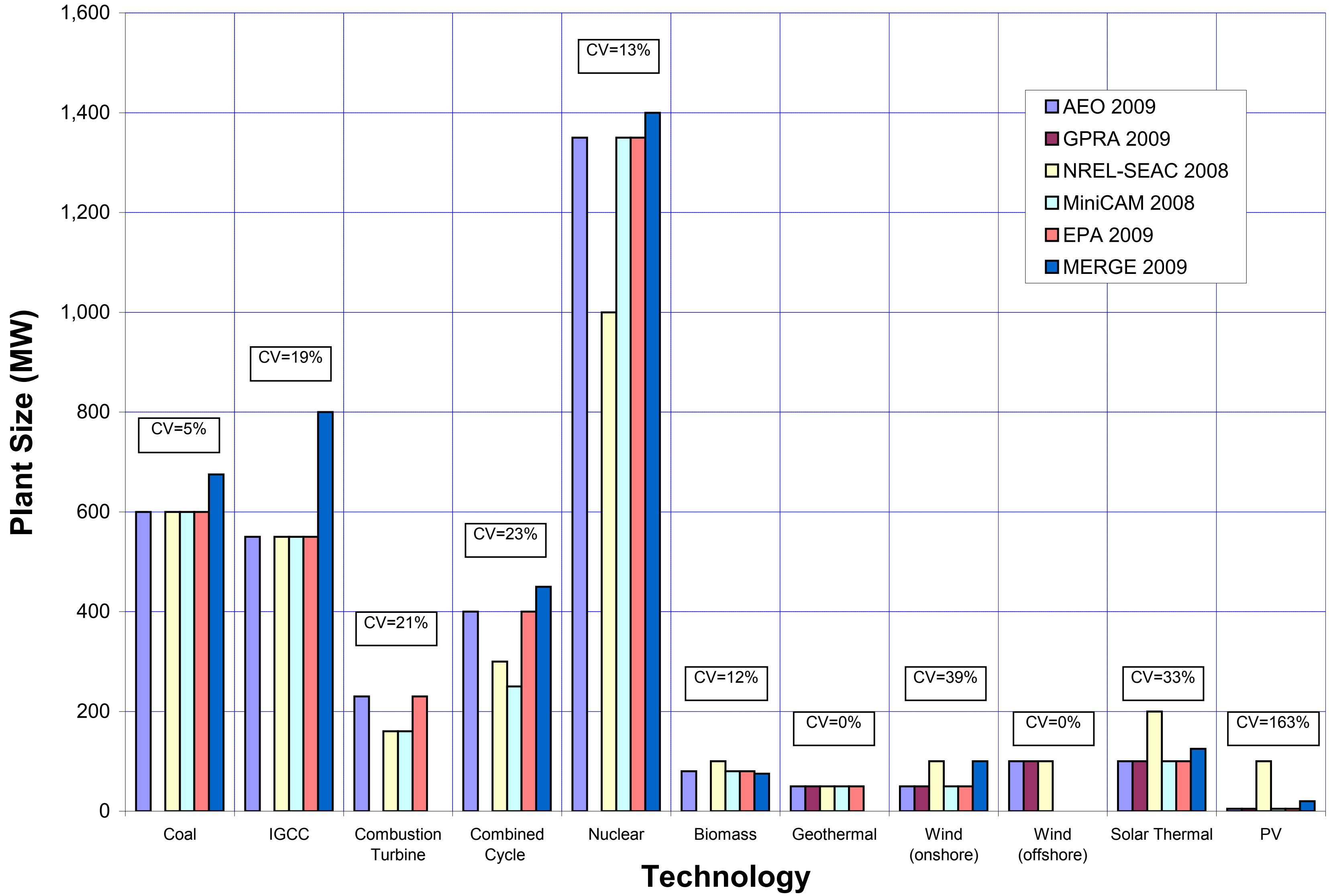


Figure 1. Power plant size comparison

2.2 Heat Rate

Heat rate values in 2010 for fossil, nuclear, biomass, and geothermal technologies are shown in Table 7. In most data sets, heat rates remain constant over the modeling horizon or show a modest improvement (see following data set sections in this report for details on heat rate changes over time).

Table 7. Heat Rate Values by Data Set (Btu/kWh, for 2010)[11]

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	9,200	---	9,200	9,319	9,200	8,979	123	1%
IGCC	8,765	---	9,000	8,005	8,765	8,979	406	5%
Combustion Turbine	9,289	---	8,900	8,877	9,289	---	231	3%
Combined Cycle	6,752	---	6,870	6,164	6,752	7,260	393	6%
Nuclear	10,434	---	10,400	10,339	10,434	10,339	48	0%
Biomass	9,646	---	14,500	12,133	9,646	12,186	2,042	18%
Geothermal	34,633	---	---	34,120	---	---	363	1%

The heat rate values in Table 7 are shown in Figure 2 along with the coefficient of variation. The CV values are below 20% for all six technologies, and below 10% for six of the seven technologies.

The two technologies with large CV values are combustion turbines (13%) and biomass (18%). For biomass, the NREL-SEAC data set is at the high end of the heat rate range, and the AEO and EPA data sets are at the low end of the heat rate range.

[11] For some technologies in some data sets, the online year occurs after 2010. In these cases, the heat rates correspond to the on-line year.

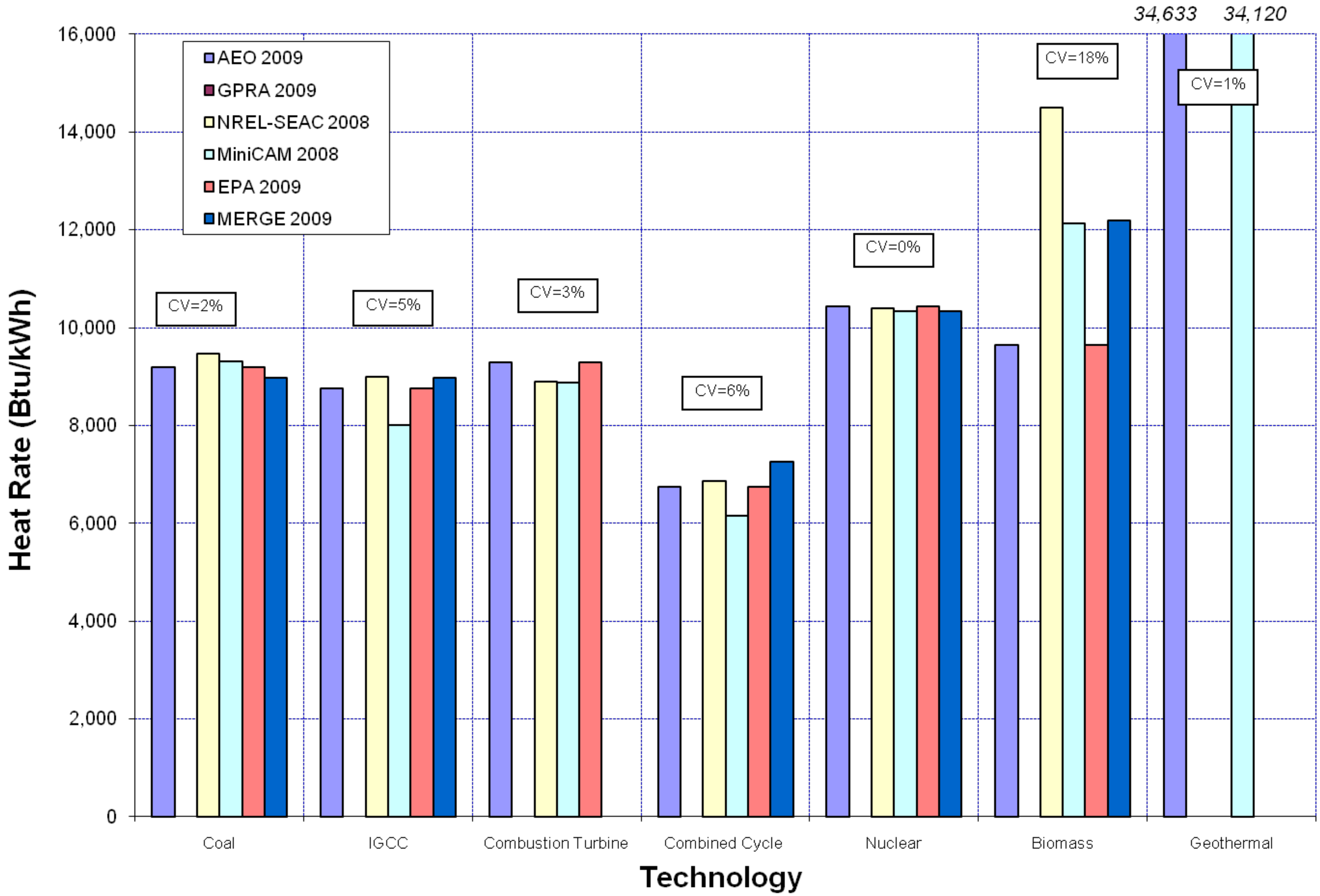


Figure 2. Heat rate comparisons

2.3 Availability Factor (Capacity Factor)

Capacity factors are often outputs in energy-economic models, based on estimated generation and taking into account any curtailment that is necessary. The maximum availability factor is generally the input to the model and represents the highest possible capacity factor. AEO 2009 and MiniCAM 2008 wind and solar data represent capacity factors from model outputs, whereas other data sets represent maximum availability factors for wind and solar technologies. Data for conventional, biomass, and geothermal technologies from all data sets are maximum availability factors. Capacity factors and availability factors are used interchangeably throughout the report, as generally the capacity factor is very close or equal to the maximum availability factor. An important exception to this is when models utilize supply curves for renewable technologies where the quality of the resource is highly variable and depends upon the location of the facility. Technologies that make use of geothermal, wind, and solar resources are often modeled using a supply curve. In a supply curve, there is a limited amount of development that may occur in any resource class, and each resource class has an associated capacity factor. For AEO 2009 and MiniCAM 2008 data, the reported capacity factors for wind and solar technologies represent average capacity factors of all installations estimated in model outputs. EPA 2009 and MERGE 2009 data represent average national capacity factor inputs, whereas GPRA 2009 and NREL-SEAC 2008 data represent capacity factor inputs from particular classes within a supply curve.

Capacity factors for 2010 are shown in Table 8 and Figure 3 (or the closest year in the data set).[12] For combustion turbines, the MiniCAM data has a significantly lower availability factor compared to other data sets (10%). This value is closer to the resulting capacity factor for all data sets for combustion turbine technologies.

Table 8. Capacity Factors for 2010

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	85%	---	85%	80%	85%	80%	0.027	3%
IGCC	85%	---	81%	80%	85%	80%	0.026	3%
Combustion Turbine	92%	---	88%	10%	92%	---	0.404	57%
Combined Cycle	87%	---	85%	80%	87%	80%	0.035	4%
Nuclear	90%	---	90%	90%	89%	90%	0.004	0%
Biomass	83%	---	84%	80%	83%	85%	0.019	2%
Geothermal (hydrothermal)	90%	95%	85%	90%	87%	---	0.039	4%
Wind (onshore)[13]	44%	43%*	43%*	42%	39%	35%	0.034	8%
Wind (offshore)[14]	40%	36%*	45%*	---	---	---	0.045	11%
Solar Thermal[15]	31%	42%+	32%[16]	73%+	36%	22%	0.178	45%
PV	22%	23%	21%	25%	24%	26%	0.019	8%

[12] If the technology online year occurs after 2010, the table shows the capacity factor for the online year, not 2010.
[13] "*" indicates a Class 5 wind resource was used. Otherwise, a national average capacity factor was used.
[14] "*" indicates a Class 5 wind resource was used. Otherwise, a national average capacity factor was used.
[15] "+" indicates thermal energy storage is included
[16] Class 4 solar thermal resource

The capacity factors for solar thermal technologies are interesting from the perspective that MiniCAM and GPRA incorporate thermal storage, whereas the other four data sets do not. Thermal storage is the reason for the relatively high (73%) capacity factor in the MiniCAM data set. In the MiniCAM data set, the level of thermal storage is assumed to be constant over time (i.e., MiniCAM solar thermal capacity factor remains constant at 73% over time). However, in the GPRA data set the level of thermal storage increases over time, which leads to an increase in the solar thermal capacity factor over time. In GPRA, the solar thermal capacity factor doubles between 2007 (41%) and 2030 (82%), with intermediate values of 42% in 2010 and 74% in 2025.

For PV, the capacity factors range from 21% to 26% with a standard deviation of 0.019 (8% coefficient of variation). The NREL-SEAC data set has the lowest PV capacity factor (21%), and the MERGE data set has the highest capacity factor (26%).

Capacity factors for the year 2025 are shown in Table 9 and Figure 4, and changes relative to 2010 are shown in Table 10. Fossil and nuclear technology capacity factors show little or no change between 2010 and 2025. However, renewable technology capacity factors increase in several cases between 2010 and 2025. One interesting observation is that the capacity factor for onshore wind in the AEO data set actually declines between 2010 and 2025 (from 44% to 40%). For the AEO data set, capacity factors are endogenous variables that are generated by the NEMS model. In the case of onshore wind technologies, NEMS is forecasting a decline in capacity factors, perhaps due to the development of lower quality wind resources in later years.

Table 9. Capacity Factors for 2025

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	85%	---	85%	80%	85%	80%	0.027	3%
IGCC	85%	---	81%	80%	85%	80%	0.026	3%
Combustion Turbine	92%	---	80%	10%	92%	---	0.394	58%
Combined Cycle	87%	---	85%	80%	87%	80%	0.035	4%
Nuclear	90%	---	90%	90%	89%	90%	0.003	0%
Biomass	83%	---	84%	80%	83%	85%	0.019	2%
Geothermal (hydrothermal)	90%	95%	85%	90%	87%	---	0.039	4%
Wind (onshore)[17]	40%	47%*	46%*	46%	39%	42%	0.035	8%
Wind (offshore)[18]	40%	45%*	48%*	---	---	---	0.038	9%
Solar Thermal[19]	31%	74%	32%[20]	73%	36%	22%	0.229	51%
PV	22%	32%	21%	25%	24%	26%	0.037	15%

[17] "*" indicates a Class 5 wind resource was used. Otherwise, a national average capacity factor was used.
[18] "*" indicates a Class 5 wind resource was used. Otherwise, a national average capacity factor was used.
[19] "+" indicates thermal energy storage is included
[20] Class 4 solar thermal resource

Table 10. Capacity Factor Changes in 2025 Relative to 2010

	Data Set					
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**
Coal	0%	---	0%	0%	0%	0%
IGCC	0%	---	0%	0%	0%	0%
Combustion Turbine	0%	---	0%	0%	0%	---
Combined Cycle	0%	---	0%	0%	0%	0%
Nuclear	0%	---	0%	0%	0%	0%
Biomass	0%	---	0%	0%	0%	0%
Geothermal (hydrothermal)	0%	0%	0%	0%	0%	---
Wind (onshore)	-10%	9%	6%	10%	0%	20%
Wind (offshore)	0%	25%	6%	---	---	---
Solar Thermal	0%	79%	0%	0%	0%	0%
PV	0%	36%	0%	0%	0%	0%

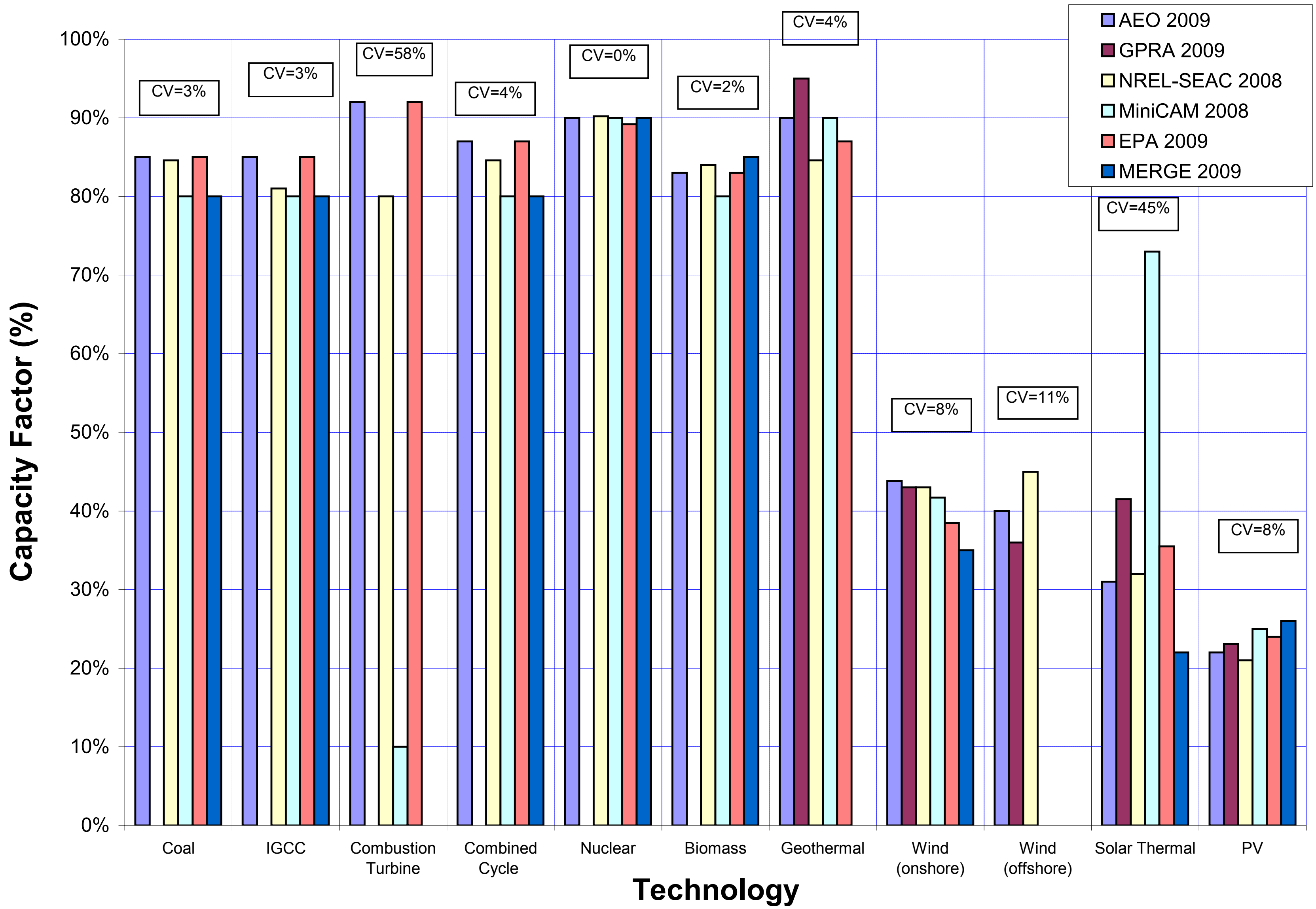


Figure 3. 2010 Capacity factor comparison

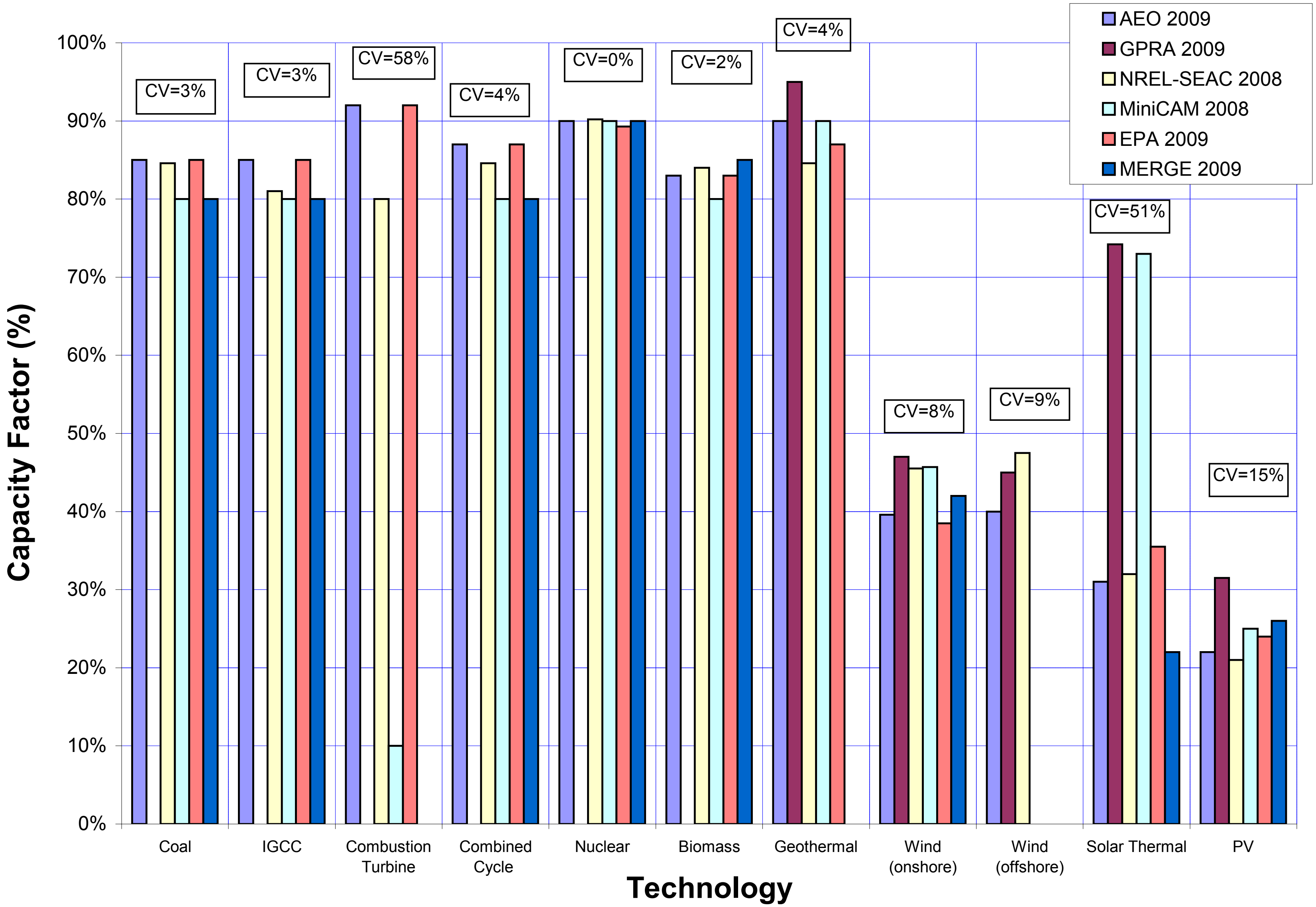


Figure 4. 2025 Capacity factor comparison

2.4 Plant Lifetime

Plant lifetimes are shown in Table 11, and in Figure 5. It can be difficult to draw conclusions when comparing lifetimes. For example, some data sets, such as AEO and EPA do not use plant lifetimes. The models supported by these two data sets – NEMS and IPM, respectively – allow plants to run for as long as they are economic, with no pre-determined retirement age. In some data sets, lifetimes represent the maximum service life, whereas in other models, the reported lifetime is the value used to compute economic results, such as the levelized cost of energy (LCOE) or for retirement calculations.

Table 11. Plant Lifetime (years)

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**[21]	**Standard Deviation**	**Coefficient of Variation**
Coal	X	---	60	45	X	30	15.0	33%
IGCC	X	---	60	45	X	30	15.0	33%
Combustion Turbine	X	---	30	45	X	---	10.6	28%
Combined Cycle	X	---	30	45	X	30	8.7	25%
Nuclear	X	---	60	60	X	30	17.3	35%
Biomass	X	---	45	45	X	30	8.7	22%
Geothermal (hydrothermal)	X	+	20	30	X	---	7.1	28%
Wind (onshore)	X	20	20	30	X	30	5.8	23%
Wind (offshore)	X	20	20	---	---	---	0.0	0%
Solar Thermal	X	30	30	30	X	30	0.0	0%
PV	X	30	30	30	X	30	0.0	0%

--- Technology not included in data set
X Technology included in data set, but lifetime not pre-determined
+ Technology included in data set, but lifetime not reported

A few general trends, though, can be discerned regarding plant lifetimes.

- Renewable technologies – geothermal, wind, and solar – have lifetimes in the range of 20 to 30 years.
- Fossil plants have lifetimes in the range of 30 to 60 years.
- Nuclear plants in most data sets have a lifetime of 60 years (30-40 year initial license plus one 20-30 year license renewal).
- In the MERGE data set, all plants are assumed to have an economic life of 30 years. These 30-year plant lifetime values are for economic calculations, and are not intended to reflect service lifetimes.

[21] MERGE plant lifetimes represent economic lifetimes, not service lifetimes

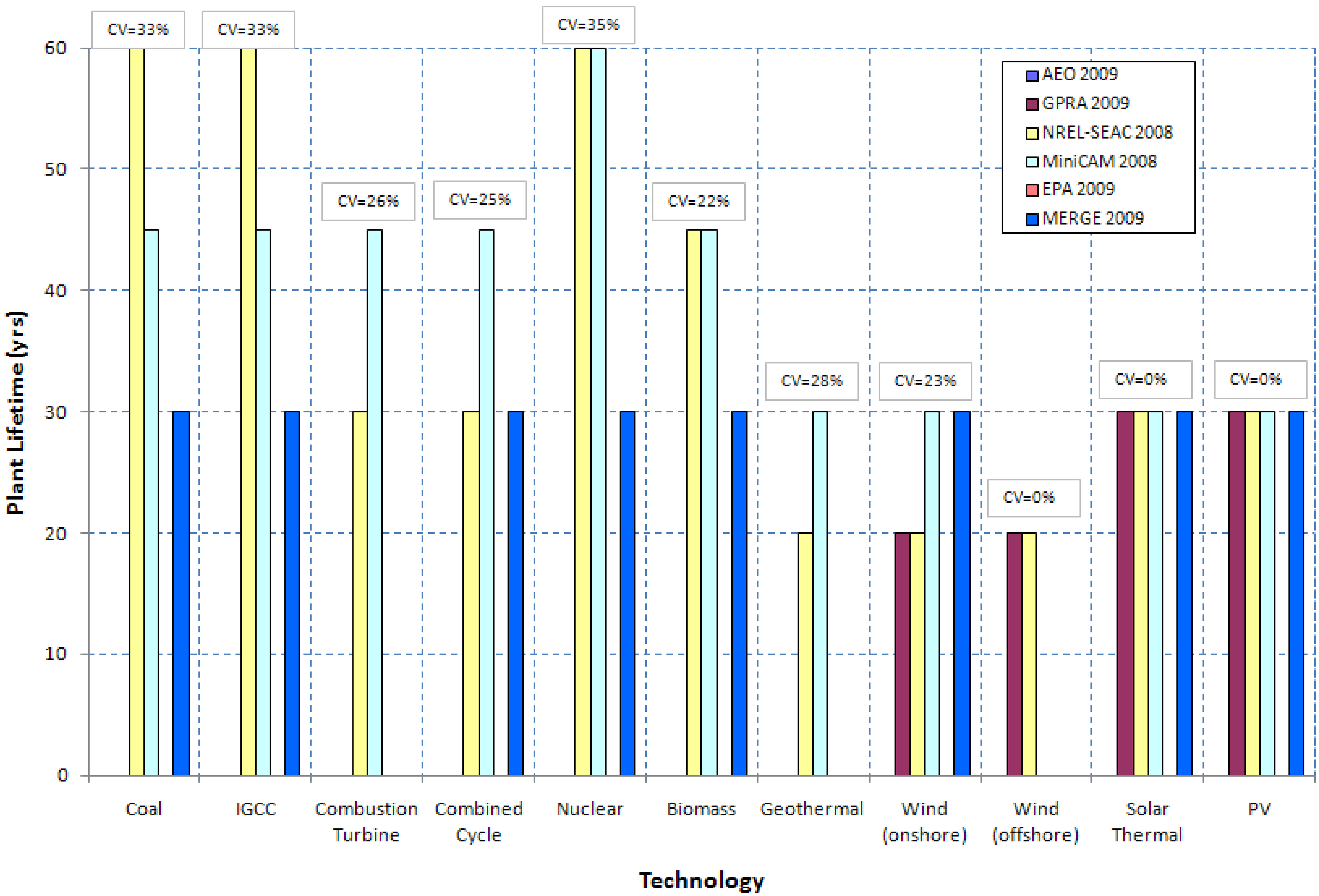


Figure 5. Plant lifetime comparison

3 Cost Characteristics

The comparison of cost characteristics is organized as follows:

- Overnight Capital Costs[22]
- Learning
- O&M Costs (fixed and variable)

For cost comparisons, the capital and O&M costs in all data sets have been adjusted to 2007 dollars using the GDP index shown in Appendix H.

3.1 Capital Cost

The overnight capital costs for the 11 technologies in the six data sets are presented in the following 11 graphs (Figure 6 through Figure 16). Each of the 11 technologies is included in a separate comparison chart. All costs have been adjusted to 2007 dollars. The following are a few observations concerning overnight capital costs in the following 11 figures:

- **Coal** – As indicated in Figure 6, MiniCAM is at the low end of the cost range. This result is likely because the MiniCAM characteristics are generally taken from the AEO 2008 publication (2007 calendar year data); while the other data sets generally have characteristics based on calendar year 2008 or 2009. There was a significant run-up in power plant costs starting in 2007, largely due to changes in commodity prices, and this cost increase is likely not captured in the MiniCAM data set.

  The capital costs for coal plants in the MERGE data set are at the high end of the range, and are held constant across the modeling horizon (indicative of no learning effects). The coal costs in the NREL-SEAC data set fall below the MERGE costs, but above the costs for all other data sets. As indicated in **Table 4**, the GPRA data set examined for this project does not include coal.
- **IGCC** – For IGCC plants (Figure 7), MiniCAM costs are at the bottom end of the range, and show declining costs over time (indicative of learning effects pushing costs downward over time). MERGE and NREL-SEAC are at the high end of the range, with NREL-SEAC costs trending slightly above MERGE overnight capital costs. Both the NREL-SEAC and MERGE data are relatively flat, showing no significant learning effects. The other data sets – AEO, MiniCAM, and EPA – all show noticeable declines in overnight capital costs over time. The GPRA data set does not include IGCC.
- **Combustion Turbine** – For combustion turbines (Figure 8), the NREL-SEAC data set has the highest overnight capital costs, and the MiniCAM data set generally has the lowest capital costs. For both NREL-SEAC and MiniCAM, the costs are

[22] Different data sets may have included different hardware for a particular technology, or used different definitions for "overnight capital costs." The level of detail provided with each data set did not allow us to thoroughly check all technologies and all definitions across all data sets. Overnight capital costs are shown as they are reported. Future analyses that compare overnight capital costs between data sets could be improved with a more detailed examination of technology descriptions and financial definitions used in the data sets being compared.

relatively constant over the modeling horizon (NREL-SEAC costs increase through 2010, and then remain constant). The other two data sets – AEO and EPA – both show declining combustion turbine costs over time. Starting in about 2025, AEO costs are less than or equal to MiniCAM costs. The GPRA and MERGE data sets do not include combustion turbines.

- **Combined Cycle** – For combined cycle plants (Figure 9), the MiniCAM data set has the lowest costs. The MiniCAM costs remain constant through 2020 (near $800/kW), then decline through 2050 (down to about $600/kW in 2050). The NREL-SEAC overnight capital costs start near the MiniCAM costs, but remain constant over the modeling horizon. The MERGE costs are higher (near $900/kW), and remain relatively constant over the modeling horizon. Compared to the other data sets, the AEO and EPA data sets do show noticeable declines in overnight capital costs starting in about 2015. The AEO costs are comparable to the MiniCAM costs in 2030 (around $700/kW). The GPRA data set does not include combined cycle.
- **Nuclear** – For nuclear plants (Figure 10), overnight capital costs fall in the range of approximately $2,500/kW to $4,800/kW. The MERGE data set is at the top end of the range, while the MiniCAM costs are towards the low end of the range. Costs in the AEO, NREL-SEAC and EPA data sets fall in between. Starting in about 2015, the AEO data set shows a decline in costs over time, with projected costs falling below $2,500 by 2030. The GPRA data set does not include nuclear.
- **Biomass** – Overnight capital costs for biomass technologies (Figure 11) are between approximately $2,000/kW and $4,000/kW. The MiniCAM costs are at the low end of the range, and the MERGE costs are at the high end over the entire time horizon. AEO and EPA costs start at the high end, but then fall, with AEO having costs below $2,500/kW by 2030. NREL-SEAC overnight capital costs are constant at slightly under $3,000/kW over the modeling horizon. The GPRA data set does not include biomass.
- **Geothermal** – The geothermal category shown in Figure 12 represents geothermal hydrothermal plants. As indicated, the EPA data set has an unusually high overnight capital – nearly $10,000/kW. However, this cost represents an average cost, and actual overnight costs for plants adopted each year could be significantly different. In the EPA data set, geothermal hydrothermal costs range from approximately $1,400/kW to over $17,000/kW depending on site-specific parameters. The value shown in Figure 12 is a simple average of these cost extremes. Data showing overnight capital costs for geothermal plants actually adopted each year in connection with the EPA 2009 data set were not available. Other than the EPA data set, overnight capital costs for geothermal plants fall between approximately $2,000/kW and $5,000/kW. Excluding the EPA data set, the GPRA costs are at the high end of the range, and the MiniCAM costs are towards the low end of the range. The AEO data set starts at a relatively low value (under $2,000/kW), and then rises sharply to nearly $5,000/kW before declining to about $3,000/kW. The sharp rise in geothermal overnight capital costs for the AEO data set results from the modeling approach used with this data set. For the AEO data set, there is an input list of identified available geothermal sites, with individual cost and performance characteristics for each site.

The NEMS model, which is run in conjunction with the AEO 2009 data set, adopts the least expensive site first. Once a specific geothermal site is selected to be built, it is removed from the list and the next most expensive geothermal site becomes available for adoption.

- **Wind (onshore)** – For onshore wind (Figure 13), the MERGE data set has overnight capital costs at the upper end, and the GPRA and MiniCAM data sets are at the low end. The AEO, NREL-SEAC, and EPA data sets are in between. With NREL-SEAC and AEO, the overnight capital costs decline over time, indicating that learning is having an impact. The EPA costs remain constant over time.
- **Wind (offshore)** – Three data sets – AEO 2009, NREL-SEAC 2008, and GPRA 2009 – have offshore wind (Figure 14). Overnight capital costs for AEO 2009 are at the upper end, starting slightly below \$4,000/kW in 2007, and then falling below \$3,000/kW by 2030. The GPRA cost curve starts slightly below \$3,000/kW, and then declines relatively quickly crossing the NREL-SEAC cost curve in 2014. From 2030 and beyond, the GPRA cost is near \$1,500/kW. The NREL cost curve starts near \$2,500/kW in 2005, and declines to approximately \$2,200/kW by 2050.
- **Solar Thermal** – In 2005 (Figure 15), the NREL-SEAC data set has an overnight capital cost for solar thermal near \$6,500/kW. The NREL-SEAC cost curve declines relatively quickly, reaching costs comparable to the other data sets by 2015. From approximately 2015 and beyond, the NREL-SEAC, EPA, and MERGE data sets have constant costs (i.e., no learning) in the range of \$4,500/kW to \$5,000/kW. The AEO, GPRA, and MiniCAM data sets all show declining costs. Between 2025 and 2030 (end year for AEO), the AEO and GPRA data sets trend closely, and reflect the lowest overnight capital costs (reaching about \$3,000/kW in 2030). From 2030 to 2050, the GPRA data set has the lowest costs, with the MiniCAM costs trending slightly higher. Solar thermal plants in MiniCAM and GPRA include thermal energy storage, while solar thermal plants in the other four data sets do not. It is interesting to note that the overnight capital costs for the AEO and GPRA data sets are quite close between 2025 and 2030, even though GPRA has thermal storage and AEO does not.
- **PV** – As seen in Figure 16, the GPRA and NREL-SEAC data sets have overnight capital costs that track relatively closely, with PV overnight capital costs in these two data sets consistently falling below PV costs in the other data sets. The MiniCAM PV overnight capital costs start above \$10,000/kW, but decline to about \$2,200/kW by the end of the modeling horizon (2050). The MERGE data set and the EPA data set each have constant costs – slightly under \$8,000/kW for MERGE and near \$5,800/kW for EPA. The AEO data set shows cost improvements over time – declining from around \$6,000/kW in the early years to below \$4,000/kW in 2030.

Table 12 summarizes the overnight capital cost trends in the six data sets. With the exception of the EPA and NREL-SEAC data sets, the data sets show similar cost trends for fossil fuel and renewable technologies. In the NREL-SEAC data set, capital costs for most fossil plants remain constant and capital costs for most renewable plants decline. Compared to the NREL-SEAC data set, the EPA data set generally shows different trends. In the EPA data set, capital costs for several fossil plants decline (or show up and down fluctuations), while capital costs for renewable plants typically remain constant.

As Table 12 shows, the AEO data set exhibits variable costs. The AEO data set includes a commodity cost adjustment based on a forecast of the metal and metal products producer price index. This index is forecast in the NEMS model, and it shows increasing capital costs over the next few years (through about 2015). This PPI forecast leads to cost increases in the early years (through about 2015) in the AEO 2009 data set. However, after the first few years, overnight capital costs for all technologies in the AEO data set decline as a result of learning effects.

Table 12. Capital Cost Trends by Data Set and Technology (11 technologies)

	Data Set					
Technology	**AEO 2009**	**GPRA 2009**	**NREL-SEAC 2008**	**MiniCAM 2008**	**EPA 2009**	**MERGE 2009**
Coal	⇳	---	⇳	⇩	⇩	O
IGCC	⇳	---	⇳	⇩	⇩	O
Combustion Turbine	⇳	---	⇳	⇳	⇳	---
Combined Cycle	⇳	---	O	⇩	⇳	⇳
Nuclear	⇳	---	⇩	⇩	O	⇩
Biomass	⇳	---	O	⇩	⇩	O
Geothermal (hydrothermal)	⇳	⇩	O	⇩	O	---
Wind (onshore)	⇳	⇩	⇩	⇩	O	O
Wind (offshore)	⇳	⇩	⇩	---	---	---
Solar Thermal	⇳	⇩	⇩	⇩	O	O
PV	⇳	⇩	⇩	⇩	O	O

--- technology not included in data set
O constant costs
⇩ declining costs
⇳ variable costs (cost trend shows rising, falling, and constant behavior over modeling horizon)

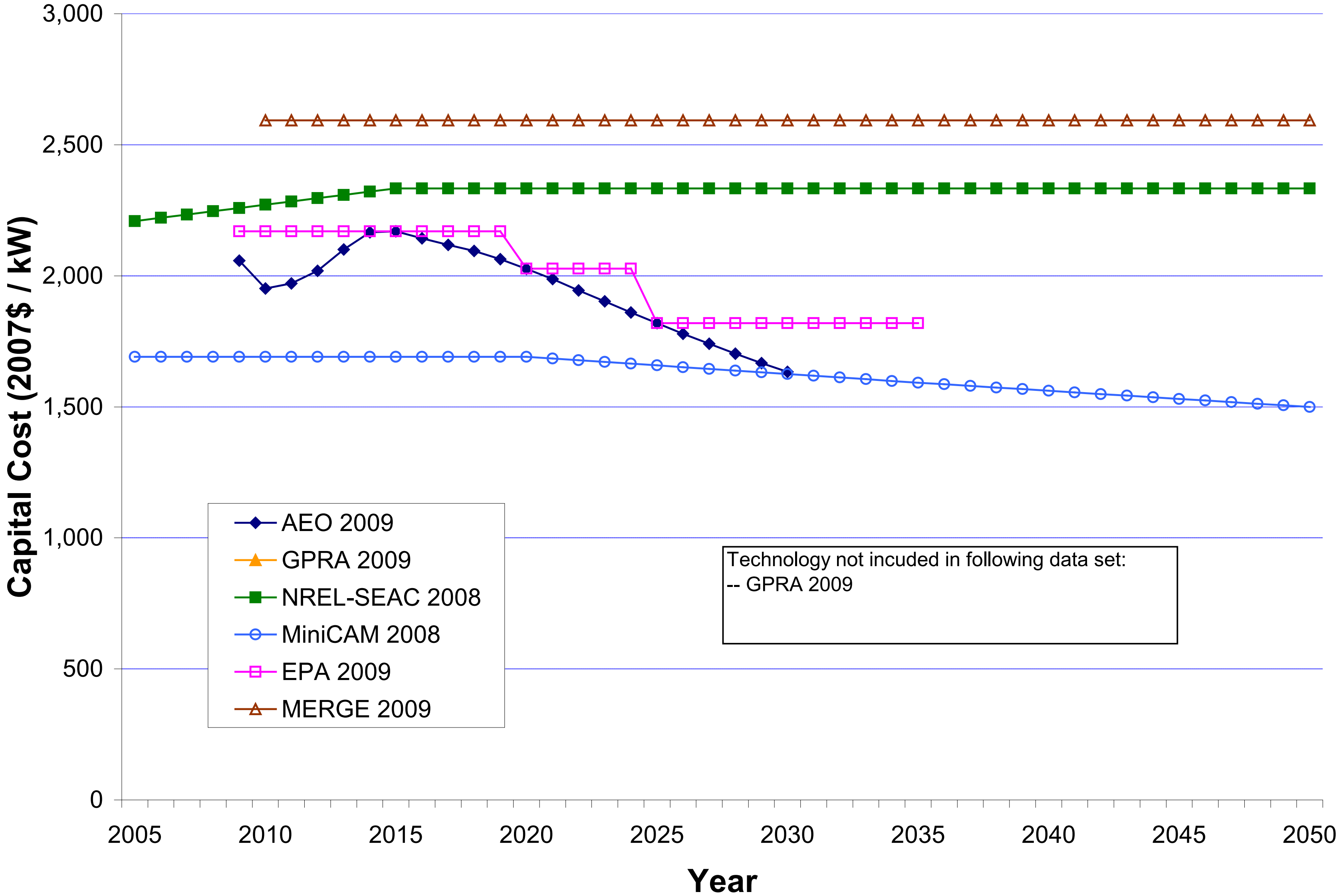


Figure 6. Overnight capital costs—coal

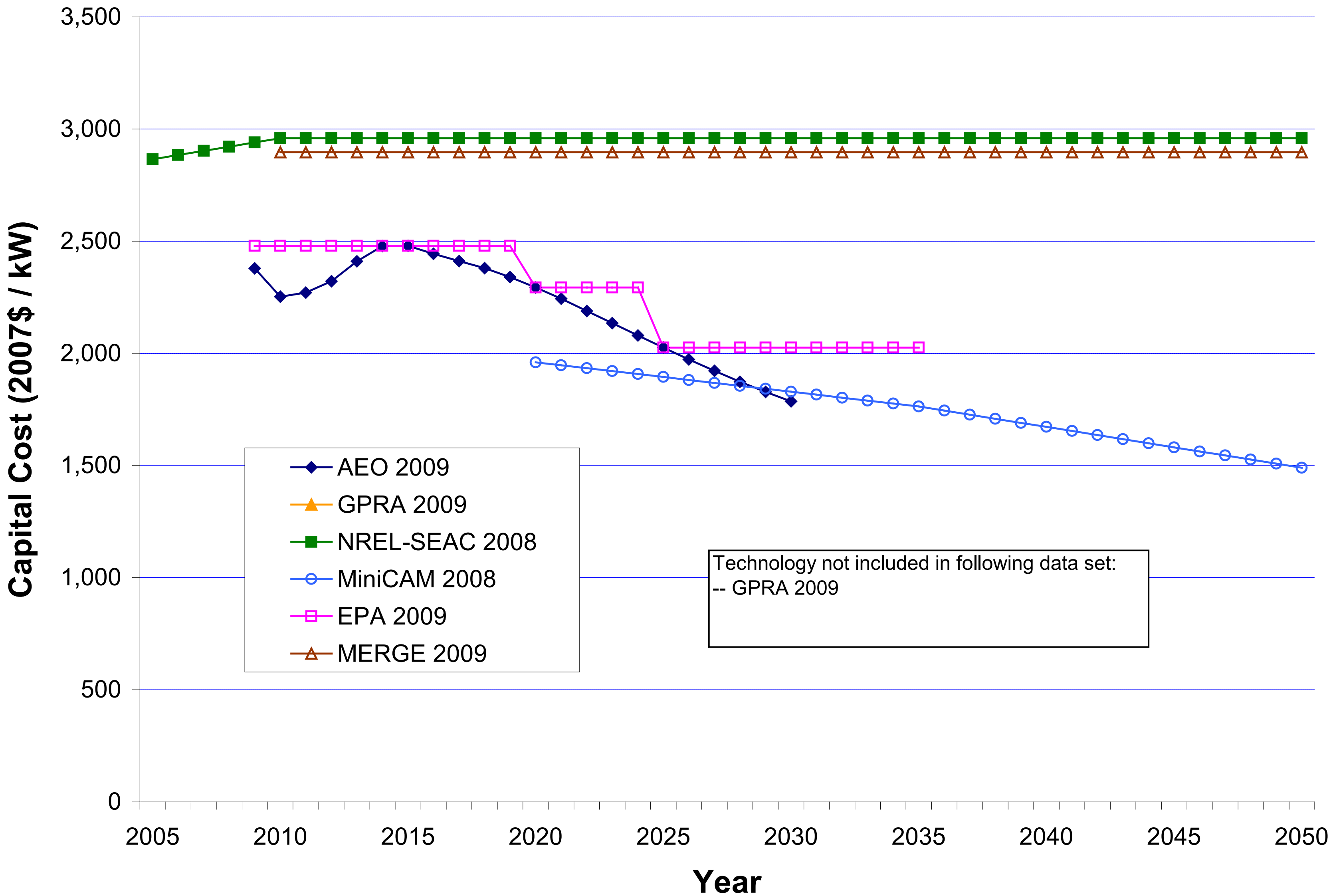


Figure 7. Overnight capital costs—IGCC

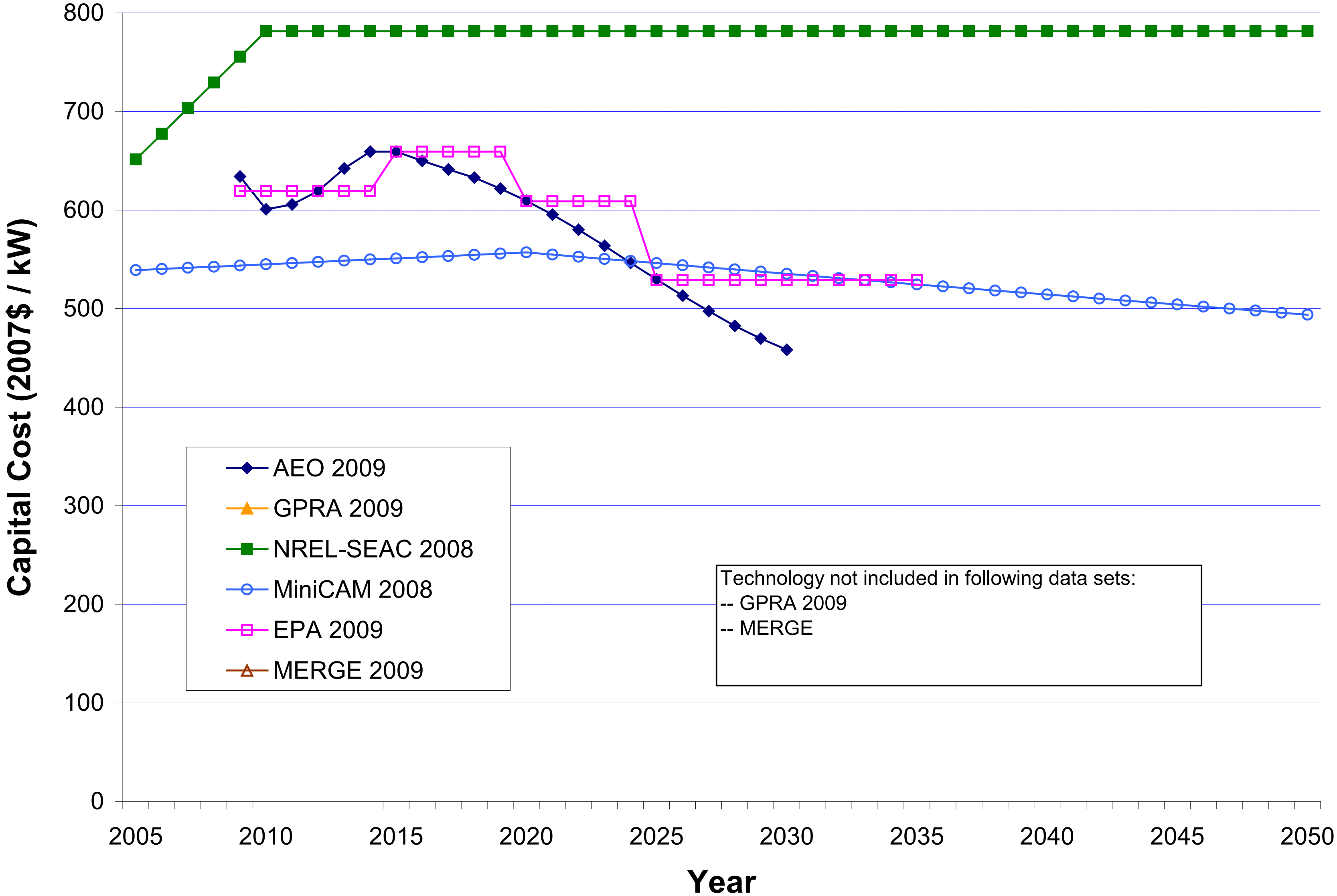


Figure 8. Overnight capital costs—combustion turbine

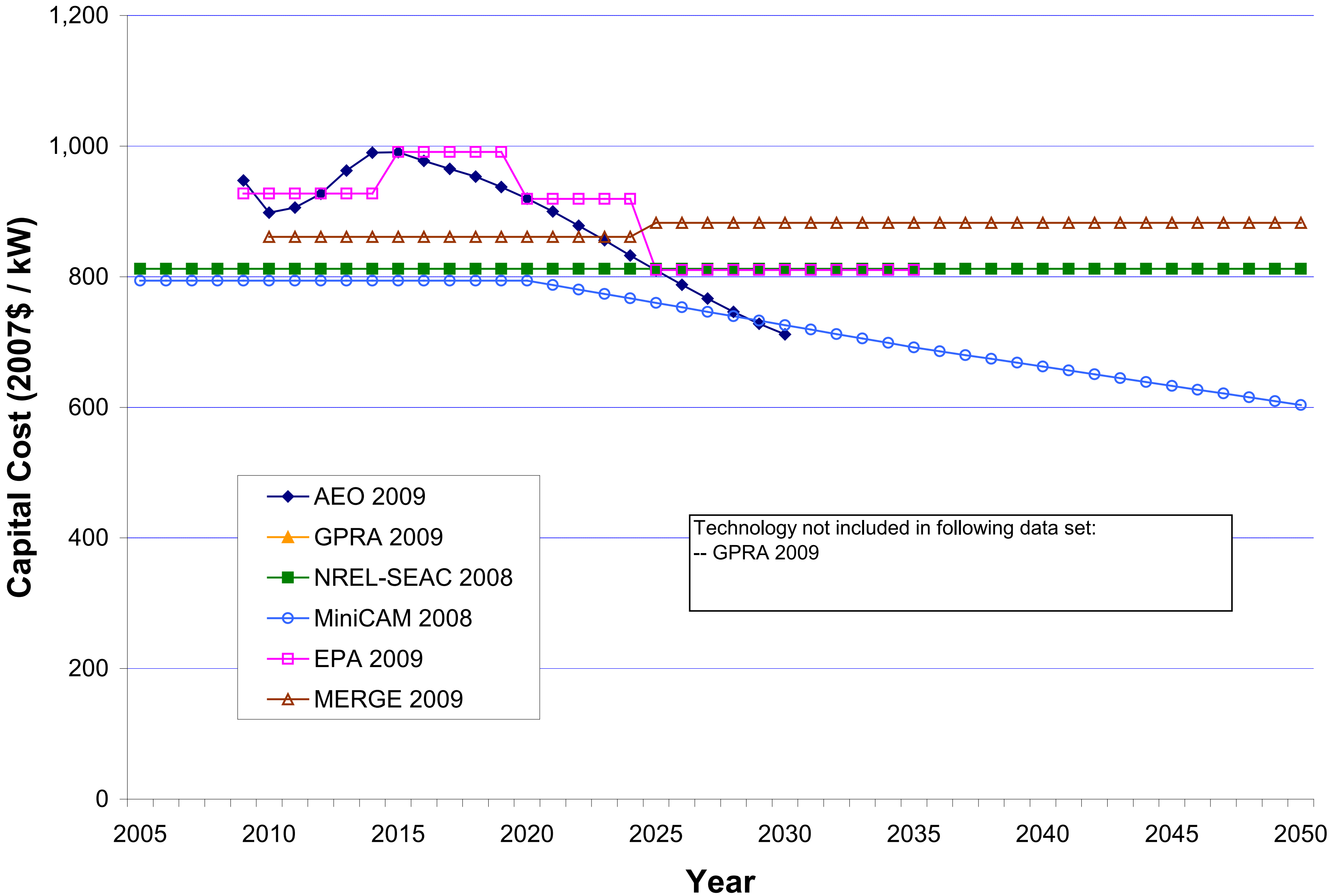


Figure 9. Overnight capital costs—combined cycle

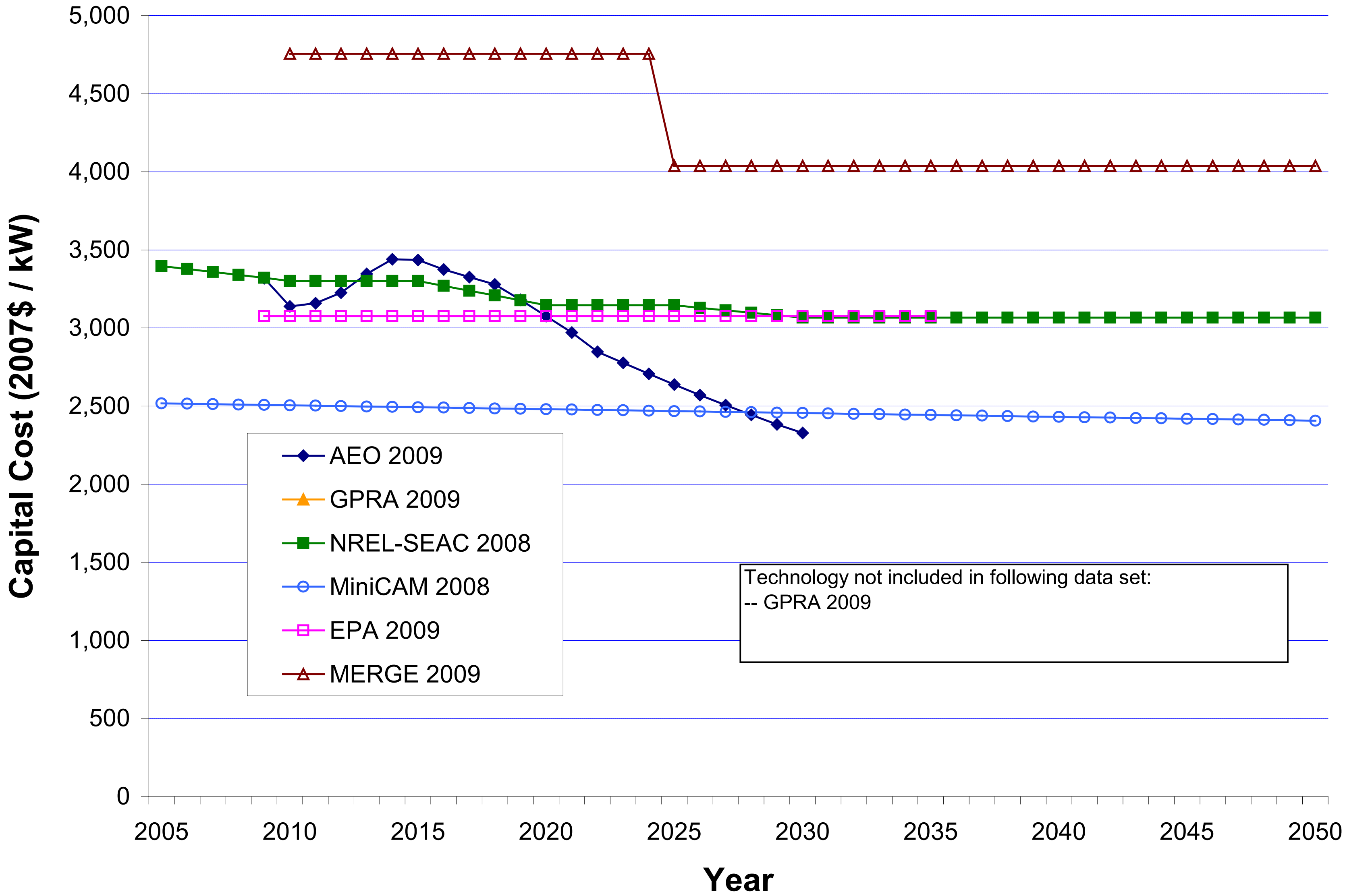


Figure 10. Overnight capital costs—nuclear

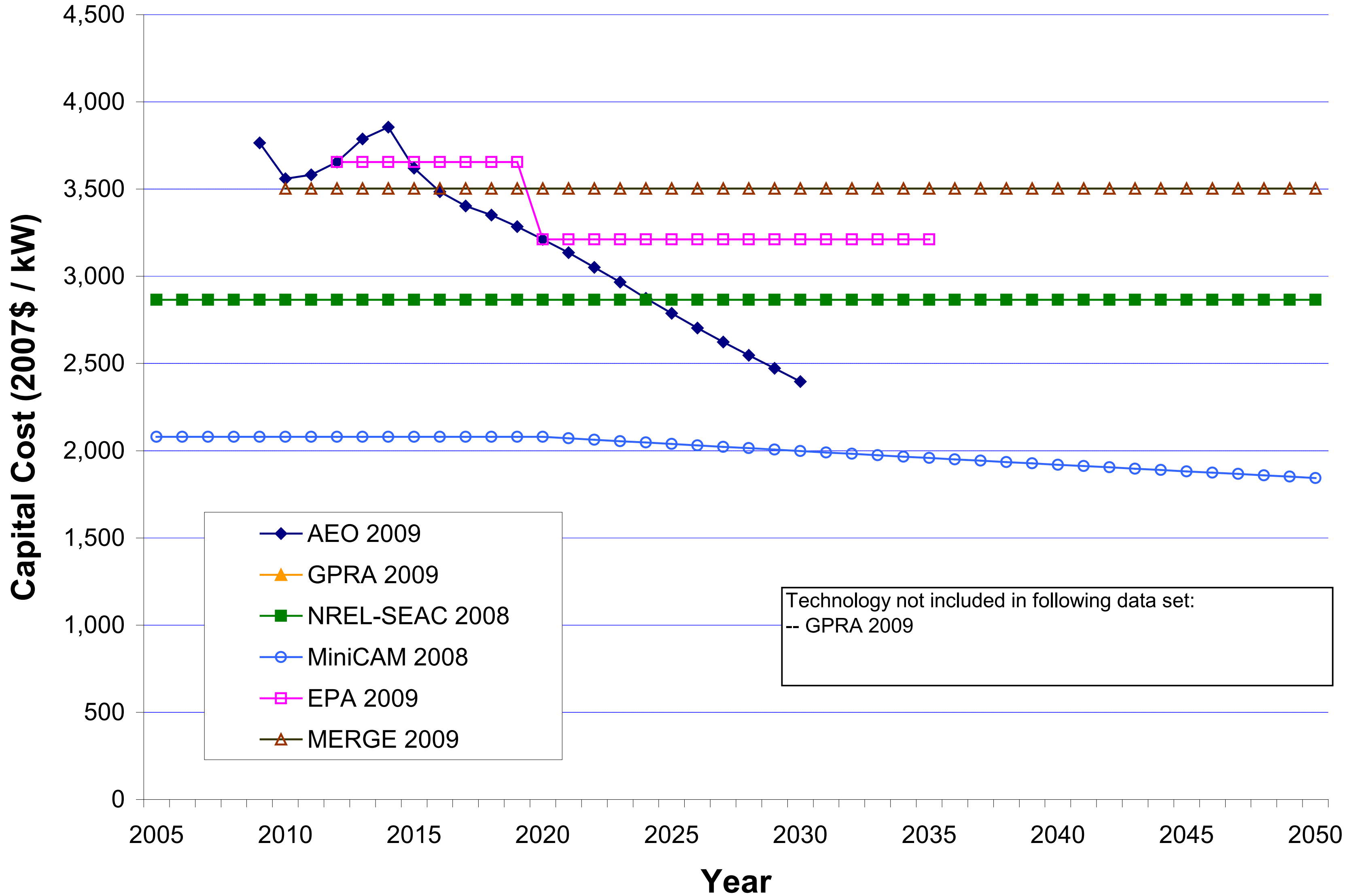


Figure 11. Overnight capital costs—biomass

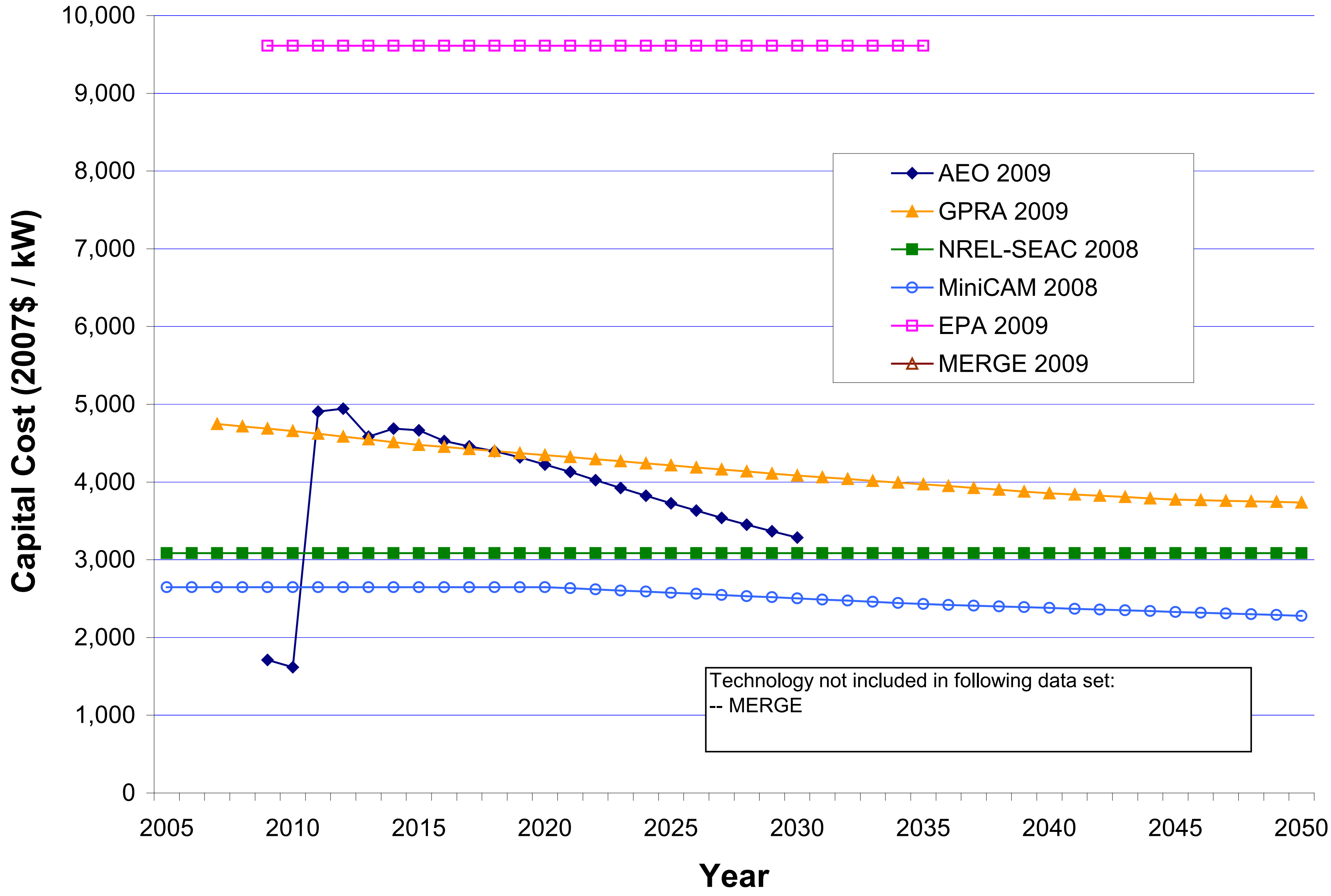


Figure 12. Overnight capital costs—geothermal

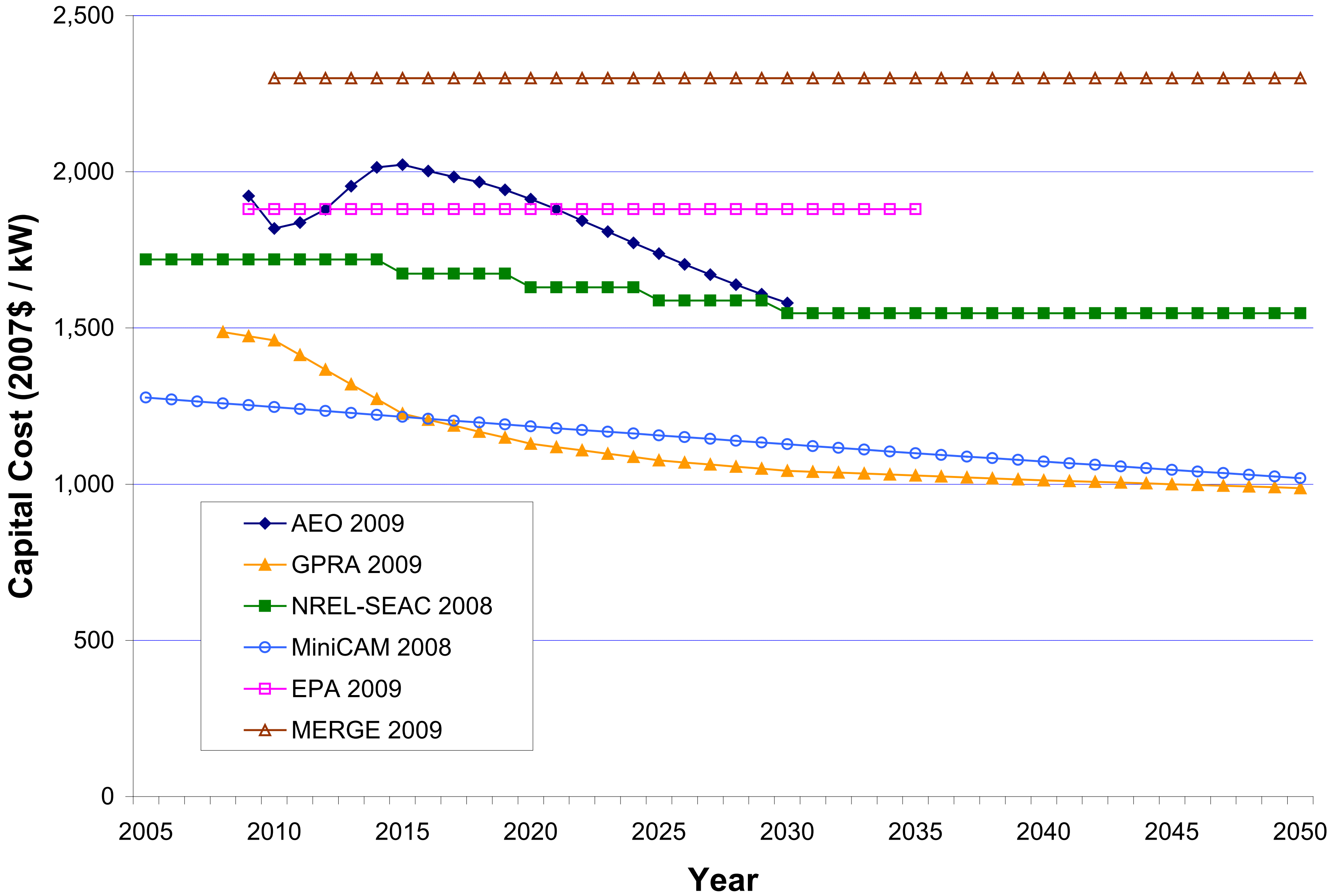


Figure 13. Overnight capital costs—wind (onshore)

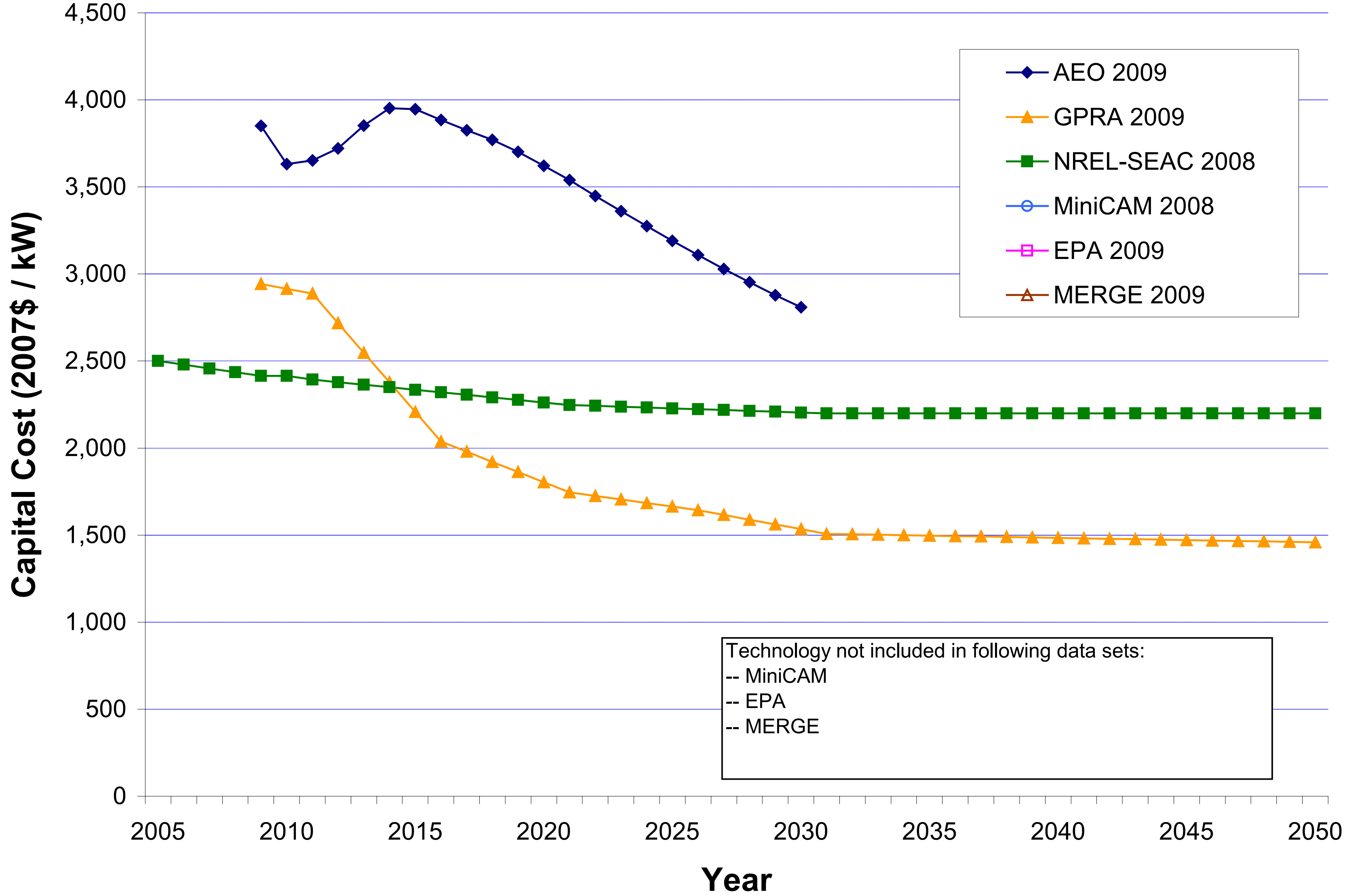


Figure 14. Wind (offshore)—overnight capital costs

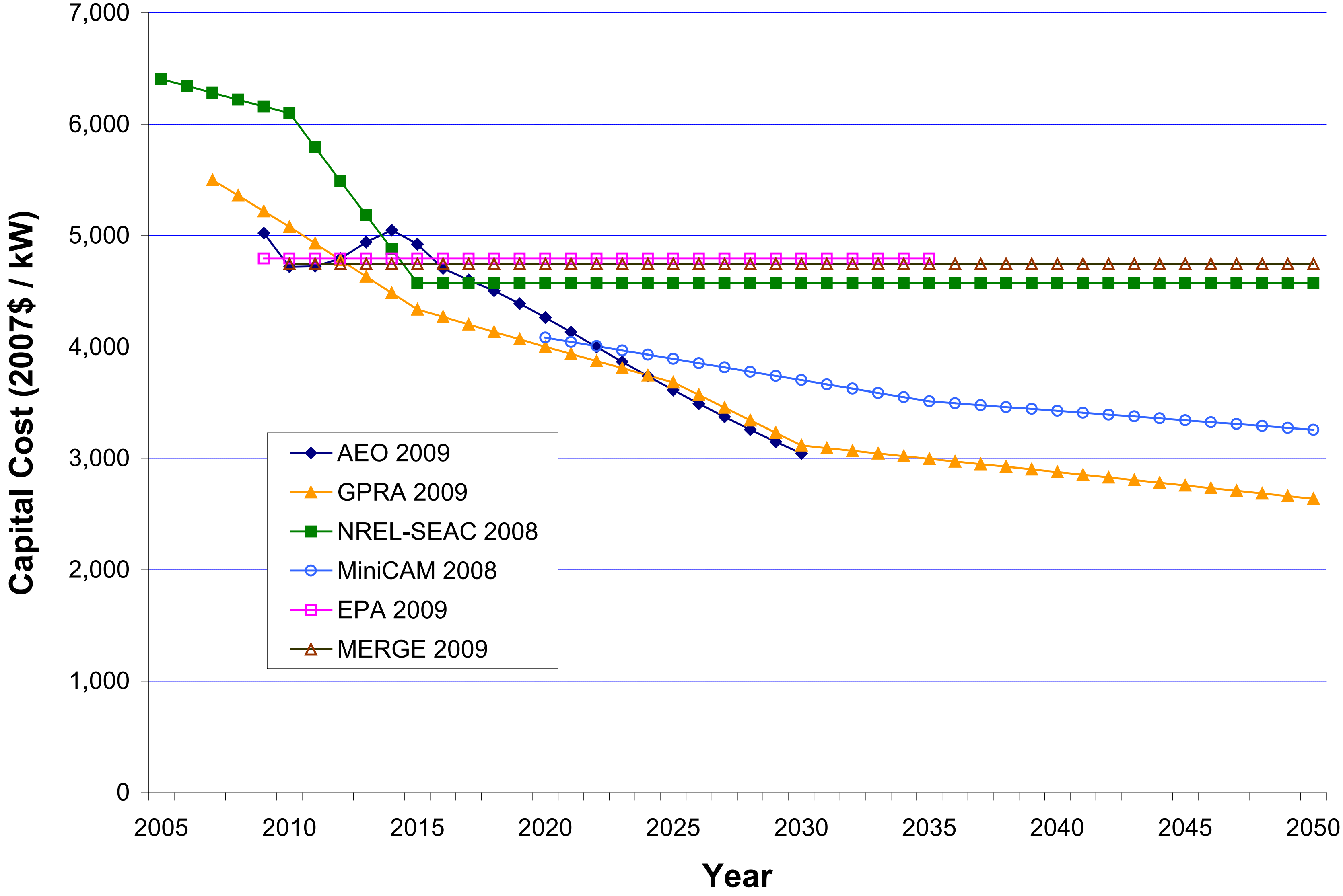


Figure 15. Overnight capital costs—solar thermal

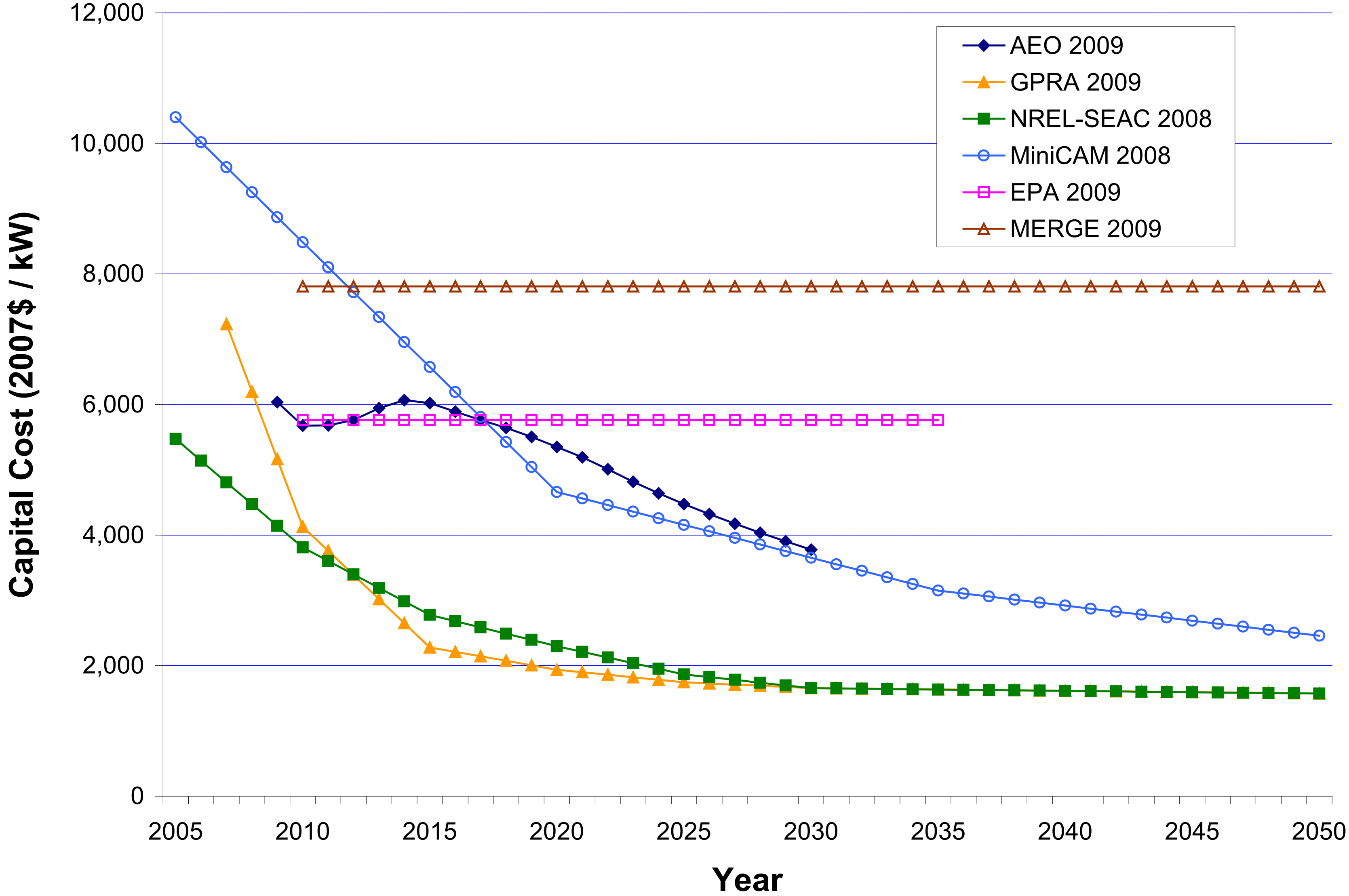


Figure 16. Overnight capital costs—PV

Table 13 shows the data sets with the highest and lowest capital costs in 2030. This table shows that the MERGE data set has the highest frequency of high overnight capital costs – highest, or tied for highest, for eight of the eleven technologies. The MERGE data set may have high costs because this data set generally shows no exogenous learning effects; instead, cost reductions occur in the model (not the data set) as certain expanded capacity thresholds have been reached.

Table 13. High and Low Capital Costs for Each Technology in 2030

Technology	Highest Capital Cost	Lowest Capital Costs
Coal	MERGE	AEO, MiniCAM (tied)
IGCC	NREL-SEAC, MERGE (tied)	AEO, MiniCAM (tied)
Combustion Turbine	NREL-SEAC	AEO
Combined Cycle	MERGE	AEO, MiniCAM (tied)
Nuclear	MERGE	AEO, MiniCAM (tied)
Biomass	MERGE	MiniCAM
Geothermal (hydrothermal)	EPA	MiniCAM
Wind (onshore)	MERGE	GPRA, MiniCAM (tied)
Wind (offshore)	AEO	GPRA
Solar Thermal	EPA, MERGE, NREL-SEAC (tied)	AEO, GPRA (tied)
PV	MERGE	GPRA, NREL-SEAC (tied)

The MiniCAM data set is at the low end of the cost spectrum in 2030 – lowest, or tied for lowest – for seven of eleven technologies. This observation is likely because the MiniCAM characteristics are generally taken from the AEO 2008 publication (2007 calendar year data), while the other data sets generally have characteristics based on calendar year 2008 or 2009. Although calendar year is not a direct indication of the year when the underlying data was derived, it can be used as a proxy for the vintage of the underlying data, which was not made available for MiniCAM and most other data sets. There was a significant run-up in power plant costs starting in 2007, largely due to changes in commodity prices, and these increases are likely not captured in the MiniCAM data set. After MiniCAM, the AEO data set has the highest frequency of low costs – five of eleven technologies. The AEO data set has relatively aggressive learning factors, and these high learning rates lead to relatively low capital costs for most technologies by 2030.

Another comparison of overnight capital costs is offered in Figure 17 and Figure 18. These figures show simple average costs for conventional technologies and renewables, respectively. The conventional technology group consists of four types of power plants: coal, IGCC, combined cycle, and nuclear (combustion turbines are not included in every data set, and are therefore omitted). The renewable group consists of three renewable technologies: onshore wind, solar thermal and PV (biomass, geothermal, and offshore wind are not included in every data set and are therefore omitted).

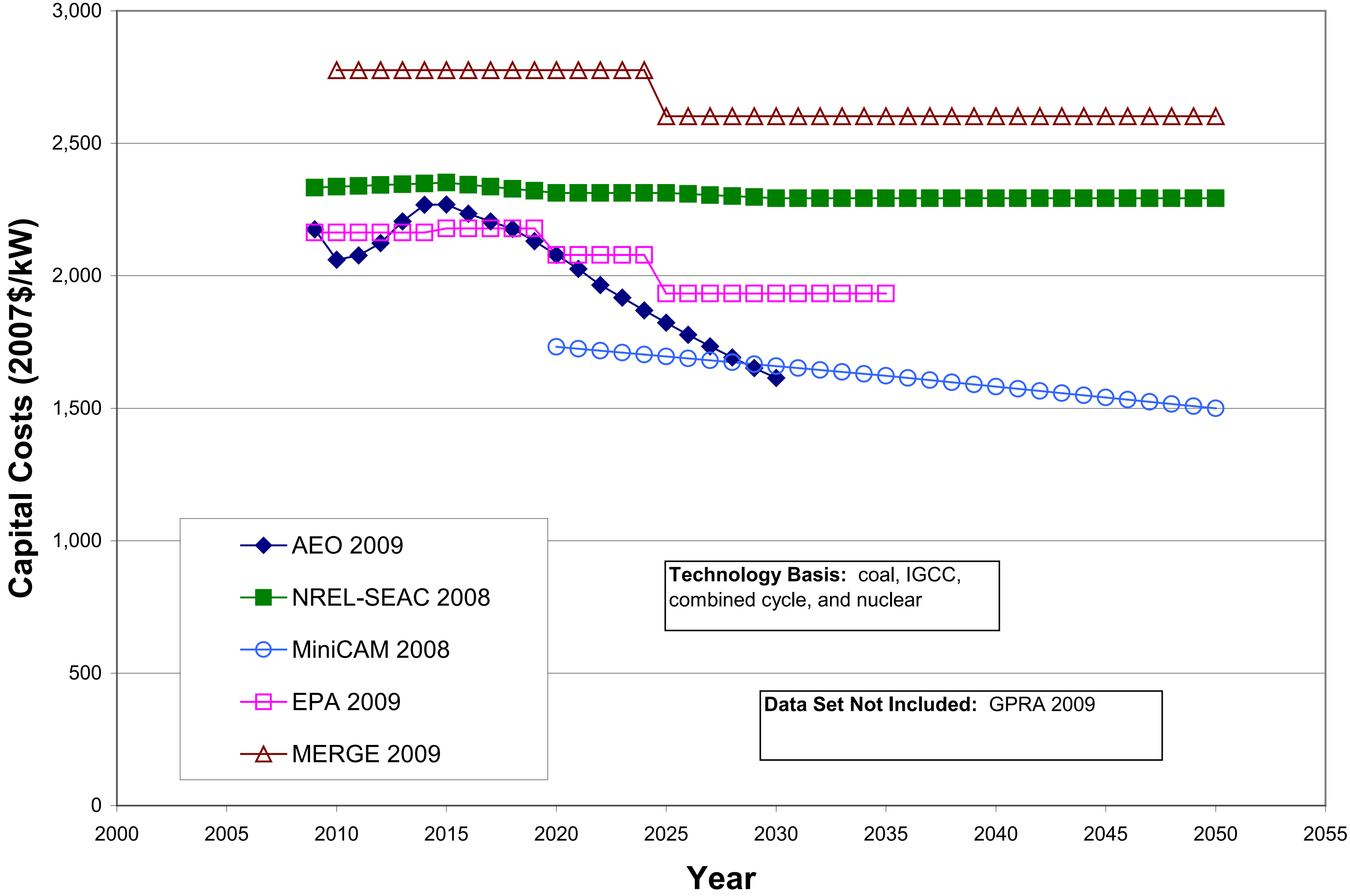


Figure 17. Average overnight capital costs—conventional technologies

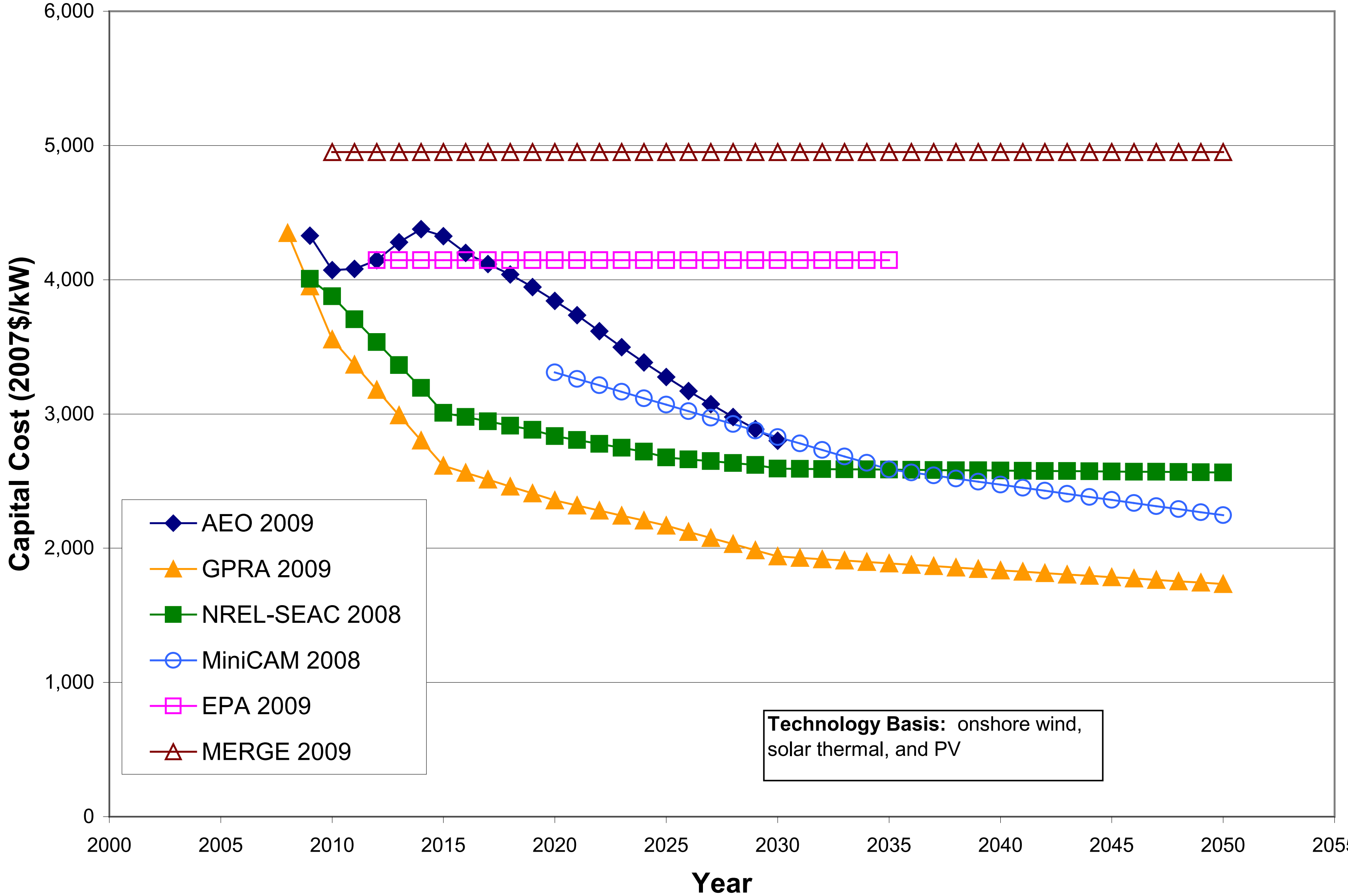


Figure 18. Average overnight capital costs—renewable technologies

The ratio of averaged renewable to conventional overnight capital costs is shown in Figure 19 (costs in Figure 18 divided by costs in Figure 17). This chart shows that the NREL-SEAC data set has the lowest differential between renewable and conventional costs. By 2025, the cost differential in the NREL-SEAC data set is reduced to 1.2, and by approximately 2035 the differential falls to 1.1 (i.e., the overnight capital cost of renewables is only 10% higher than conventional technologies). The EPA, MERGE, AEO and MiniCAM data sets all have higher costs differentials compared to the NREL-SEAC data set.

Scatter charts were prepared to examine the correlation between capital cost and plant size for 2010 and 2025. These charts are helpful in examining how costs are clustered, and how costs change over time (based on two years – 2010 and 2025).

The first scatter chart is shown in Figure 20, which shows capital costs and plant sizes in 2010. As indicated on the left hand edge of this figure, PV has relatively high costs, but it is also the smallest sized power generation technology compared. Moving up in capacity, onshore wind is the lowest cost technology for power plants with capacities near 100 MW. Combustion turbines are the lowest cost technology near 200 MW, and combined cycle plants are the lowest cost in the range of 300-450 MW. Nuclear is the only technology evaluated with capacities above 1,000 MW. To a certain extent, these observations are an artifact of the plant size ranges appearing in the various data sets. However, we know that new power plant construction in 2009 is dominated by onshore wind, combustion turbine, and combined cycle power plants, which is consistent with the overnight capital costs shown in Figure 20.

Figure 21 considers capital costs and plant sizes in 2025. Many of the cost points are somewhat lower in 2025 than in 2010, but the broad appearance of the scatter chart has not changed. The lowest cost plant technology for a given plant size has not changed over this time frame.

Scatter charts were also prepared to explore the correlation between capital cost and plant capacity factors for 2010 and 2025. The purpose of these charts is to anticipate the effect of capacity factors on the cost of energy. In general, the lowest levelized cost of energy (LCOE) will occur for capacity factors and low capital costs (the lower right corner of these charts).

Figure 22 considers the capital costs and capacity factors for 2010 (or the closest year in the data set). With the exception of the MiniCAM combustion turbine data point (which has a capacity factor corresponding to peaking power), the nuclear, biomass, and fossil fuel plants are at the right edge (high capacity factor). At low capacity factors, the technologies are stacked from lowest capital costs to highest capital costs in the following order: 1) onshore wind, 2) offshore wind, 3) solar thermal, and 4) PV.

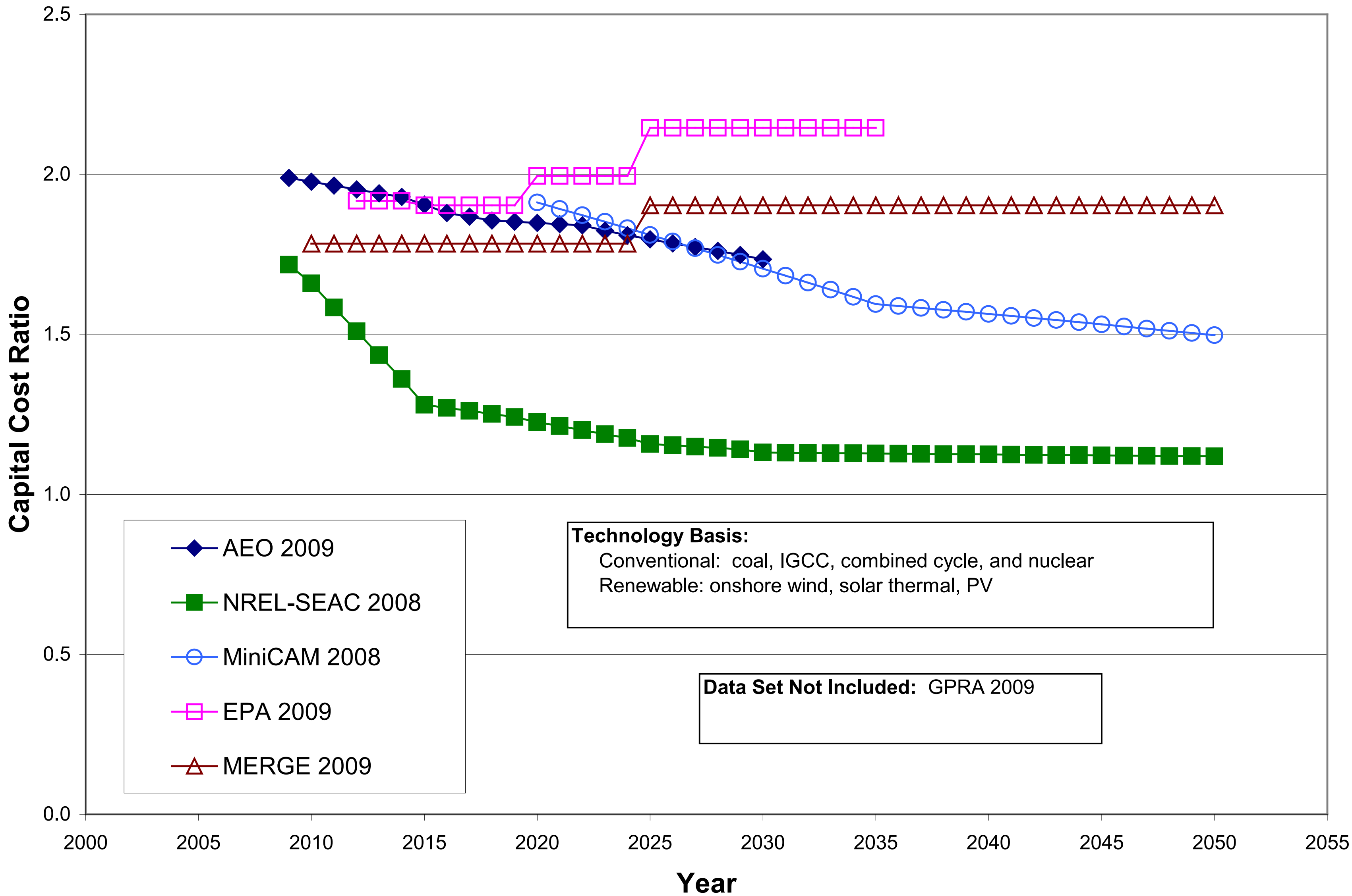


Figure 19. Ratio of average overnight capital costs (renewable/conventional)

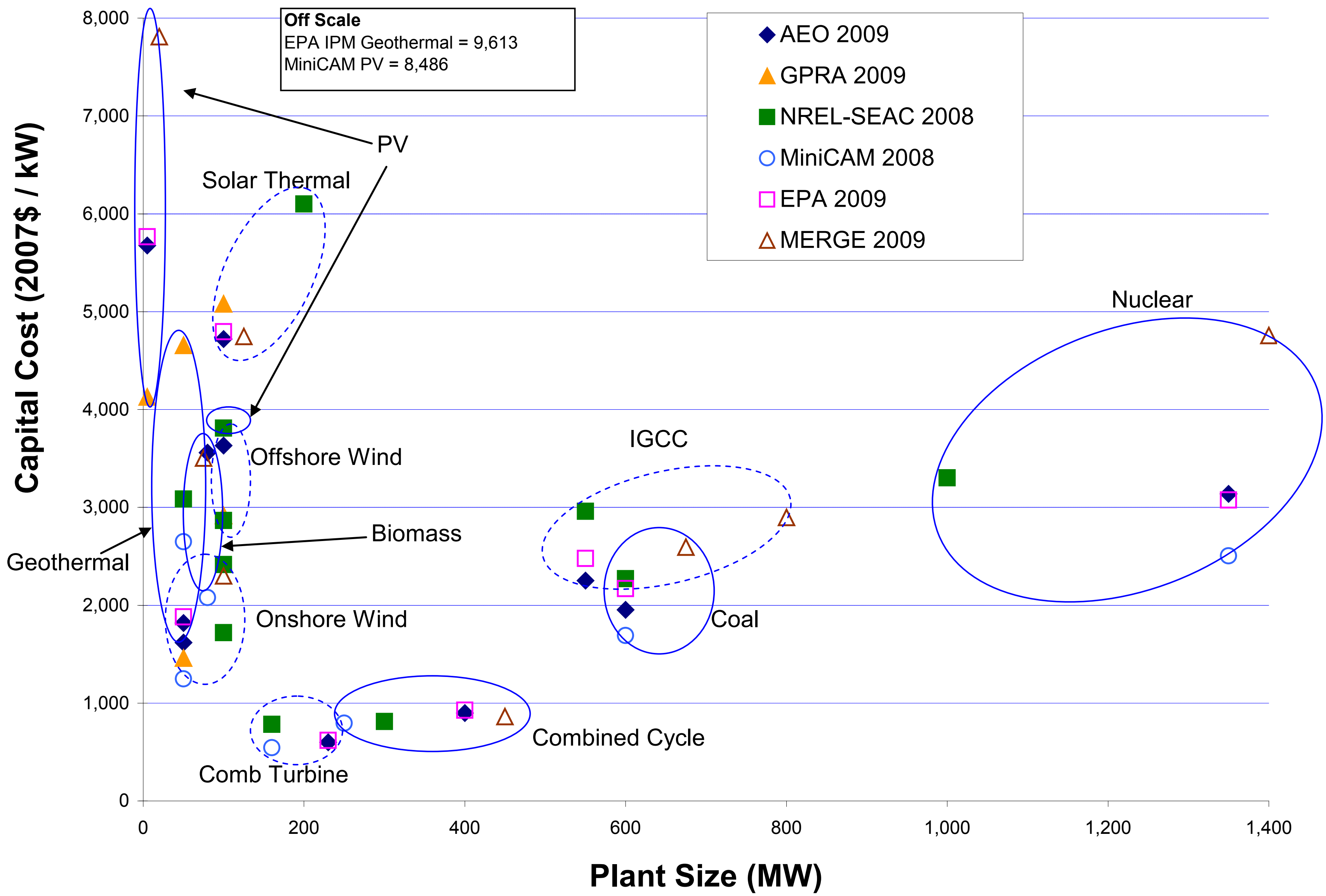


Figure 20. Capital cost versus plant size, 2010

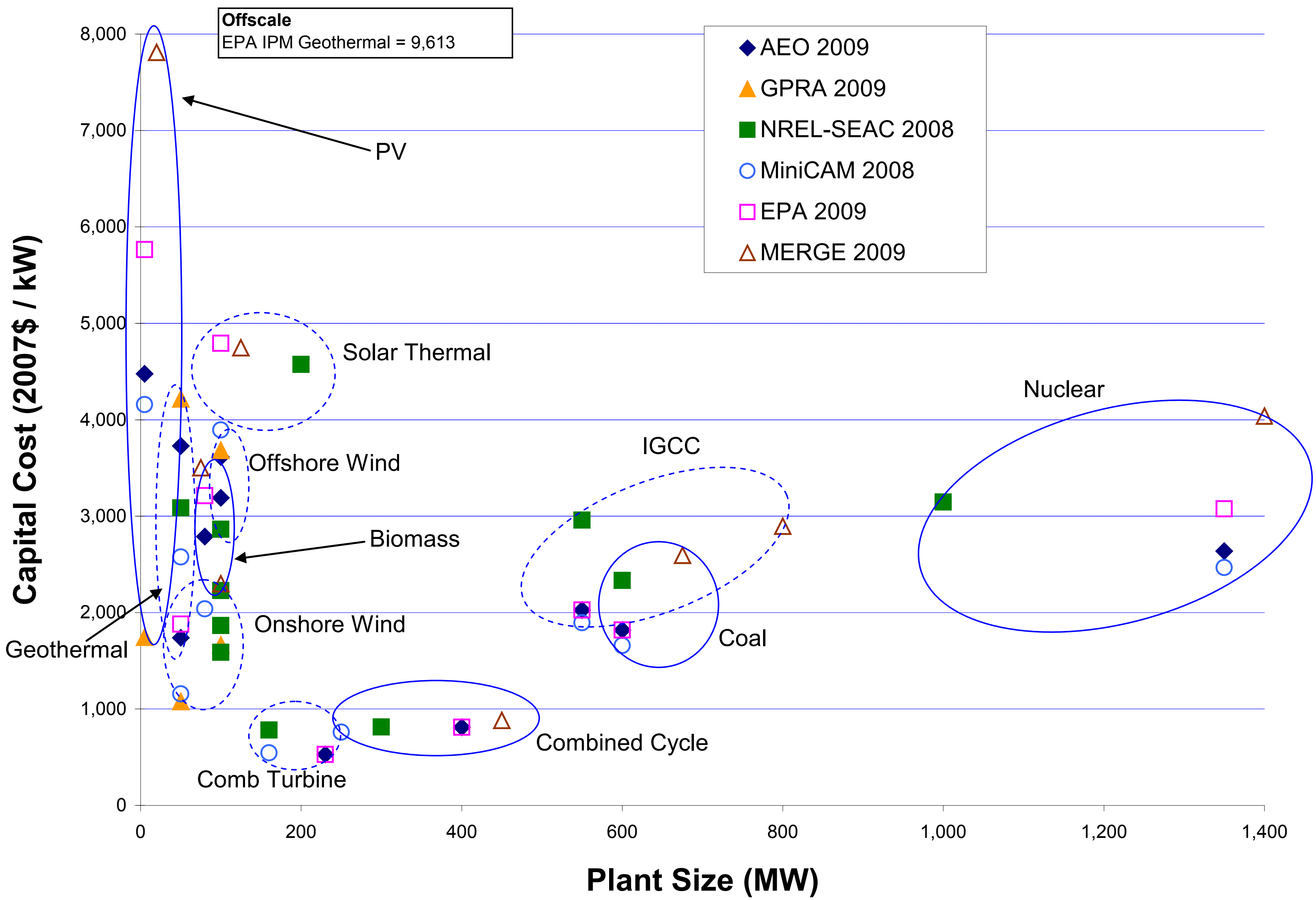


Figure 21. Capital cost versus plant size, 2025

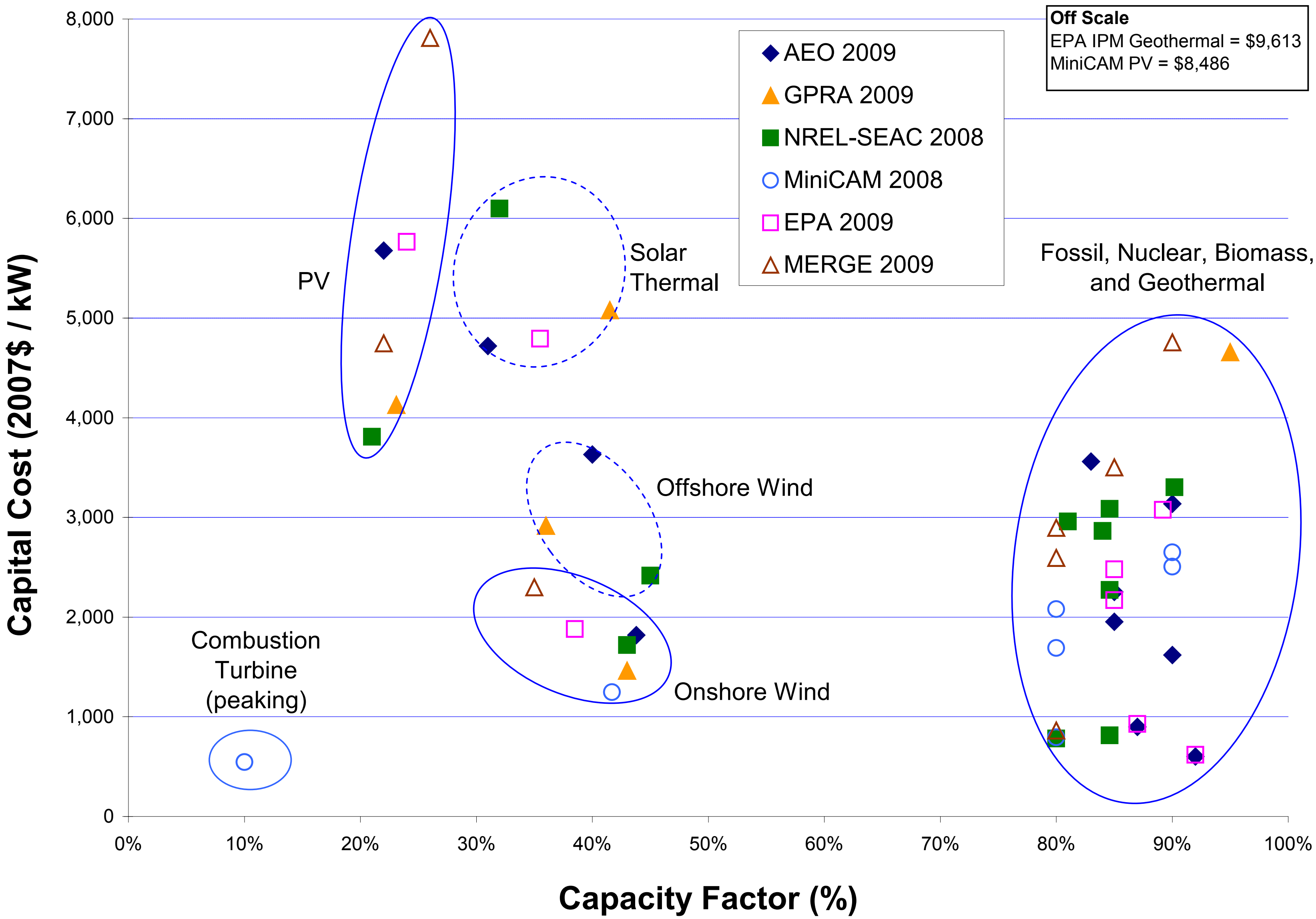


Figure 22. Overnight capital costs versus capacity factors, 2010

Figure 23 considers the capital costs and capacity factors for 2025. Compared to 2010, the data points on the chart have generally moved down (i.e., lower capital costs) and to the right (i.e., higher capacity factors), corresponding to lower capital costs and high capacity factors. With the exception of the MiniCAM combustion turbine data point (peaking plant), the nuclear, biomass, and fossil fuel plants are again at the right edge (high capacity factor). Onshore wind and PV have moved slightly to the right, while offshore wind and especially solar thermal have moved noticeably to the right (higher capacity factors).

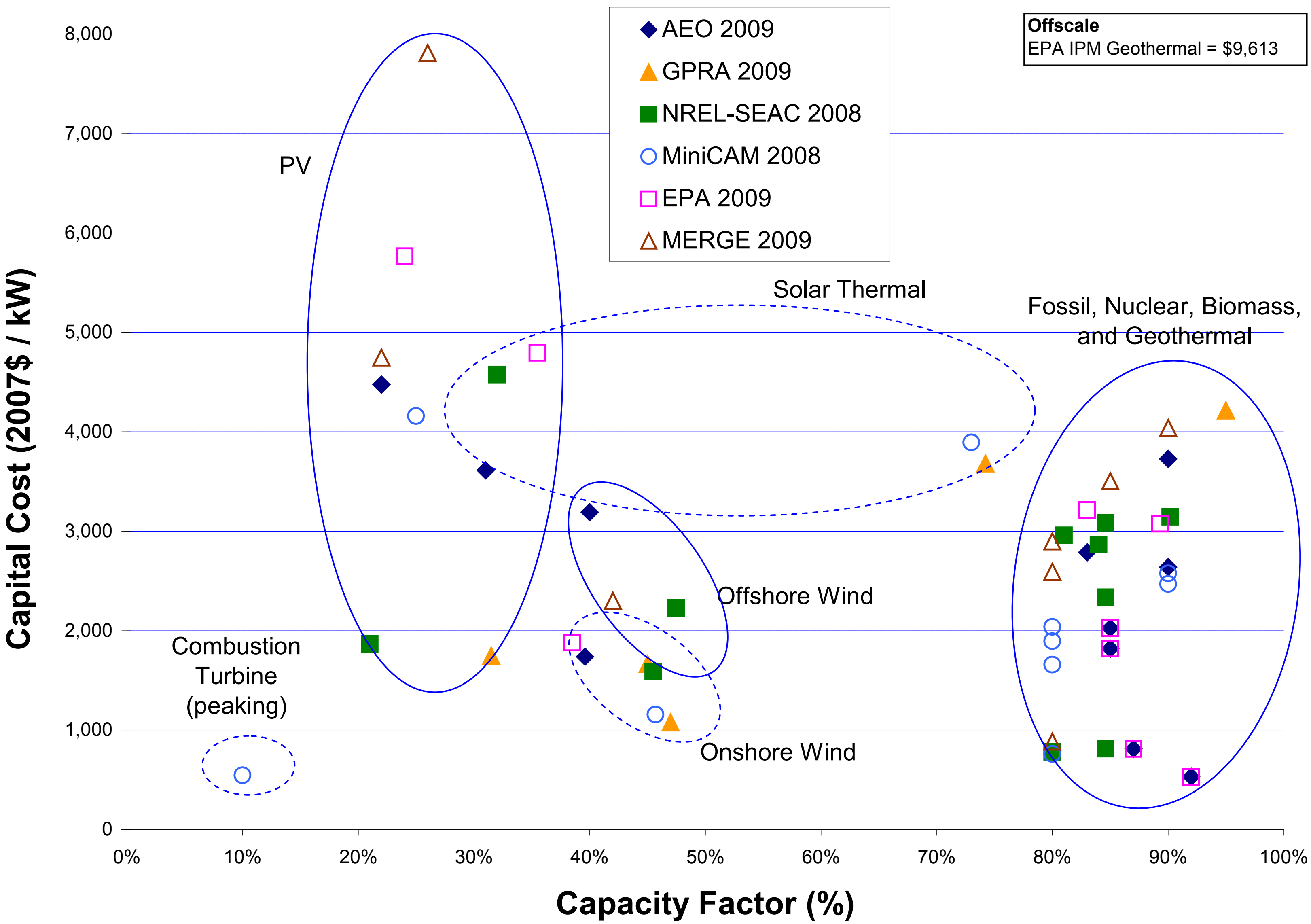


Figure 23. Overnight capital costs versus capacity factors, 2025

3.2 Learning

For the data sets evaluated in this study, learning is in some cases treated as in input parameter in the data set, and in other cases, learning is handled as an output parameter generated from the model associated with the data set. This report is focused on data sets, not energy models, and a detailed examination of learning in individual models is beyond the project scope. However, a few observations concerning learning include the following:[23]

- In the AEO 2009 data set, learning is handled as an endogenous variable (i.e., model output), which is generated by the NEMS model. The overnight capital costs that are presented in this report do include learning effects generated from the NEMS modeling analysis that was conducted using the AEO 2009 data set characteristics.
- For the NREL-SEAC 2008 data set, the impact of R&D (referred to as "learning by R&D") is included in the data set, but the impact of "learning by doing" is not. Instead, the ReEDS model calculates "learning by doing" based upon the installed capacity additions for each technology.
- The GPRA data set is developed by multiple technology programs in the Department of Energy, which may address learning using different methodologies. However, the data set is believed to handle learning in a similar fashion as the NREL-SEAC data set. That is, "learning by R&D" is included in the data set, but "learning by doing" is not. For the most part, GPRA uses accelerated assumptions for R&D investment relative to NREL-SEAC, and hence larger reductions generally occur in overnight capital costs over time.
- The EPA data set is constructed in a similar fashion as the AEO data set. That is, learning is a model output.
- How learning effects are handled in the MERGE and MiniCAM data sets, and the associated models, is not well understood due to a lack of publicly available documentation. The overnight capital costs in MERGE show little or no change over time, suggesting that learning is handled in the MERGE model, not the MERGE data set. For MiniCAM, overnight capital costs do decline over time, suggesting the MiniCAM data set includes endogenous learning.
- Certain models may incorporate growth rate penalties wherein the capital cost of a technology may increase due to rapid increases in demand (i.e. demand exceeds supply). This dynamic is not addressed in detail in this study, but growth penalties have the potential to reduce the levels of learning reported here and are worth further inquiry.
- The influence of learning can be observed in Figure 24 through Figure 34, which show normalized overnight capital costs for all six data sets (normalized such that the cost in the first year is one). In Table 14, the annual change in overnight costs is shown for a 15-year period – 2015 through 2030.

[23] Additional comments on learning effects are briefly discussed for each data set in the appendices (see learning sections in Appendix A through Appendix F).

Table 14. Annual Change in Overnight Capital Costs, 2015 to 2030

	Data Set					
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**
Coal	1.9%	N/A	no change	0.3%	1.2%	no change
IGCC	2.2%	N/A	no change	X	1.3%	no change
Combustion Turbine	2.4%	N/A	no change	0.2%	1.5%	N/A
Combined Cycle	2.2%	N/A	no change	0.6%	1.3%	-0.2%
Nuclear	2.6%	N/A	0.5%	0.1%	no change	1.1%
Biomass	2.7%	N/A	no change	0.3%	0.9%	no change
Geothermal	2.3%	0.6%	no change	0.4%	no change	N/A
Wind (onshore)	1.6%	1.1%	0.5%	0.5%	no change	no change
Wind (offshore)	2.2%	2.4%	0.4%	N/A	N/A	N/A
Solar Thermal	3.2%	2.2%	no change	X	no change	no change
PV	3.1%	2.1%	3.4%	3.8%	no change	no change

N/A Technology not included in data set
X Technology included in data set, but online year occurs after 2015

As Table 14 shows, costs in the AEO data set decline at an annual rate between 1.6% (onshore wind) and 3.2% (solar thermal). For technologies in the GPRA data set, the annual cost declines range from 0.6% to 2.4%. In the NREL-SEAC data set, all but one of the technologies show no change in costs or a modest change (<1%). PV is the only technology in the NREL-SEAC data set with an annual cost reduction greater than 1% per year for the period between 2015 and 2030. In MiniCAM, the only technology with a change greater than 1% is PV. For the EPA data set, all fossil technologies decline at a rate greater than 1%, while the renewable and nuclear technologies show a change less than 1% (most exhibit no change). In MERGE, most technologies show no change in overnight capital costs, although combined cycle actually shows a small increase (only entry in Table 14 that shows a cost increase between 2015 and 2030).

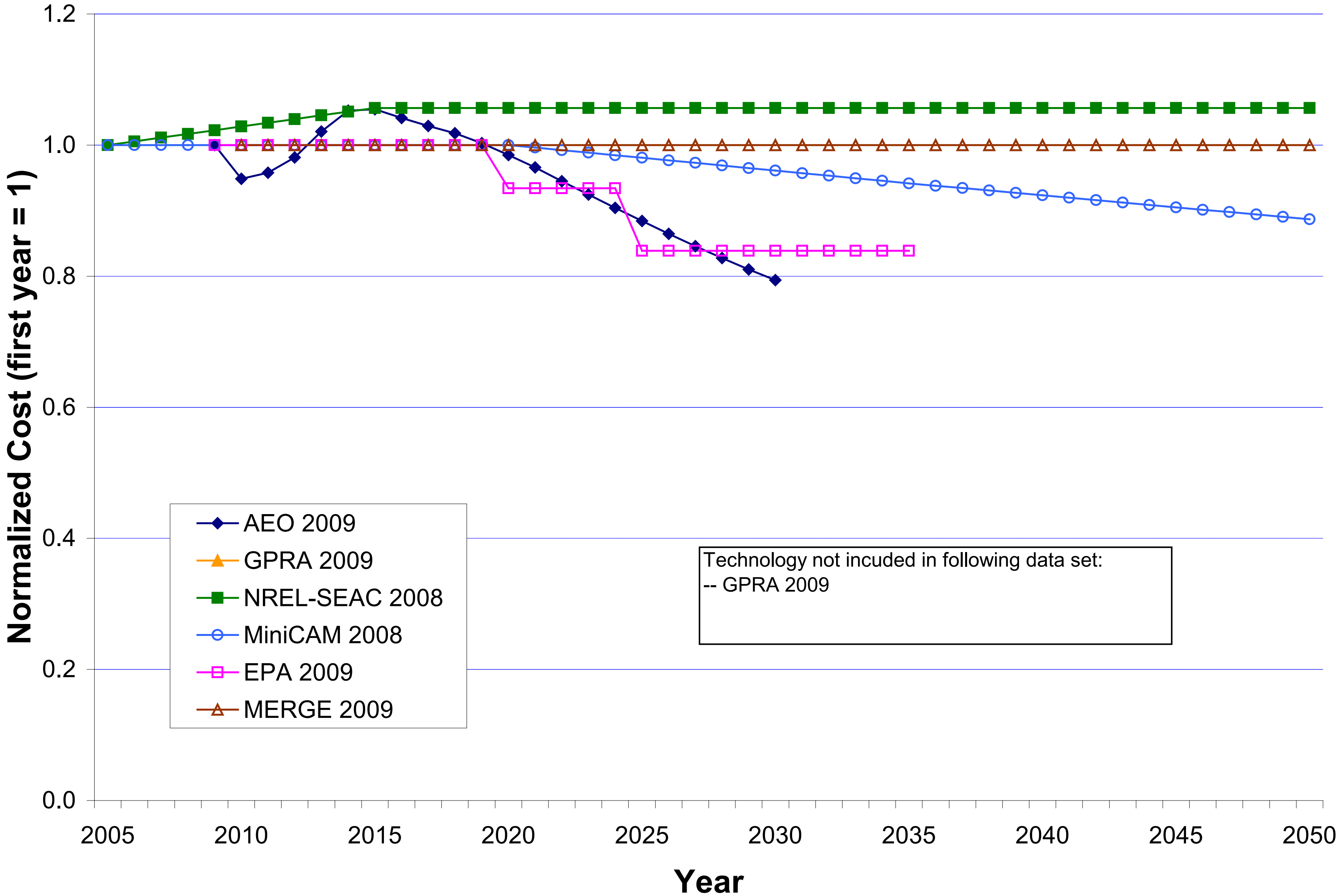


Figure 24. Normalized capital costs—coal

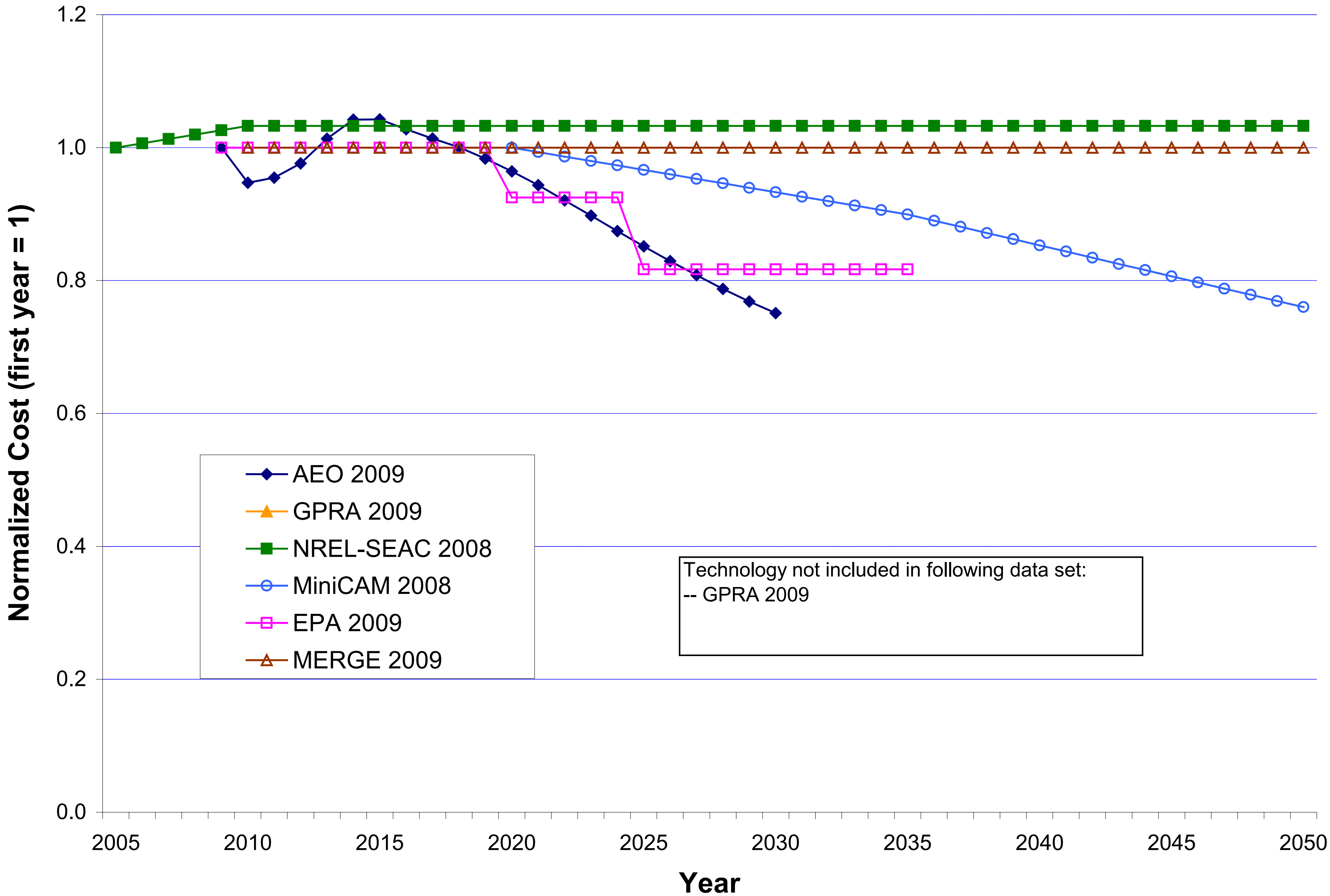


Figure 25. Normalized capital costs—IGCC

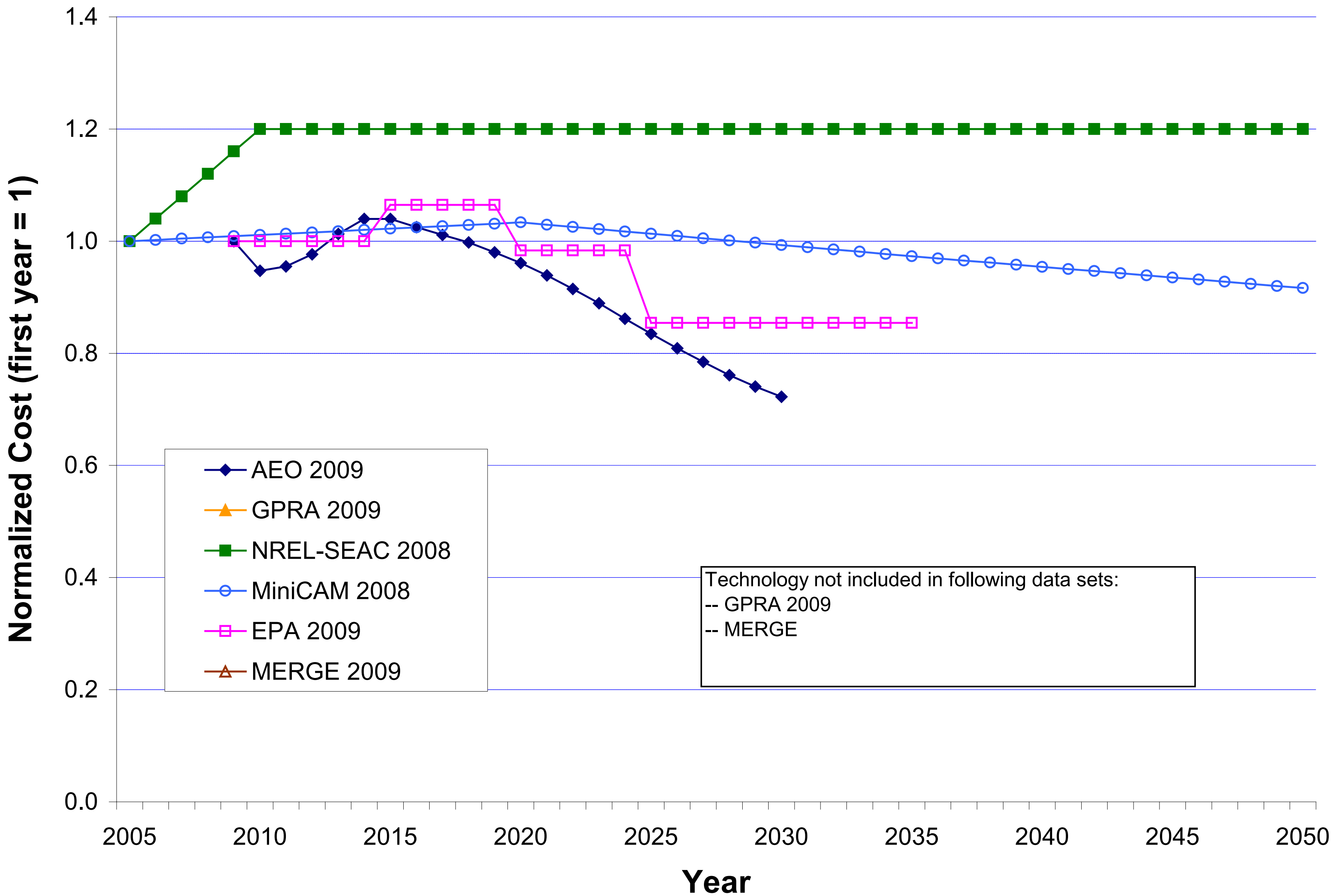


Figure 26. Normalized capital costs—combustion turbine

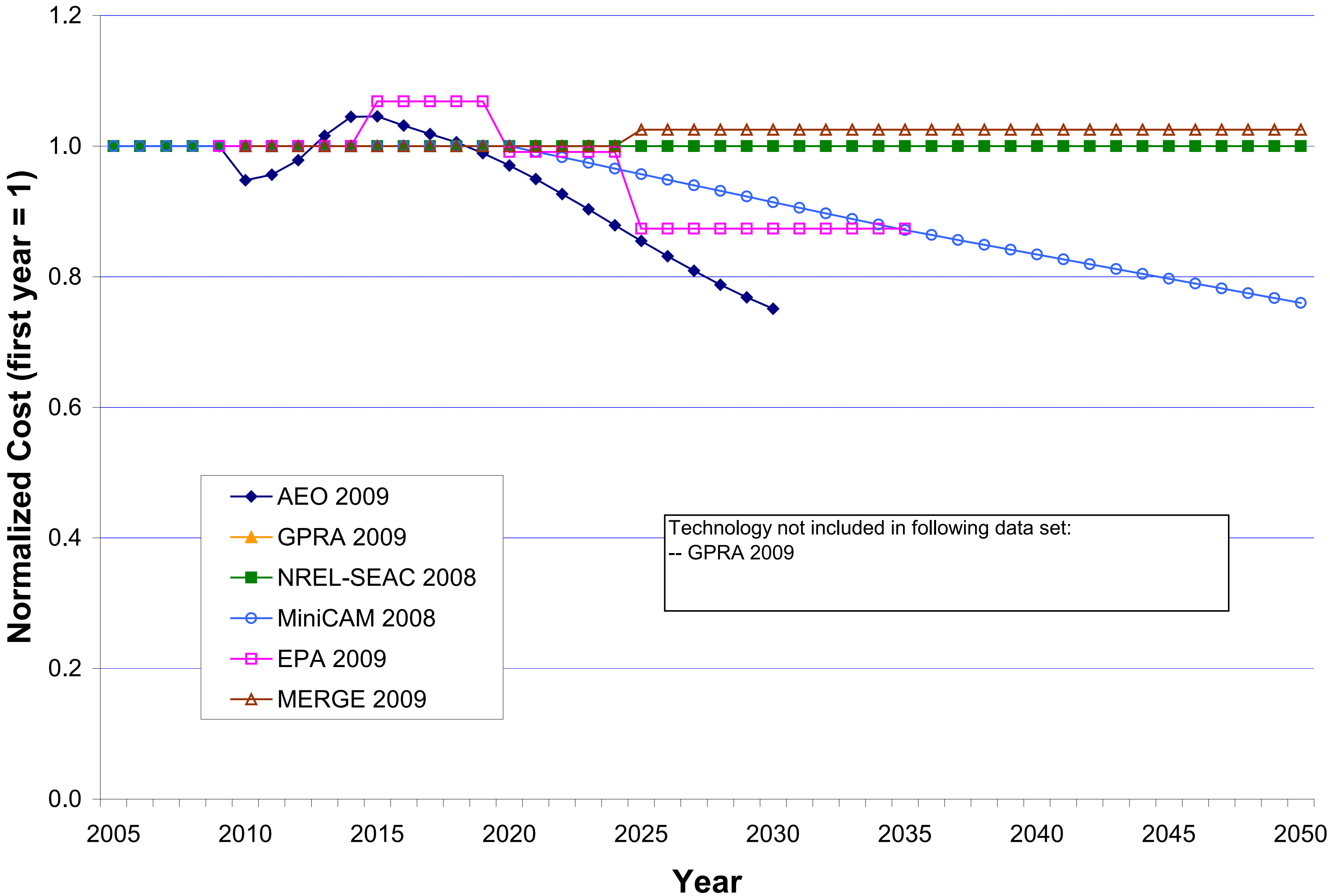


Figure 27. Normalized capital costs—combined cycle

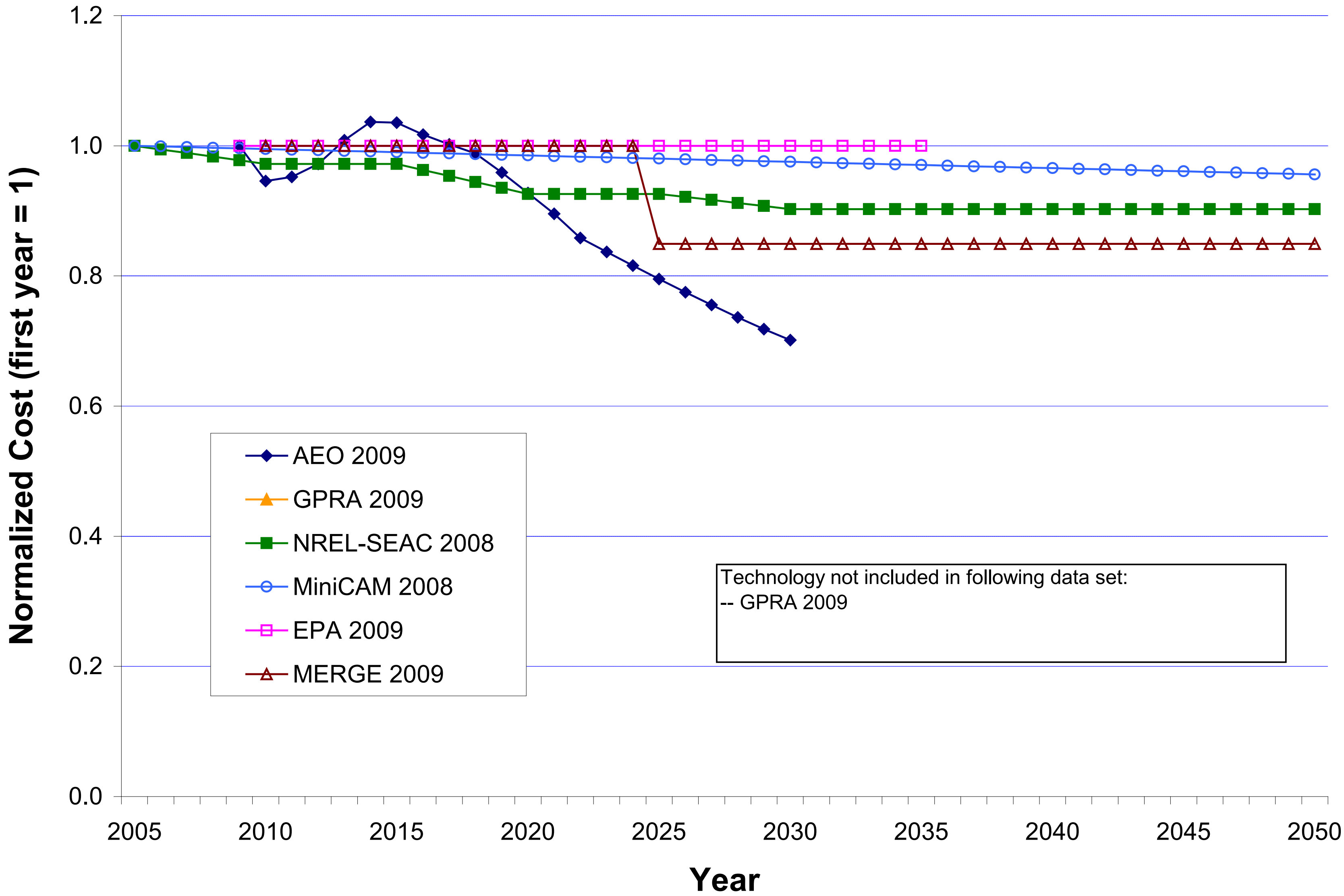


Figure 28. Normalized capital costs—nuclear

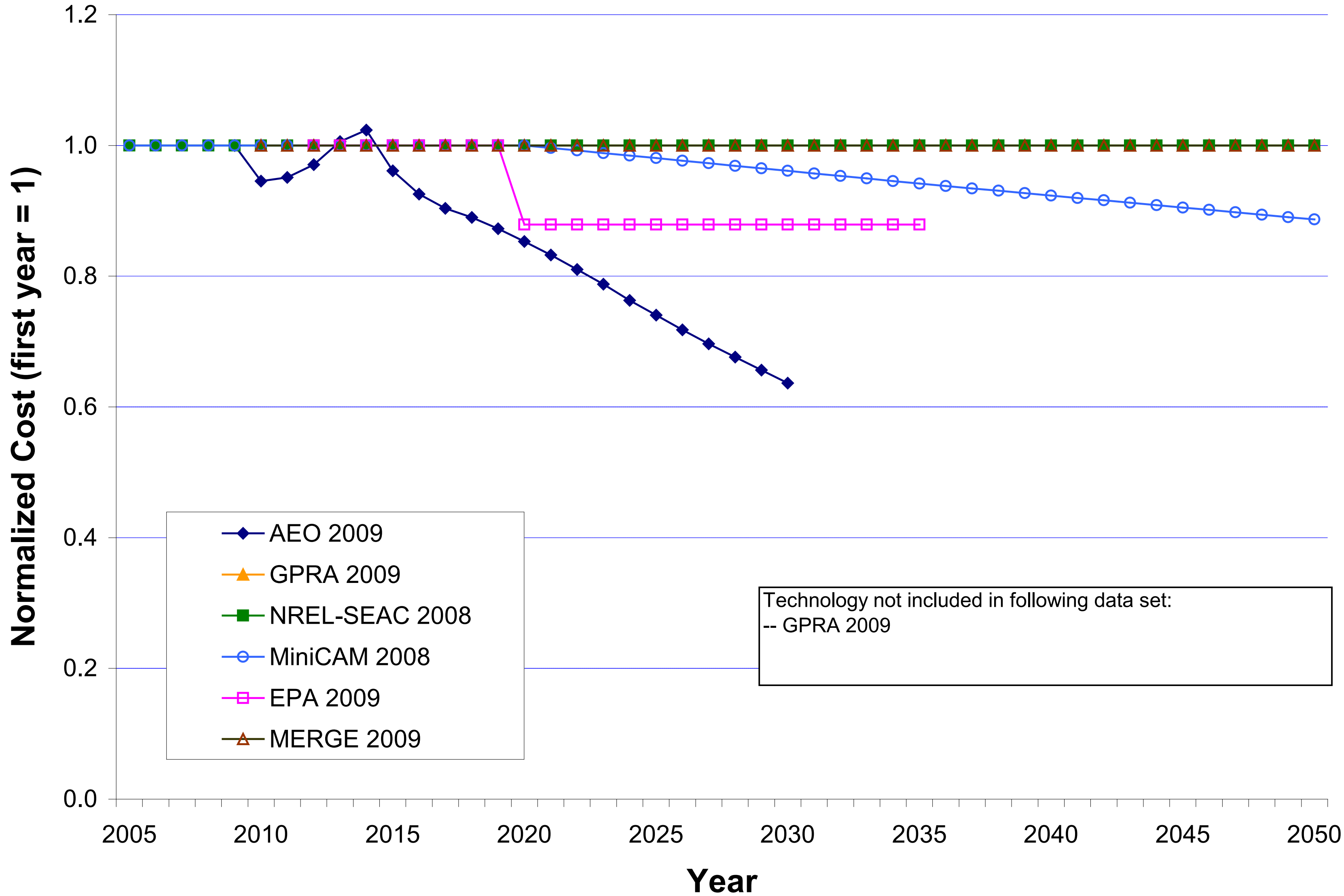


Figure 29. Normalized capital costs—biomass

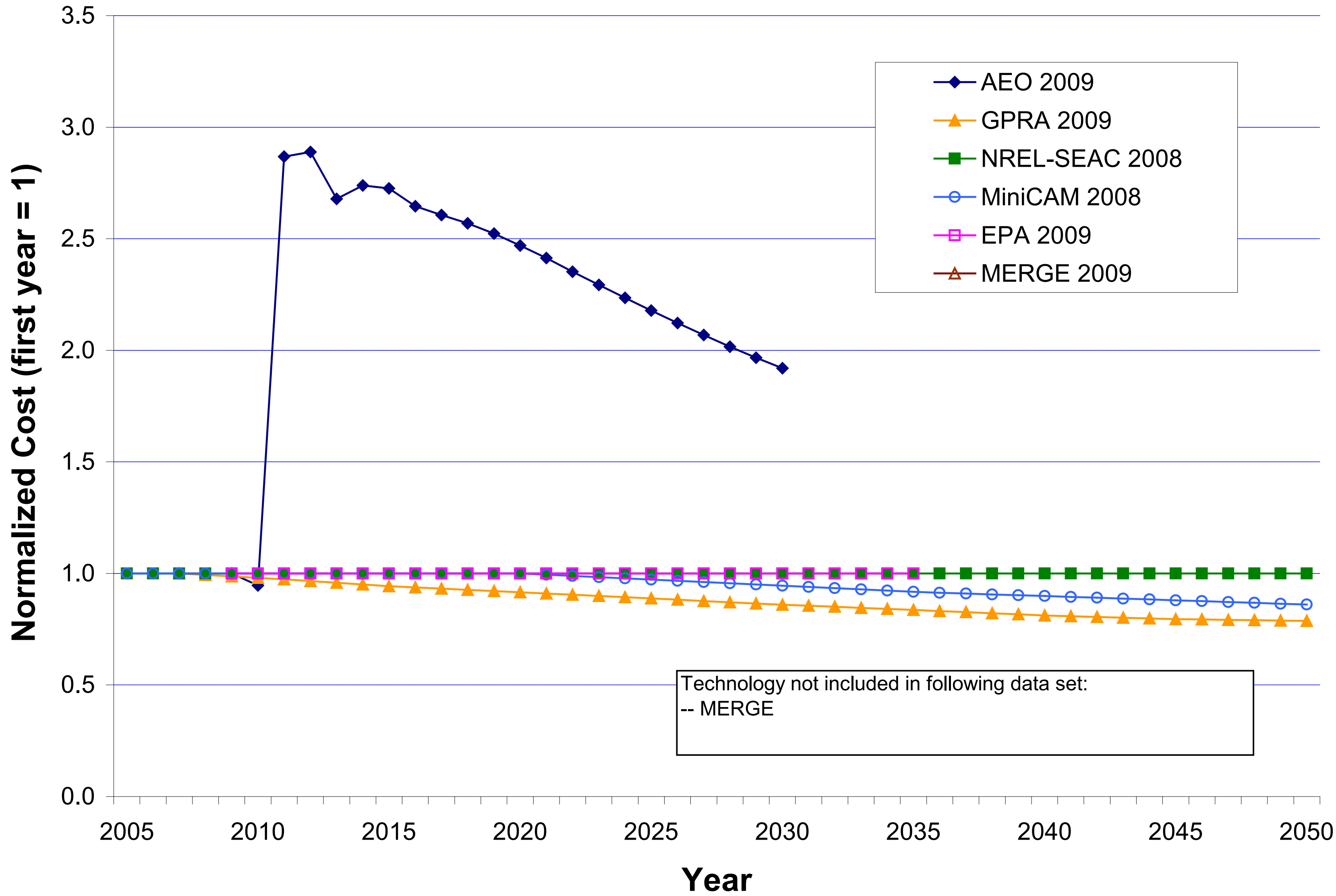


Figure 30. Normalized capital costs—geothermal

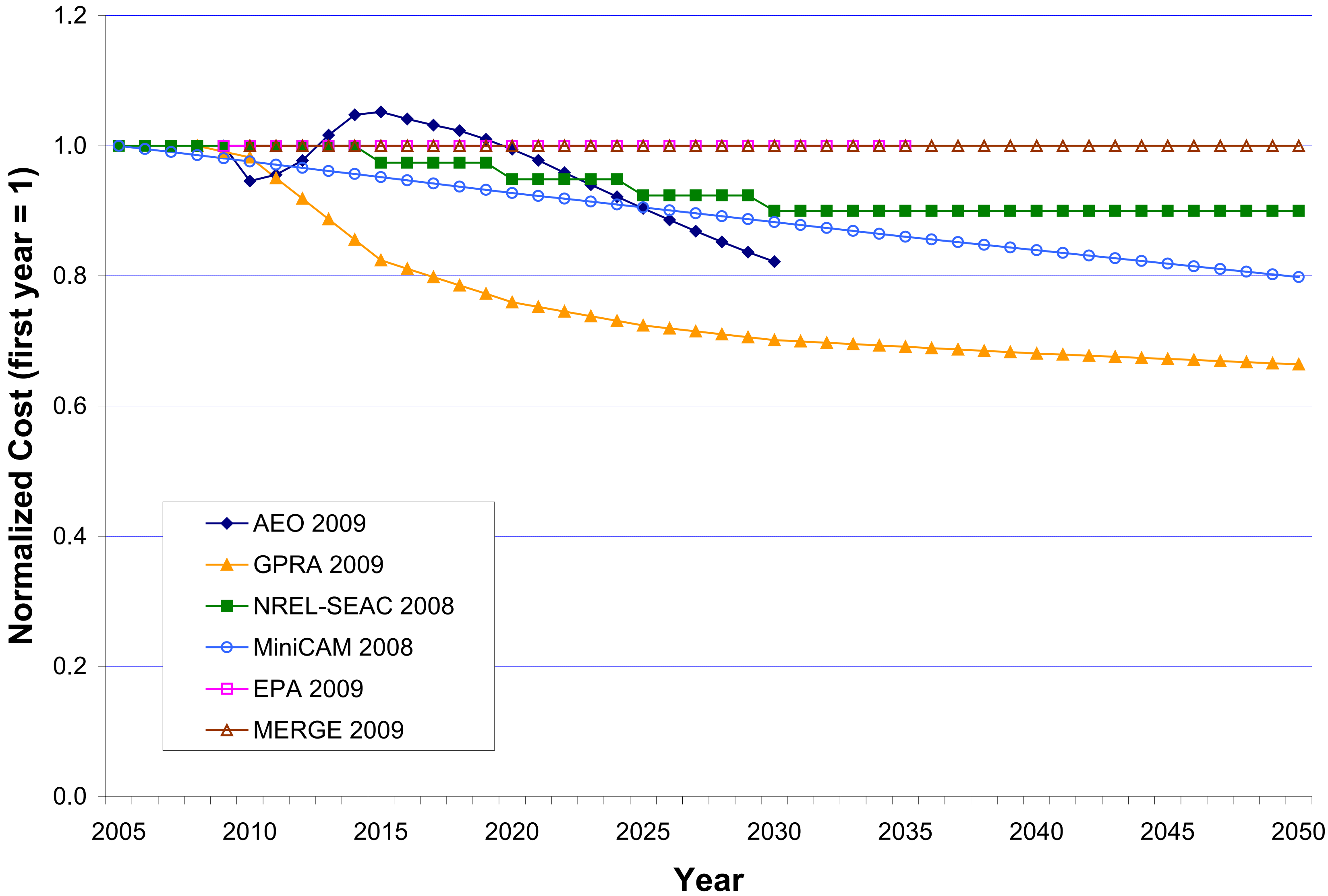


Figure 31. Normalized capital costs—wind (onshore)

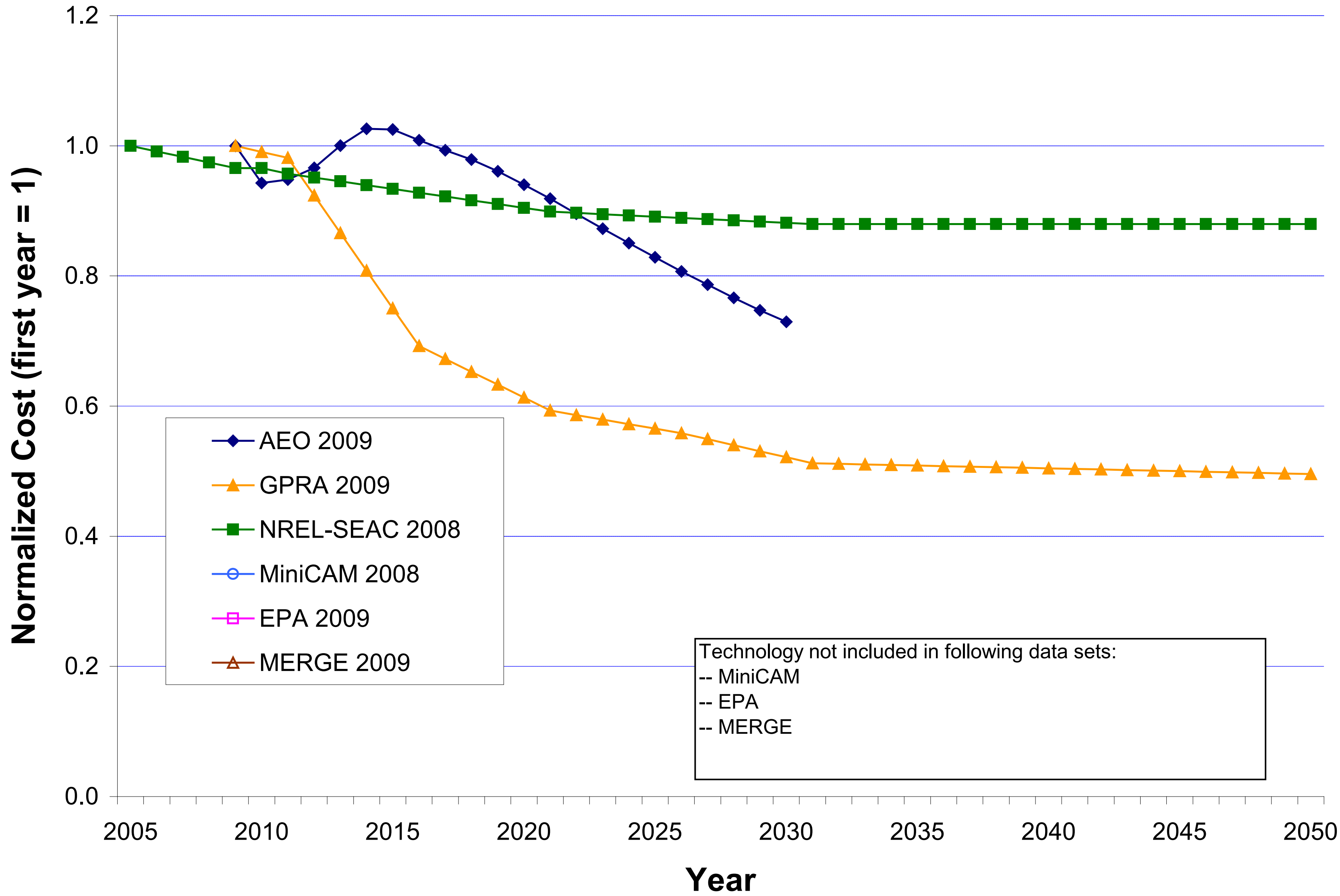


Figure 32. Normalized capital costs—wind (offshore)

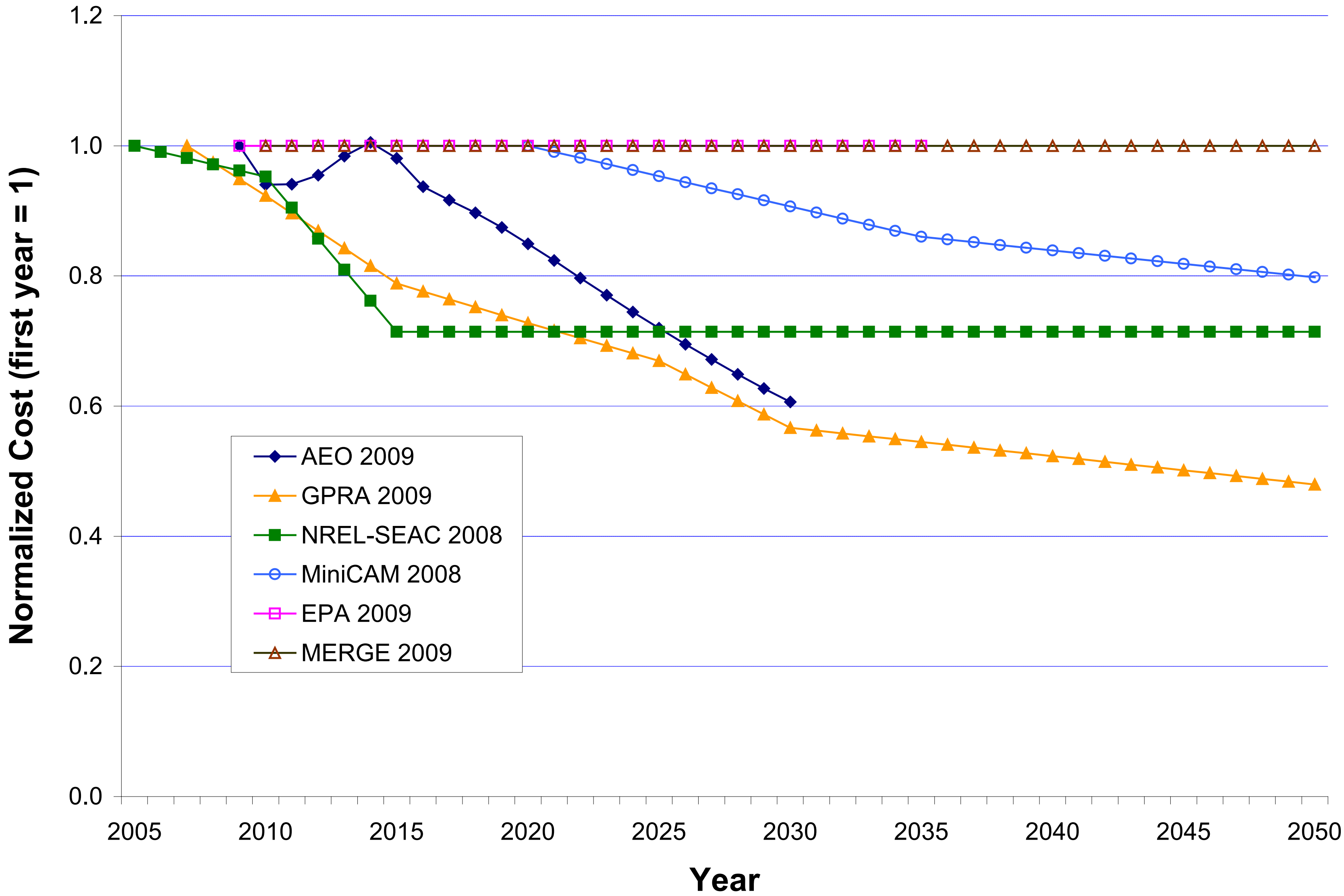


Figure 33. Normalized capital costs—solar thermal

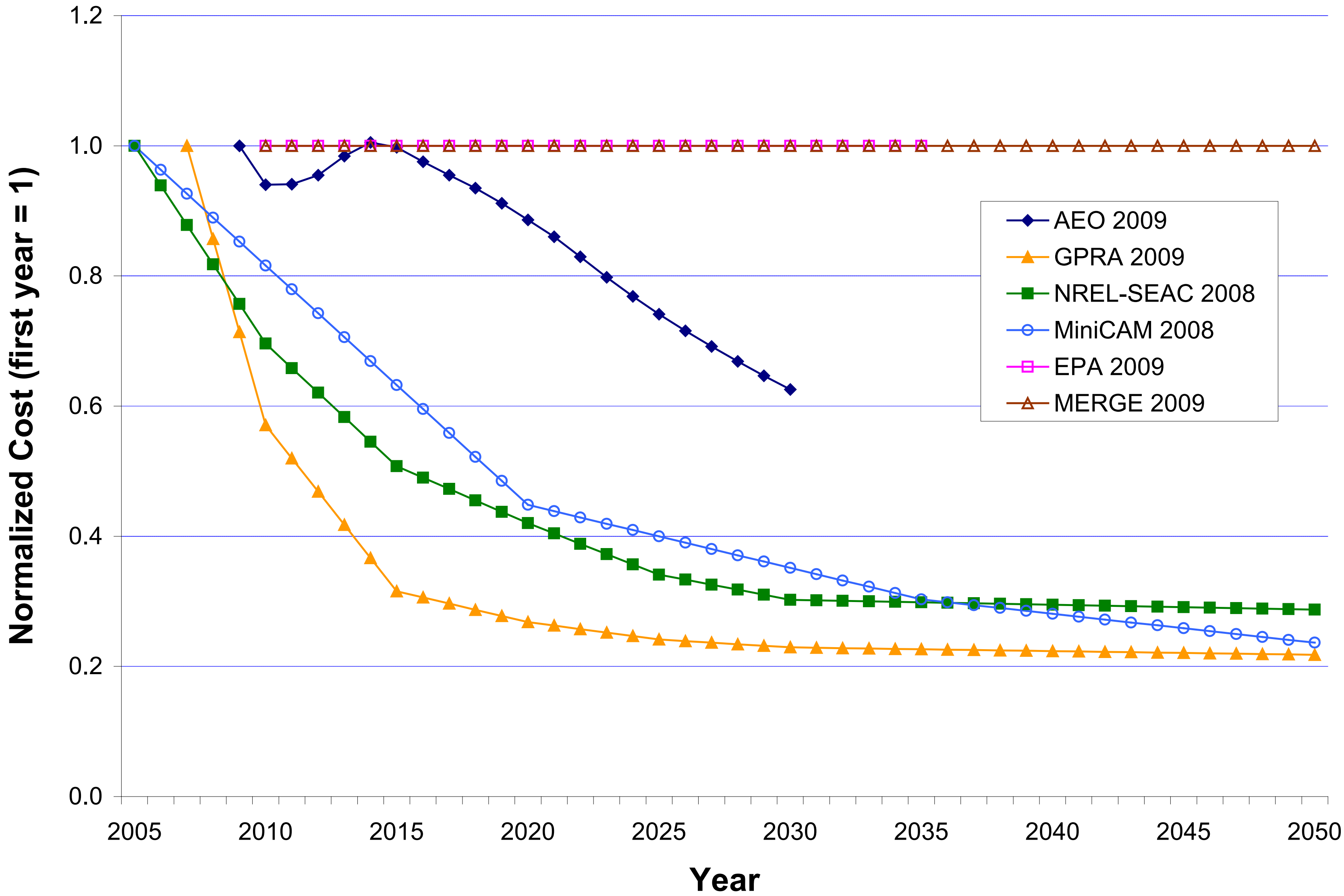


Figure 34. Normalized capital costs—PV

3.3 O&M Costs

Fixed O&M costs in 2015 are shown in Table 15 and Figure 35. The GPRA data set does not include fossil and biomass technologies, and the MiniCAM and EPA data sets do not include offshore wind (hence, O&M costs are not presented for these entries). The MiniCAM data set does include IGCC and solar thermal technologies, but the online year for these technologies occurs later than 2015. As Table 15 shows, no O&M costs are reported for the MERGE data set. All-inclusive O&M costs were calculated for the MERGE data set, but a breakdown of fixed and variable O&M costs was not available for comparison with other data sets.

Table 15. Fixed O&M in 2015 (2007$/kW/yr)

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	27.53	---	36.78	30.10	27.52	---	4.37	14%
IGCC	38.67	---	39.70	---	38.72	---	0.58	1%
Combustion Turbine	10.53	---	6.88	12.65	10.58	---	2.40	24%
Combined Cycle	11.70	---	15.00	13.22	11.71	---	1.57	12%
Nuclear	90.02	---	93.77	70.06	90.02	---	10.75	13%
Biomass	64.45	---	72.93	36.77	64.49	---	15.77	26%
Geothermal (hydrothermal)	164.64	119.89	174.49	86.19	184.34	---	41.50	28%
Wind (onshore)	30.30	24.73	11.98	12.59	30.29	---	9.14	42%
Wind (offshore)	89.48	130.42	15.63	---	---	---	58.18	74%
Solar Thermal	56.78	49.83	48.79	---	56.79	---	4.34	8%
PV (utility scale)	11.68	5.32	9.92	58.38	11.71	---	21.94	113%

Coefficient of variation (CV) is the standard deviation divided by the mean.

The coefficient of variation is greater than or equal to 20% for six technologies – combustion turbines, biomass, geothermal, onshore wind, offshore wind, and PV. The largest coefficient of variation occurs for PV, where the MiniCAM data set has a fixed O&M cost that is significantly higher than those of any of the other data sets are.

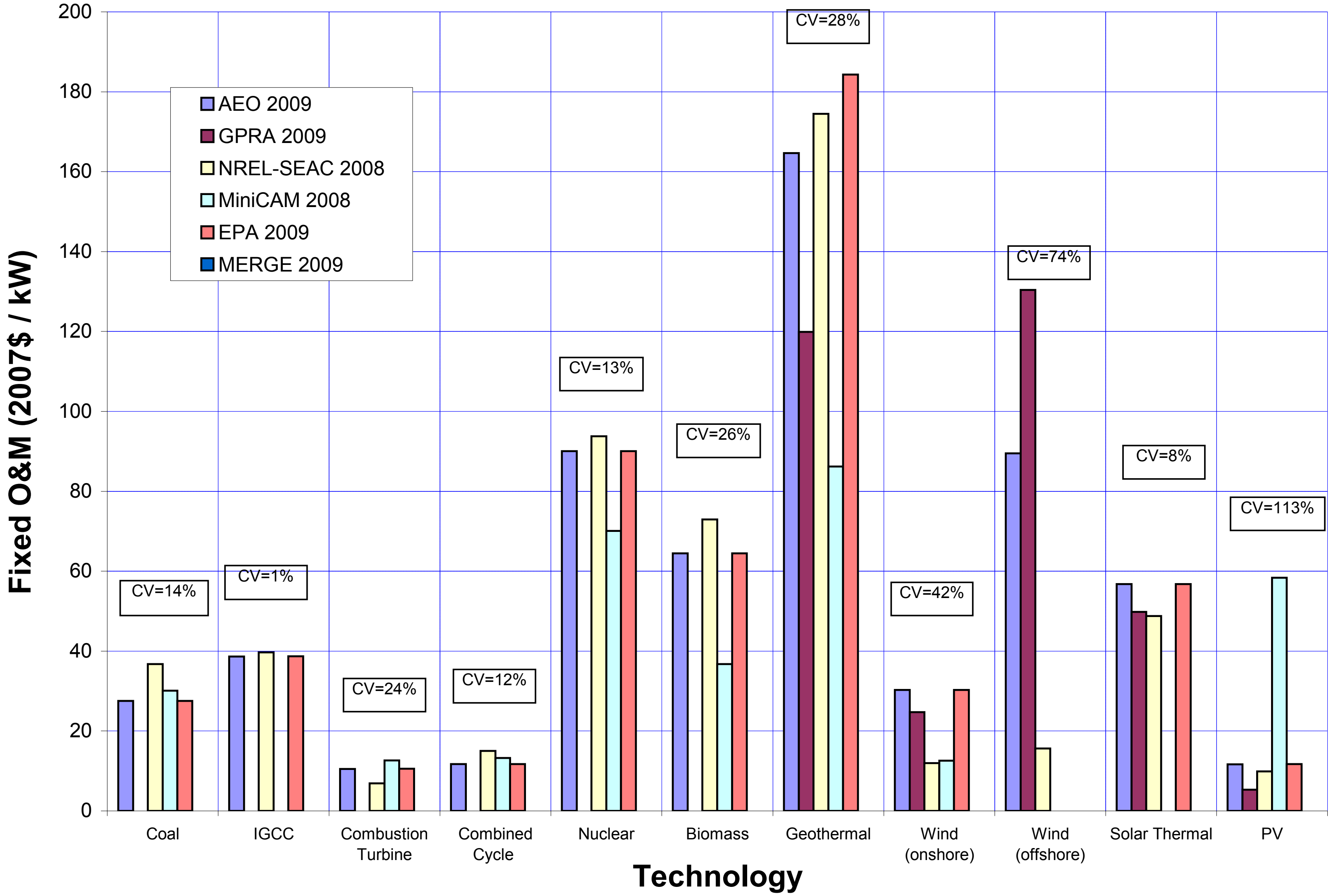


Figure 35. Fixed O&M costs, 2015

Variable O&M costs are shown in Table 16 and Figure 36. A few observations concerning variable O&M costs include:

- For geothermal and PV, variable O&M costs are zero in all data sets, and the resulting coefficient of variation is 0%.
- The coefficient of variation for nuclear plants is 85%. The reason for this high CV is that most data sets report a variable O&M cost for near $0.50/MWh, while the MiniCAM data set has a significantly higher cost near $2/MWh.
- The coefficient of variation exceeds 100% for onshore wind, offshore wind, and solar thermal technologies. The reason for these large CVs occurs primarily because some data have zero variable O&M costs, while other data sets report a variable O&M cost component. In some cases, the absolute costs are small, but the coefficient of variation turns out to be large. For example, with solar thermal, three data sets report zero costs, and one data set (NREL-SEAC) reports a small cost ($0.11/MWh). Based on these costs, the coefficient of variation for solar thermal technologies turns out to be 200%.

Table 16. Variable O&M in 2015 (2007$/MWh)

	Data Set							
Technology	**AEO**	**GPRA**	**NREL-SEAC**	**MiniCAM**	**EPA**	**MERGE**	**Standard Deviation**	**Coefficient of Variation**
Coal	4.59	---	1.77	5.02	4.59	---	1.50	37%
IGCC	2.92	---	4.06	---	2.92	---	0.66	20%
Combustion Turbine	3.17	---	2.92	3.77	3.17	---	0.36	11%
Combined Cycle	2.00	---	3.13	2.22	2.00	---	0.54	23%
Nuclear	0.49	---	0.52	1.97	0.49	---	0.74	85%
Biomass	6.71	---	10.42	5.09	6.68	---	2.26	31%
Geothermal (hydrothermal)	0.00	0.00	0.00	0.00	0.00	---	0.00	0%
Wind (onshore)	0.00	0.00	5.21	5.91	0.00	---	3.06	137%
Wind (offshore)	0.00	0.00	16.67	---	---	---	9.62	173%
Solar Thermal	0.00	0.00	0.11	---	0.00	---	0.06	200%
PV	0.00	0.00	0.00	0.00	0.00	---	0.00	0%

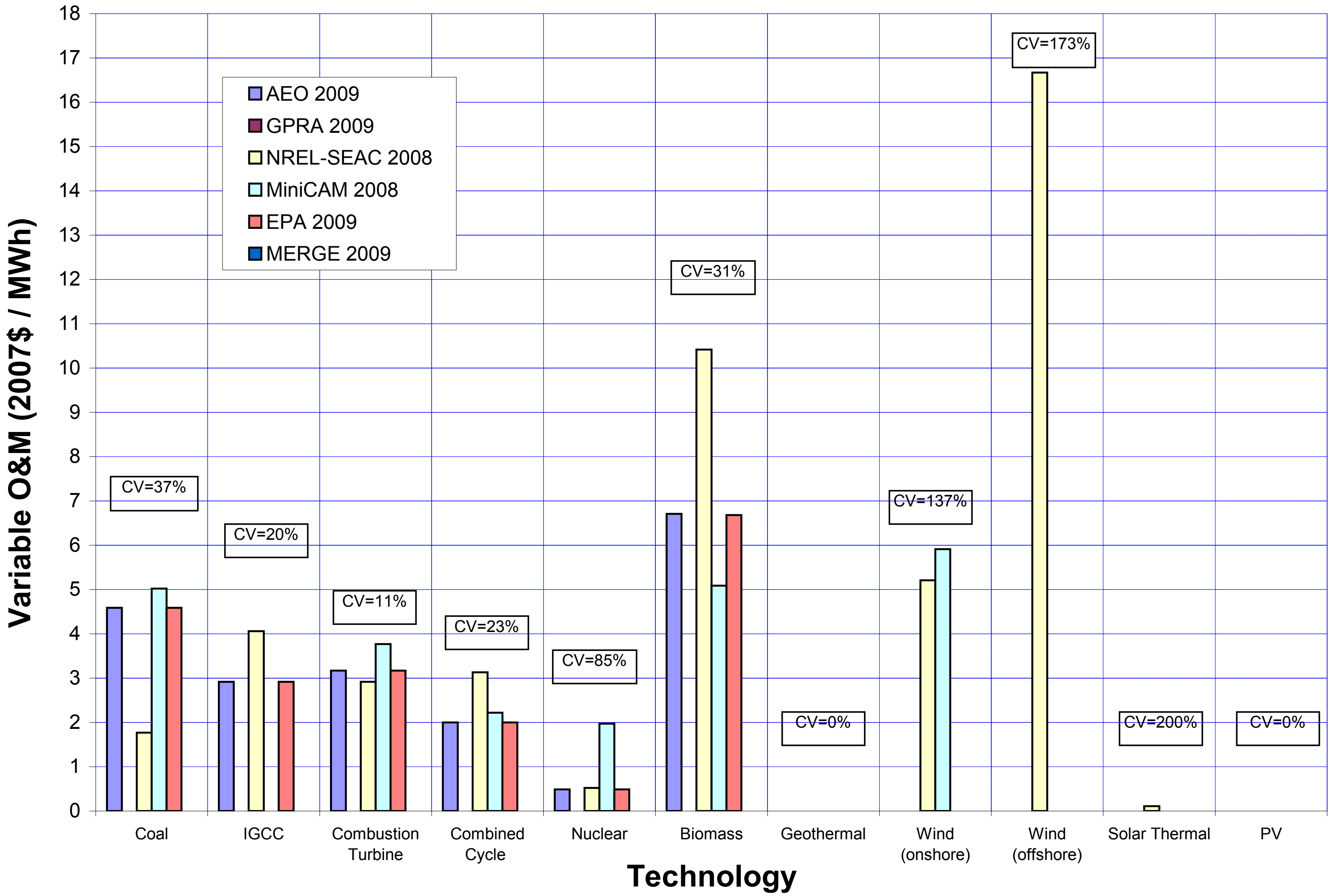


Figure 36. Variable O&M costs, 2015

4 Levelized Cost of Energy (LCOE)

A levelized cost of energy (LCOE) tool was developed, and this tool was used to calculate LCOE values for electricity generation technologies. Additional details on the LCOE tool are included in Appendix G.

The LCOE tool was designed for rapid comparison of technology cost and performance characteristics, not for project or location specific analyses. It is important to recognize that the LCOE tool does not represent the decision-making structure of the models discussed in this report. Models have complex decision-making processes and other energy system properties to determine electricity portfolios that are not incorporated in the LCOE tool. The LCOE tool utilizes very basic financial assumptions, as the intent is to compare technology cost and performance characteristics, not to analyze the impacts of detailed financial assumptions. Thus, no taxes, tax incentives, or debt/equity financing structures are considered.

The exclusion of taxes from the analysis may have a favorable effect on certain technologies with high capital costs and low operational costs (e.g. renewable technologies). Similarly, the exclusion of tax credits and depreciation incentives may have a relatively favorable effect on conventional technologies compared with renewables. Future studies would benefit from performing sensitivity analyses of LCOE with changes in financial assumptions.

LCOE values were computed for 11 technologies (see Table 3) in six data sets (see Table 1). LCOE values were first computed for a set of baseline conditions as described in Table 17. In addition to the baseline conditions, several alternative scenarios were analyzed as noted in Table 17.

Table 17. LCOE Calculations

Parameter	Baseline Conditions	Alternative Scenarios or Calculations
Year	2015[24]	All years from 2005 through 2050
Currency Basis	2007 real dollars	Same for all scenarios
Equipment Cost	Default Values in LCOE Tool	+10%, +20%, +50%
Labor Cost	Default Values in LCOE Tool	+10%, +20%, +50%
Fuel Cost	From AEO 2009 data set	+10%, +20%, +50%
Discount Rate (real)	7.0%	No change
Lifetime	From NREL-SEAC 2008 data set[25]	No change

LCOE values were calculated for 2005 through the last year in each data set[26]. For each year, a total of 10 different scenarios were computed as indicated in Table 18. The 10 scenarios were

[24] The year 2015 was selected for the baseline year to allow coverage across all data sets. The EPA 2009 data set does not contain records for 2010. The first on-line year for technologies in the EPA 2009 data set is 2012.
[25] To eliminate the effect of plant lifetimes on LCOE calculations, the same set of lifetimes were used for calculations. NREL-SEAC had the most complete set of plant lifetimes, and the NREL-SEAC lifetimes were therefore selected for all LCOE calculations.
[26] The last year is 2050 for all data sets except AEO and EPA. The last year for AEO is 2030, and the last year for EPA is 2035.

selected to evaluate the parametric sensitivity of LCOE results to three input variables: 1) equipment costs, 2) labor costs, and 3) fuel costs

Table 18. LCOE Calculation Matrix

Scenario	Capital Cost Adjustment		Fuel Cost Adjustment
	Equipment (non-steel)	Labor	
1	0%	0%	0%
2		10%	
3		20%	
4		50%	
5	10%	0%	0%
6	20%		
7	50%		
8	0%	0%	10%
9			20%
10			50%

In this section, the LCOE results are discussed for the baseline scenario and the alternative scenarios. This section is organized as follows:

- Baseline results (2015 and 2030)
- Capital, O&M, and fuel costs (2015 and 2030)
- Time trends (2005 through 2050)
- Impact of equipment costs
- Impact of labor costs
- Impact of fuel costs

4.1 Baseline Results (2015 and 2030)

LCOE values for 2015, the baseline year, are shown in Figure 37, and for comparison LCOE values for 2030 are shown in Figure 38. All LCOE values are reported in 2007 dollars for the 11 technologies that span the six data sets (tabular data in Appendix I).

In 2015, the mean values for fossil technologies range from \$52/MWh (combined cycle) to \$77/MWh (combustion turbine) across the data sets. In 2030, the mean LCOE values for fossil technologies show small changes, generally upward. In 2030, the costs range from \$53/MWh (coal and combined cycle) to \$80/MWh (combustion turbine). Concerning the combustion turbine, the cost is relatively high in the MiniCAM data set. The reason for the high MiniCAM combustion turbine cost is that the combustion turbine in this data set is regarded as a peaking turbine and has a relatively low capacity factor (10%), which drives up the LCOE. Other data sets have a combustion turbine capacity factor of 80% or higher.

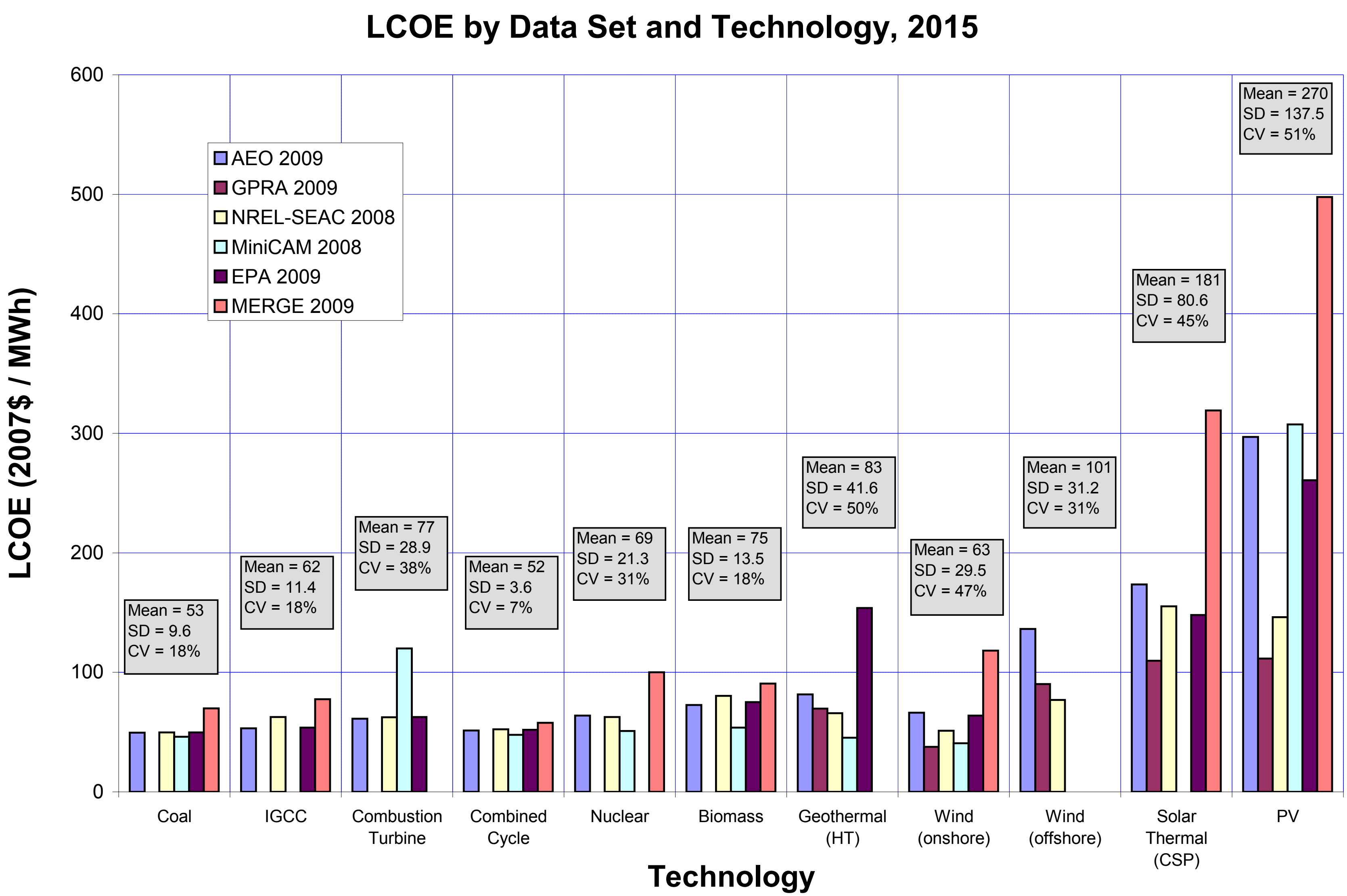


Figure 37. LCOE costs, 2015

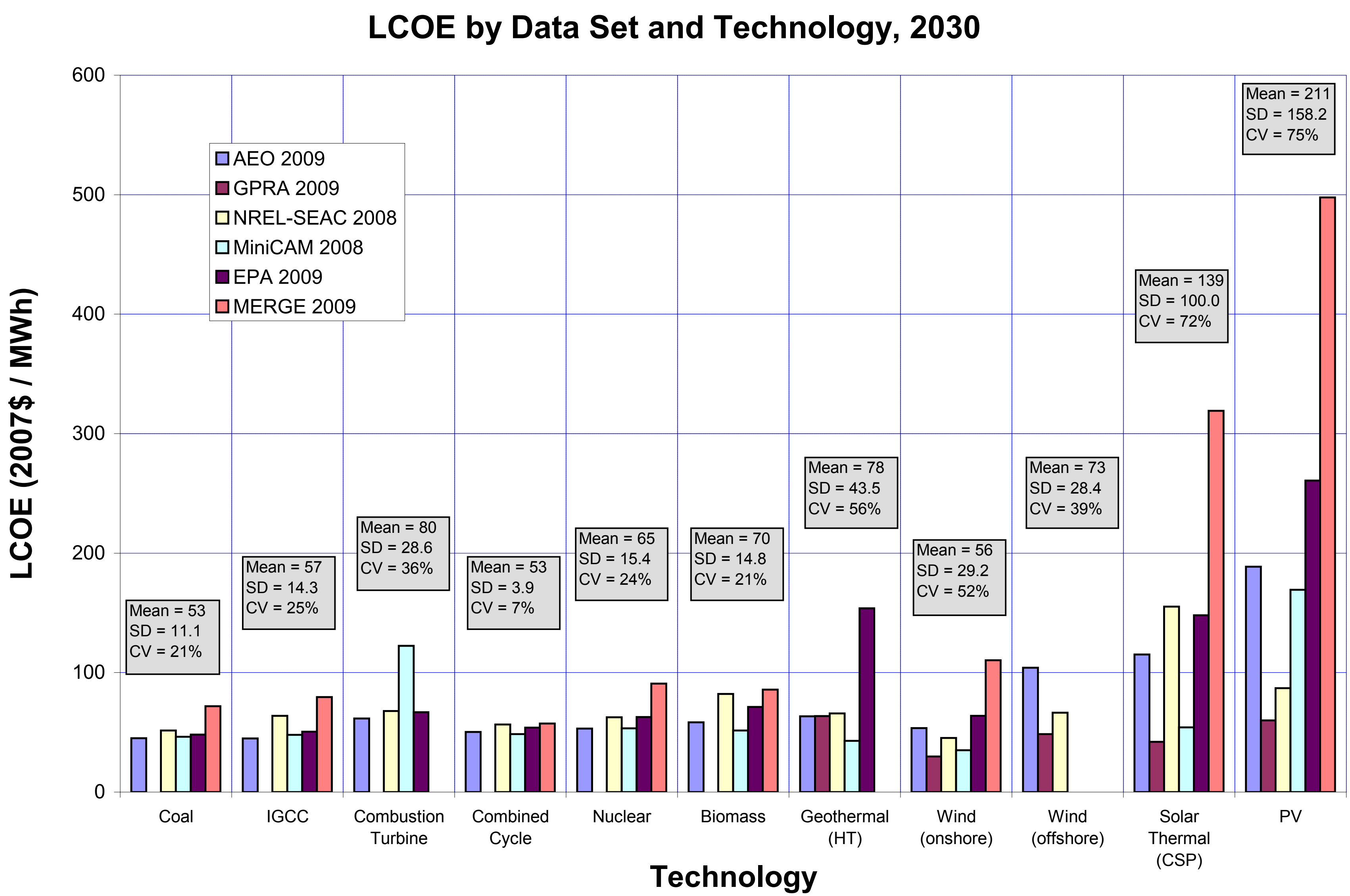


Figure 38. LCOE costs, 2030

As indicated in Figure 37 and Figure 38, nuclear costs show a slight decrease from a mean value of $69/MWh in 2015 to $65/MWh in 2030. Biomass and geothermal also show reductions – biomass declines from $75/MWh to $70/MWh, and geothermal declines from $83/MWh to $78/MWh. Concerning geothermal, the EPA data set is clearly at the high end. In this data set, a wide range of capital costs is provided depending on actual site conditions. In the EPA data set, geothermal costs were averaged, but the resulting capital cost was still quite high, which drives up the LCOE values for the EPA data set.

All six data sets included onshore wind, and in these data sets, onshore wind is generally one of the most competitive power generation technologies. In 2015, the LCOE for onshore wind is $63/MWh, falling to $56/MWh in 2030. The MERGE data set has relatively high capital costs for wind, which drives up the LCOE. Three of the data sets reported offshore wind characteristics, and based on these three data sets the LCOE for offshore wind falls from $101/MWh in 2015 to $73/MWh in 2030.

Solar thermal and PV are the most expensive power generation technologies. In 2015, the mean solar thermal cost is $181/MWh, and the mean PV cost is $270/MWh. In 2030, these costs fall to $139/MWh and $211/MWh, respectively. There is a large standard deviation for both solar thermal and PV, particularly in 2030. In 2030, the GPRA data set has a noticeably lower LCOE than the other data sets, while MERGE shows a significantly higher result.

Another perspective of LCOE costs is presented in Figure 39 and Figure 40. In these figures, LCOE costs are normalized to a coal plant for 2015 and 2030, respectively. Looking at the mean values, coal plants are the least expensive option in both 2015 and 2030 (tied with combined cycle in 2015). However, interesting observations are apparent when looking at individual data sets. For example, the cost of onshore wind in 2030 in the NREL-SEAC data set is lower than the cost of a coal plant (ratio < 1). The MiniCAM data set has a lower cost for onshore wind compared to a coal plant in both 2015 and 2030.

Another set of LCOE ratio plots is presented in Figure 41 and Figure 42, where onshore wind is used for normalization. Given the mean values in these two charts, it is easy to see how the competitive position of onshore wind changes between 2015 and 2030. In 2015, the mean cost of a coal plant is 85% (ratio = 0.85) of the mean cost for onshore wind, and in 2030 the cost differential declines to 94%. The gap between onshore wind and other renewables also shrinks. For example, relative to onshore wind, the mean cost of solar thermal declines from a ratio of 2.72 in 2015 to 2.29 in 2030.

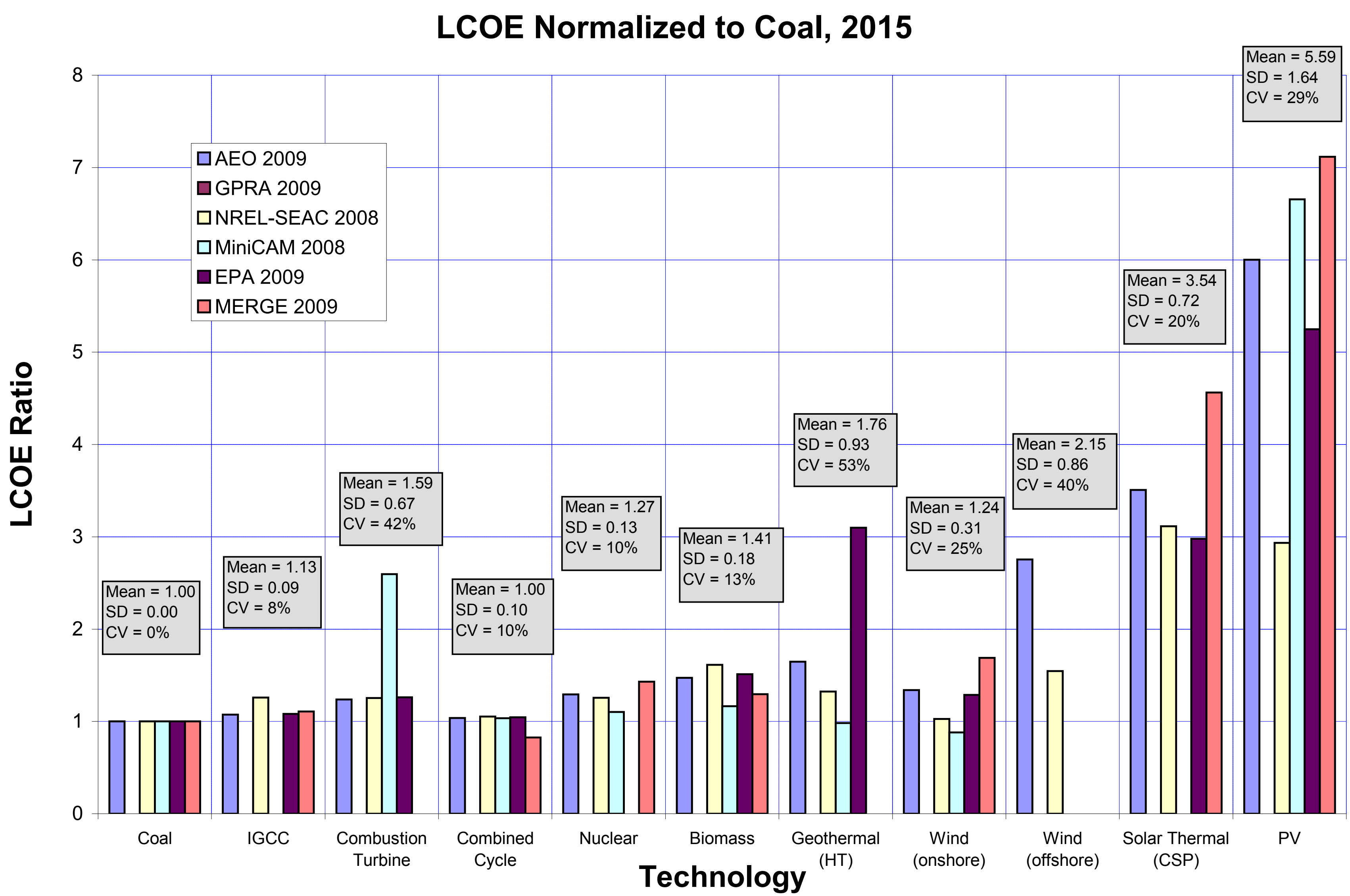


Figure 39. LCOE cost ratios relative to coal, 2015

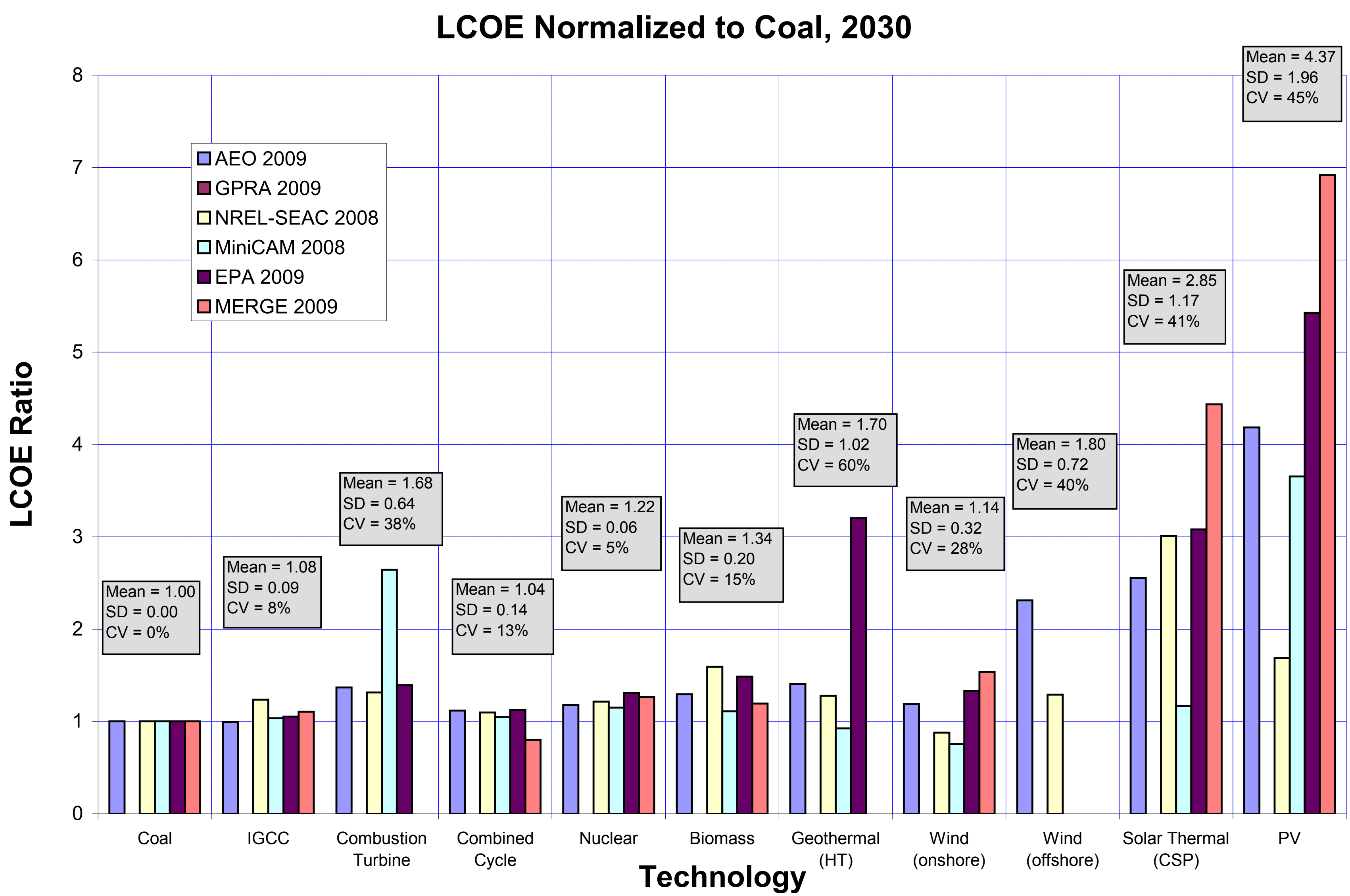


Figure 40. LCOE cost ratios relative to coal, 2030

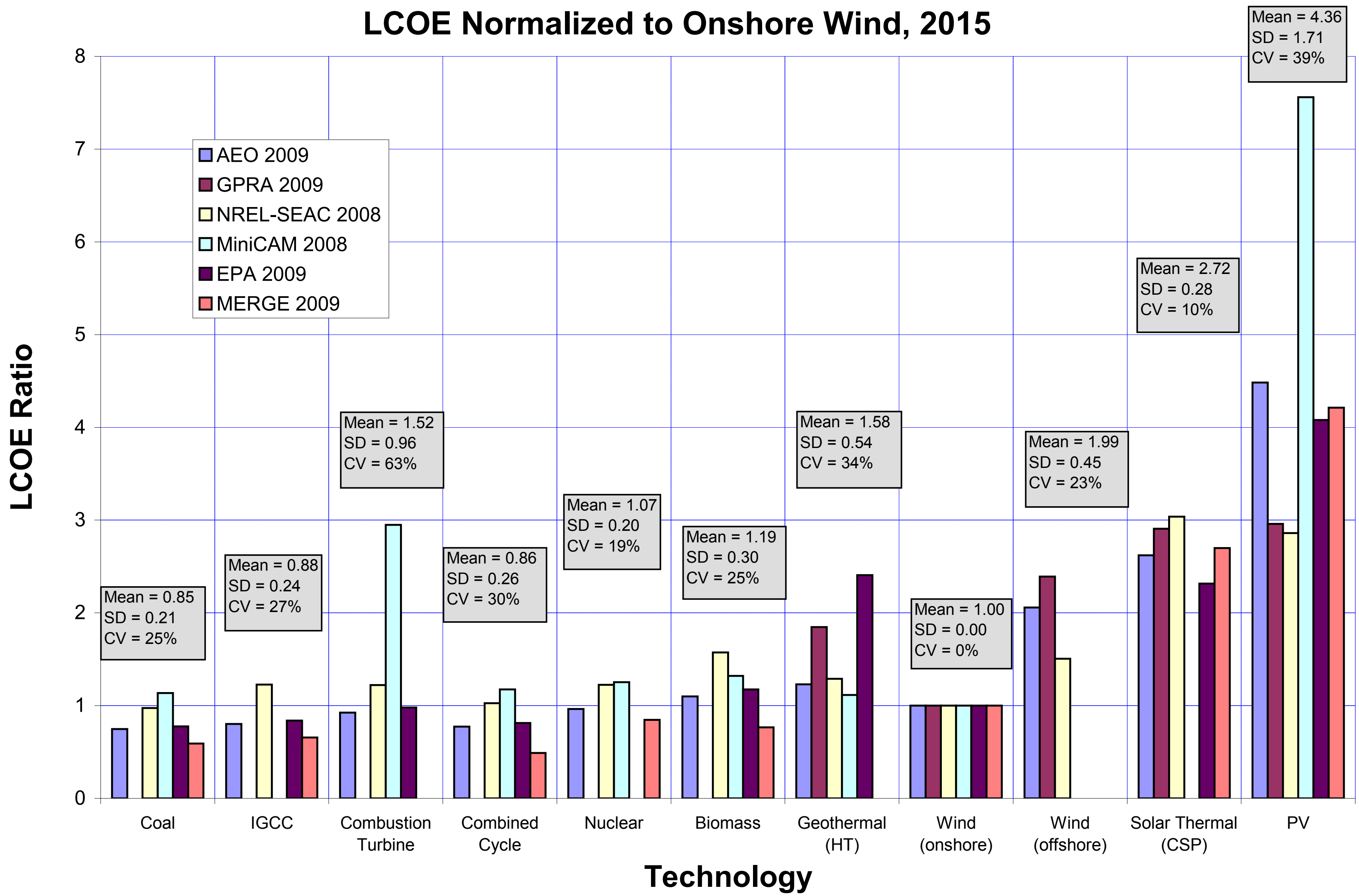


Figure 41. LCOE cost ratios relative to wind, 2015

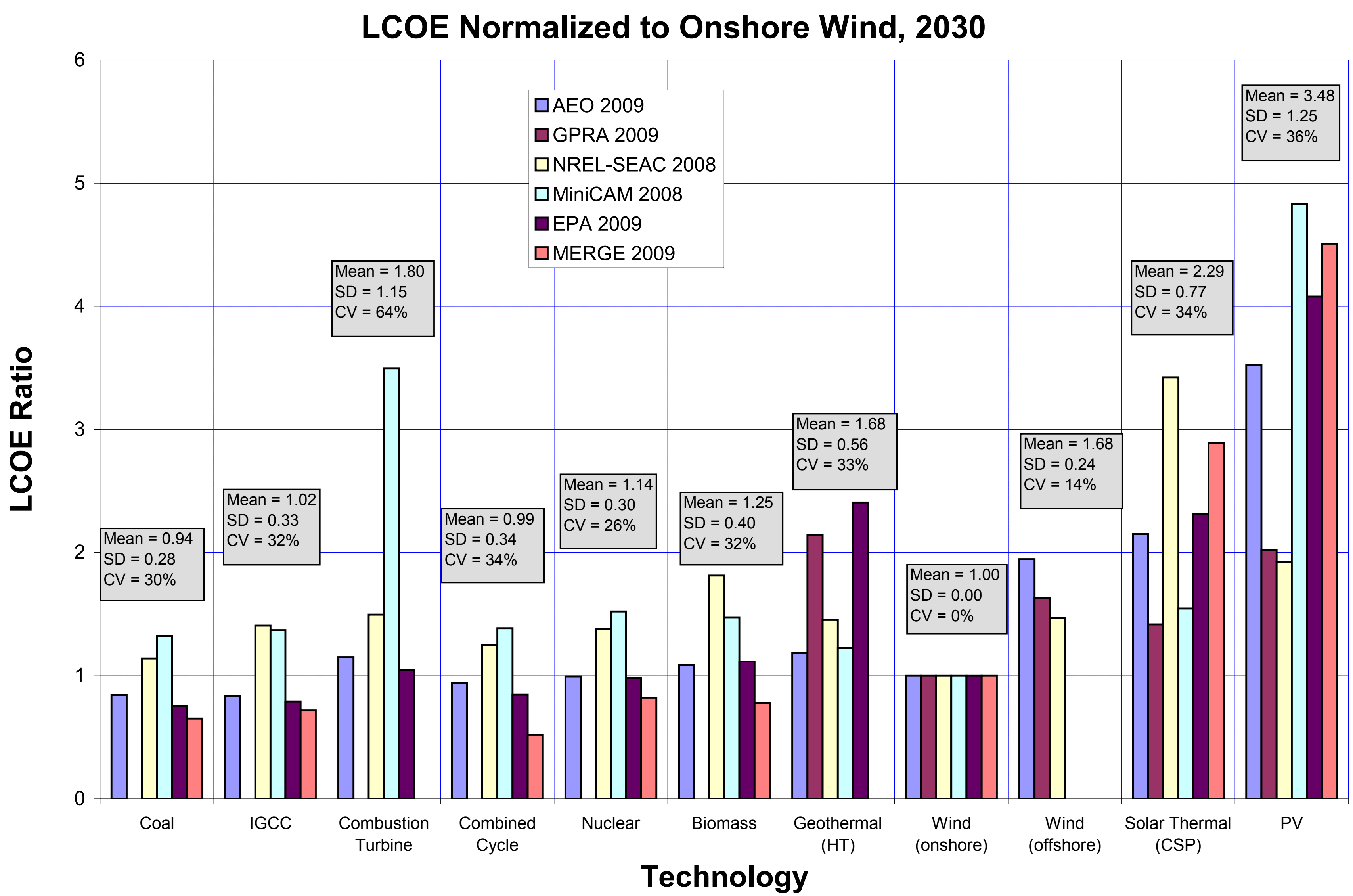


Figure 42. LCOE cost ratios relative to wind, 2030

4.2 Capital, O&M, and Fuel Costs (2015 and 2030)

The next 11 figures (Figure 43 to Figure 53) show the contribution of capital, O&M, and fuel to LCOE costs. The costs in these 11 figures correspond to 2015 and 2030, and all costs are expressed in 2007 real dollars.

Coal, Figure 43– Coal costs show slight changes between 2015 and 2030. The costs go down in the AEO and EPA data sets, rise in the NREL-SEAC and MERGE data sets, and remain constant in MiniCAM. As indicated, MERGE O&M costs are relatively high. This result should be viewed with caution, however, because O&M costs were not provided by EPRI. Rather, MERGE O&M costs were calculated based on selected cost values provided in EPRI literature, and it is possible that the actual O&M costs developed by EPRI are lower than the calculated quantities.

IGCC, Figure 44 – Cost trends for IGCC plants are similar to coal plants – AEO and EPA decline from 2015 to 2030, and NREL-SEAC and MERGE rise during this same time period. The online year for IGCC in MiniCAM is 2020, and an IGCC cost for 2015 is not reported in the MiniCAM data set. Like coal plants, the MERGE O&M contribution is high compared to other data sets.

Combustion Turbine, Figure 45 – The MiniCAM combustion turbine capital cost component is noticeably high. This result occurs because the MiniCAM combustion turbine is modeled as a peaking unit with a low capacity factor (10%).

Combined Cycle, Figure 46 – Costs remain relatively constant between 2015 and 2030, although the NREL-SEAC data set does show a noticeable increase in overall LCOE costs as a result of higher fuel costs. For all combined cycle plants, fuel costs are the largest component of LCOE.

Nuclear, Figure 47 – For nuclear, the AEO and NREL-SEAC data sets have costs that are all relatively close in 2015. The AEO data set does show an overall decline in LCOE between 2015 and 2030, whereas the NREL-SEAC data set has about the same total LCOE in both years. The MiniCAM data set is at the low end of the spectrum. One explanation for low MiniCAM costs is that the characteristics for MiniCAM are generally taken from the AEO 2008 publication (2007 calendar year data); while the other data sets generally have characteristics based on calendar year 2008 or 2009. There was a significant run-up in capital costs starting around 2007, and this capital cost increase is likely not captured in the MiniCAM data set. The MERGE data set shows the highest capital and O&M costs compared to the other data sets. Nuclear fuel costs (uranium) in all data sets are relatively constant.

Biomass, Figure 48 – Four of the data sets – AEO, MiniCAM, EPA, and MERGE – show LCOE declines between 2015 and 2030. In contrast, the NREL-SEAC data set shows a slight increase over this period.

Geothermal (hydrothermal), Figure 49 – For geothermal, wind, and solar resources there is no fuel cost and there are only two contributors to LCOE – capital and O&M. The one noticeable outlier is the capital cost for the EPA 2009 data set. In this data set, there is a wide range of geothermal overnight capital costs depending on site conditions. An average value was used for the LCOE calculations, but the average capital cost was still significantly higher than other data sets. This high capital cost is the primary driver behind the high EPA geothermal LCOE values.

Onshore Wind, Figure 50 – MERGE O&M and capital costs are high compared to the other data sets. O&M costs for all other data sets are relatively consistent. The GPRA 2009 data set has the lowest capital costs and resulting LCOE values for 2015 and 2030.

Offshore Wind, Figure 51 – Three of the data sets – AEO, GPRA, and NREL-SEAC –report offshore wind costs. The AEO 2009 data set has the largest capital cost and the highest LCOE values. The GPRA 2009 data set shows a relatively large reduction in O&M between 2015 and 2030. In 2015, the LCOE for GPRA is higher than NREL-SEAC, but by 2030, the GPRA LCOE is lower than NREL-SEAC.

Solar Thermal, Figure 52 – For solar thermal, the MERGE data set has relatively high O&M costs and relatively high capital costs. Within a given year (2015 or 2030), the GPRA data set has the lowest LCOE (MiniCAM online year for solar thermal is 2020 – no MiniCAM solar thermal result for 2015). Two of the data sets – GPRA and MiniCAM – have thermal energy storage integrated with solar thermal plants, while the other four data sets do not. Even with energy storage, the capital costs in the GPRA and MiniCAM data sets are at the low end compared to the other data sets, which do not incorporate thermal energy storage.

PV, Figure 53 – Like solar thermal, the MERGE data set has relatively high O&M costs and relatively high capital costs. With the exception of the MERGE data set, O&M costs for PV technologies are quite small relative to PV capital costs.

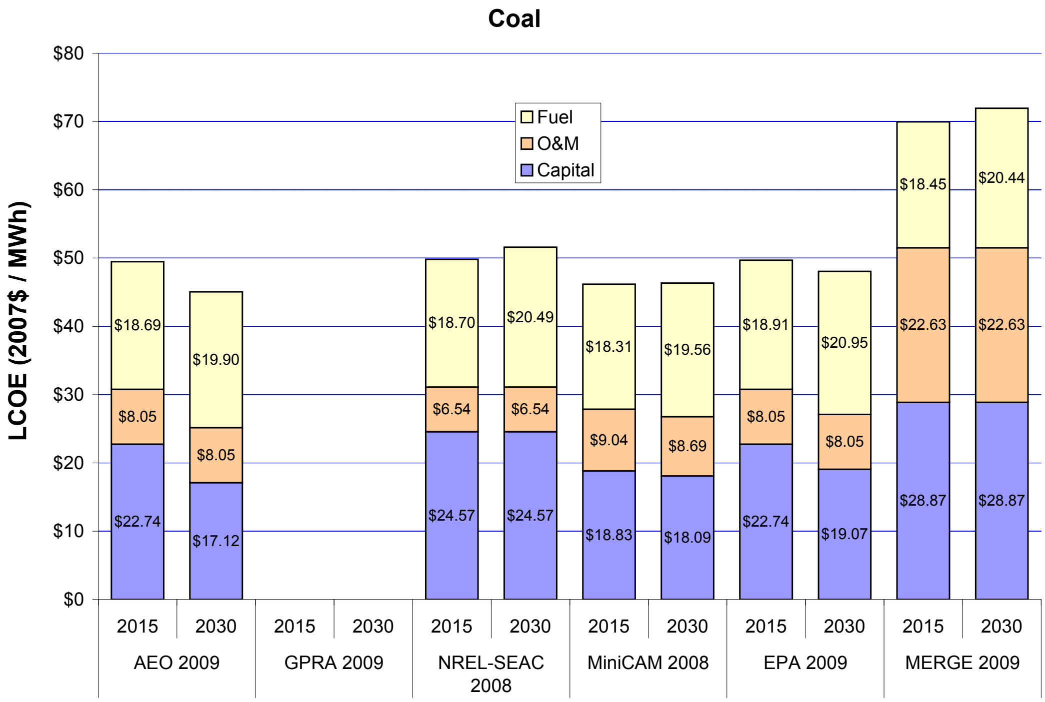


Figure 43. Capital, fuel, and O&M costs—coal

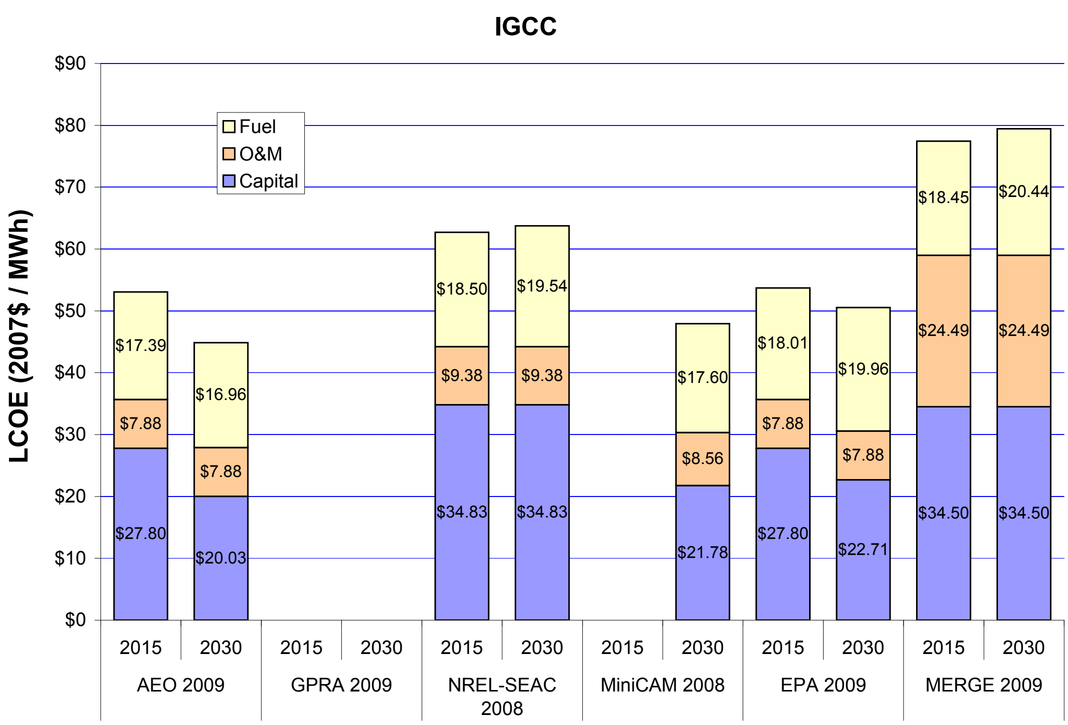


Figure 44. Capital, fuel, and O&M costs—IGCC

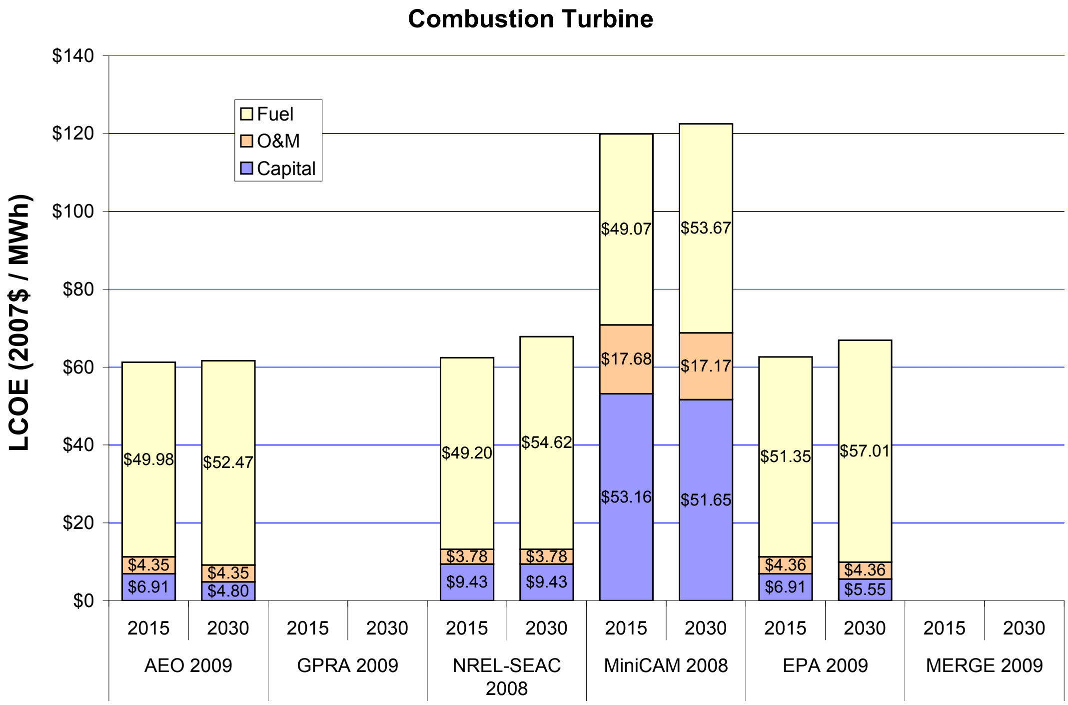


Figure 45. Capital, fuel, and O&M costs—combustion turbine

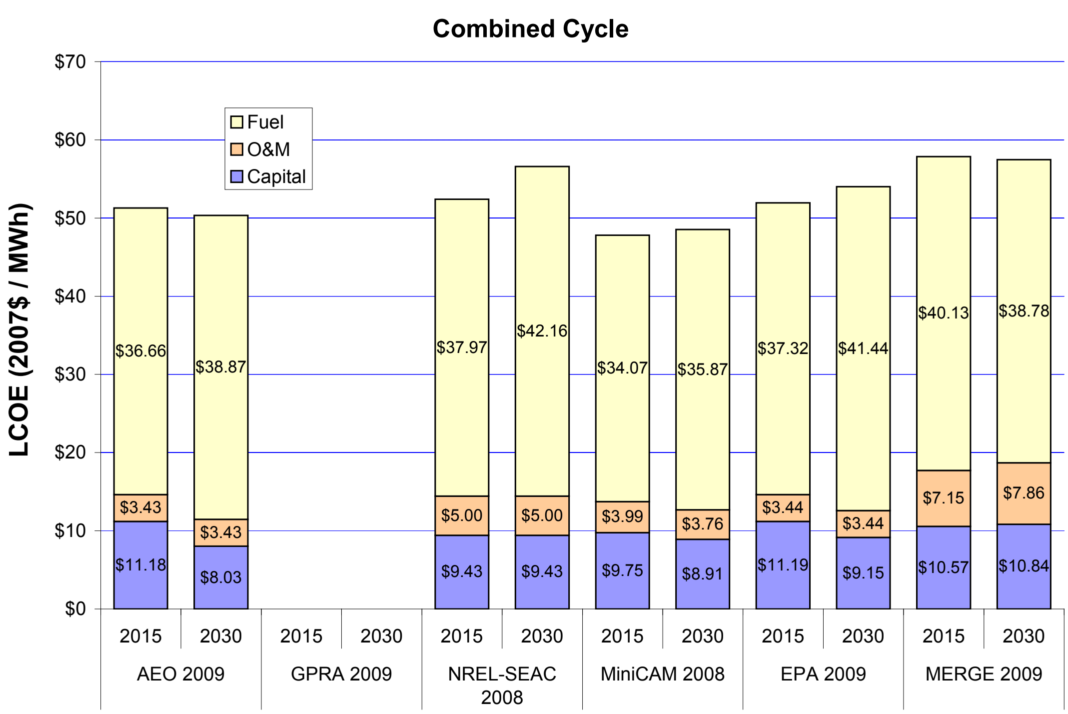


Figure 46. Capital, fuel, and O&M costs—combined cycle

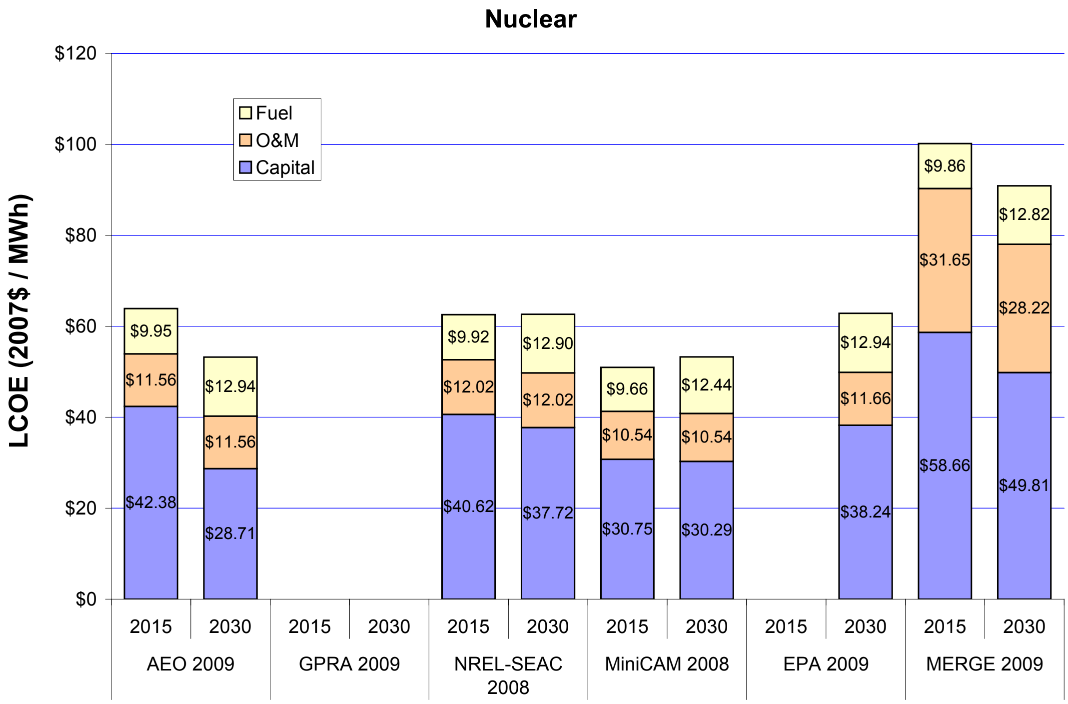


Figure 47. Capital, fuel, and O&M costs—nuclear

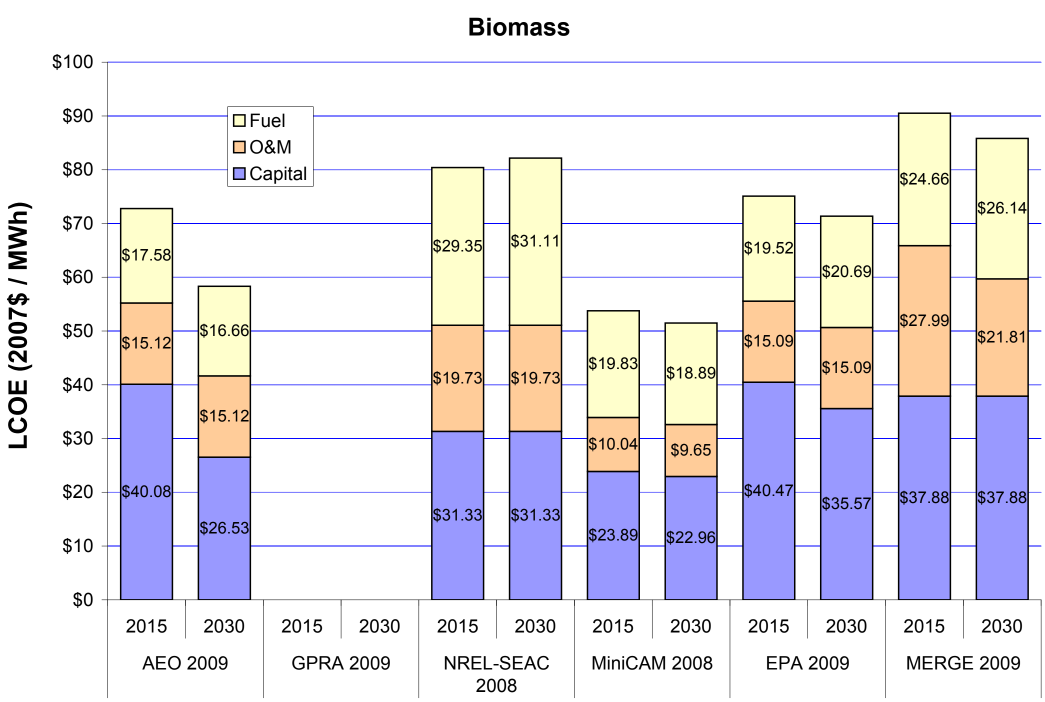


Figure 48. Capital, fuel, and O&M costs—biomass

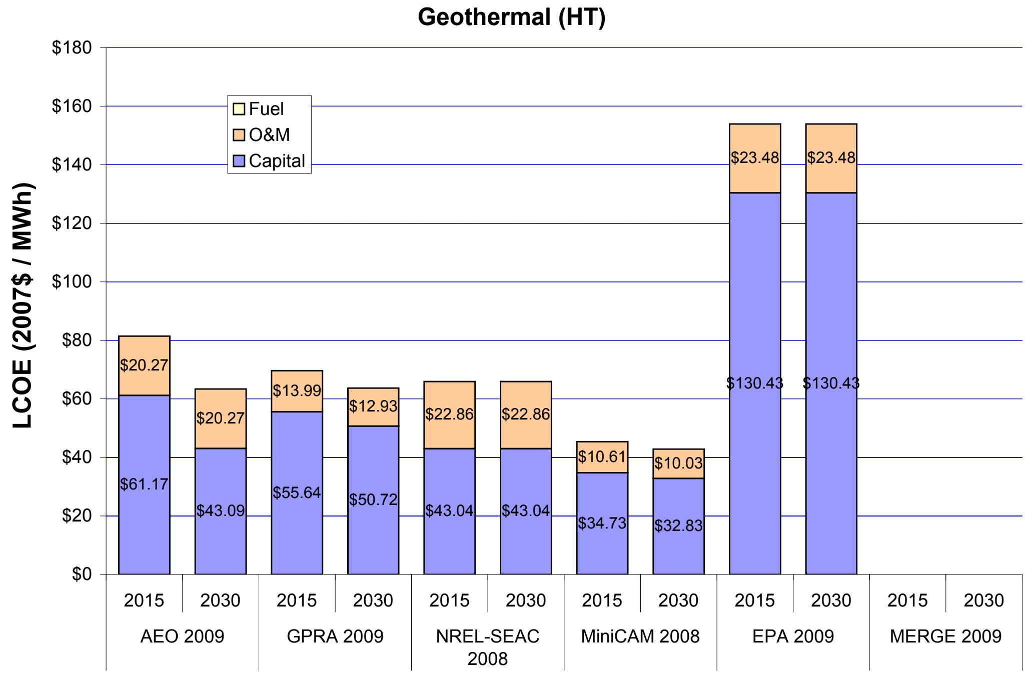


Figure 49. Capital, fuel, and O&M costs—geothermal (HT)

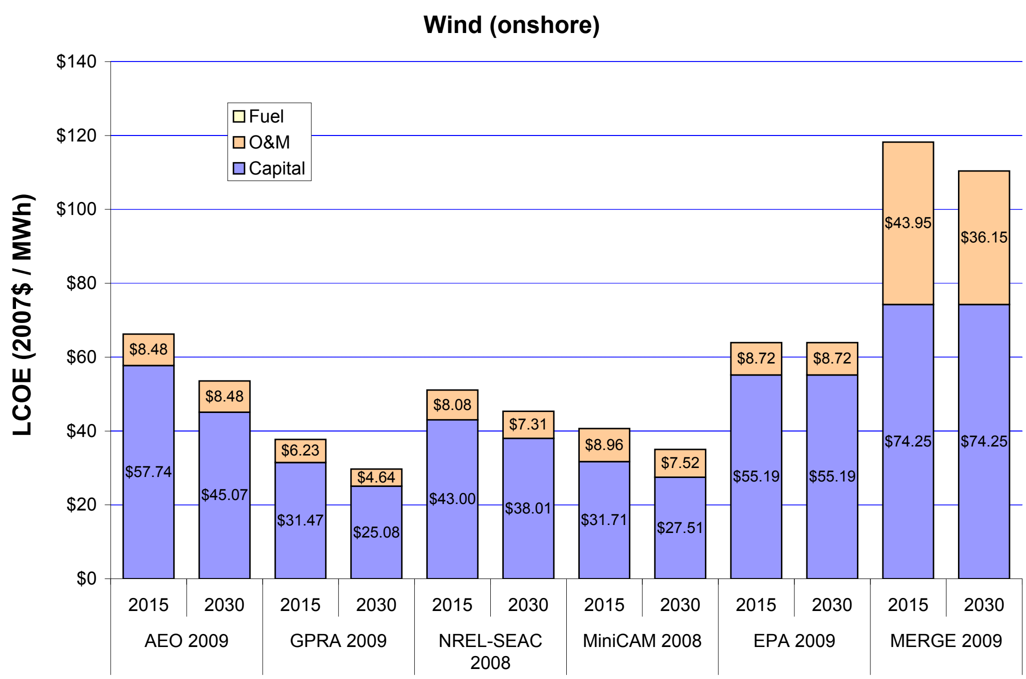


Figure 50. Capital, fuel, and O&M costs—wind (onshore)

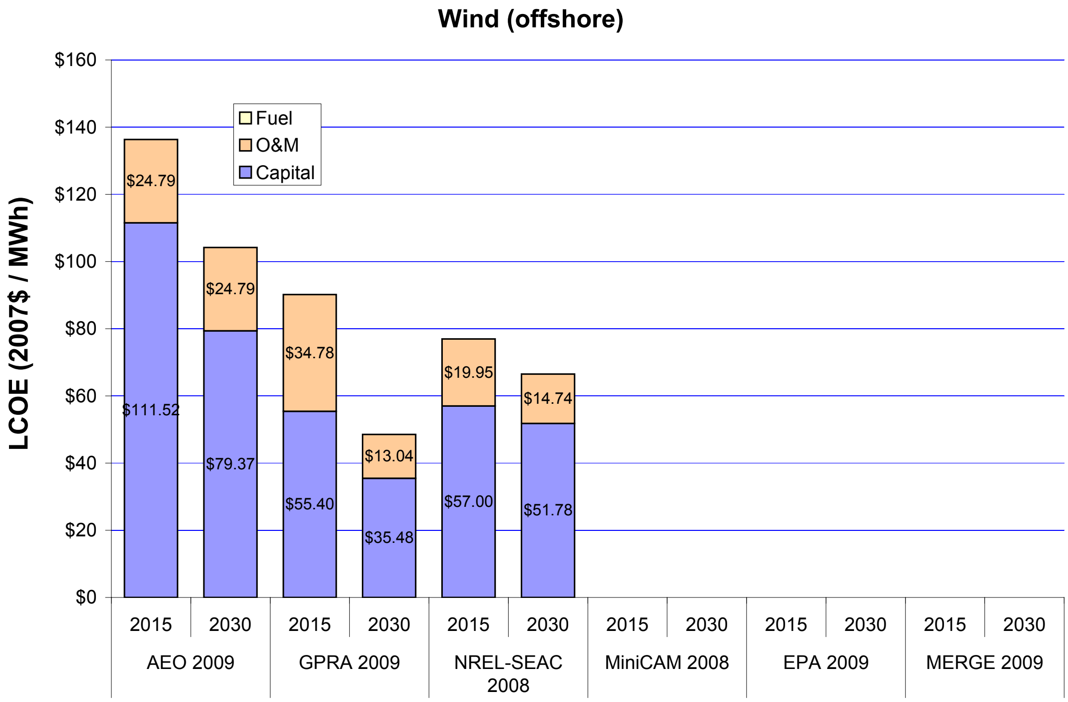


Figure 51. Capital, fuel, and O&M costs—wind (offshore)

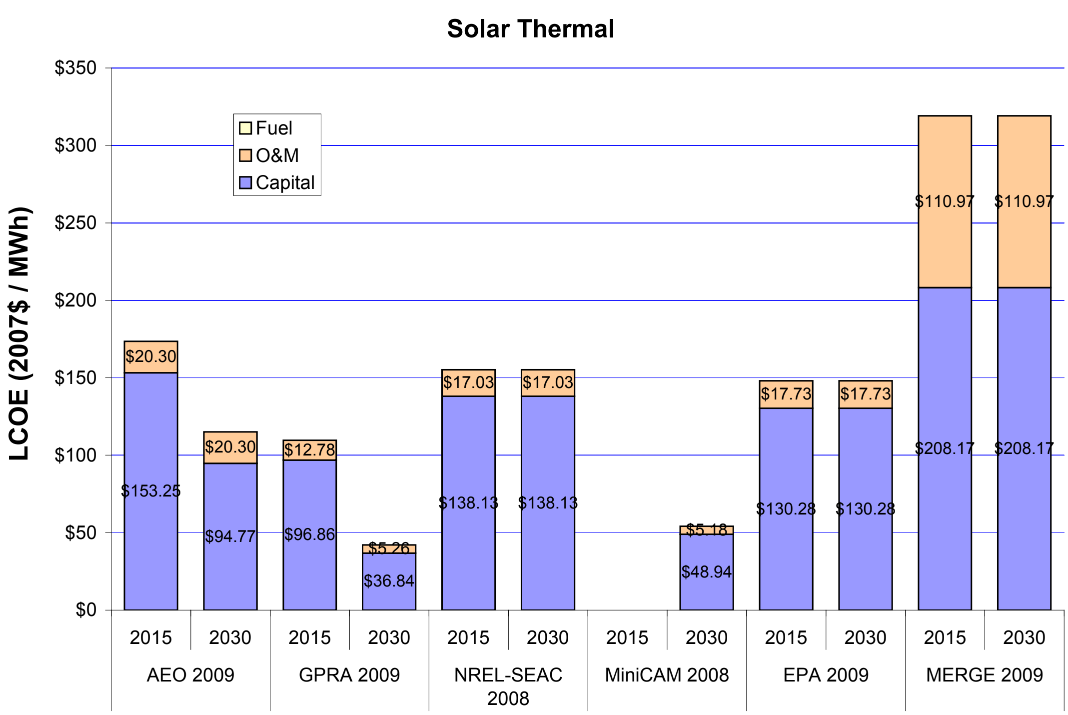


Figure 52. Capital, fuel, and O&M costs—solar thermal (CSP)

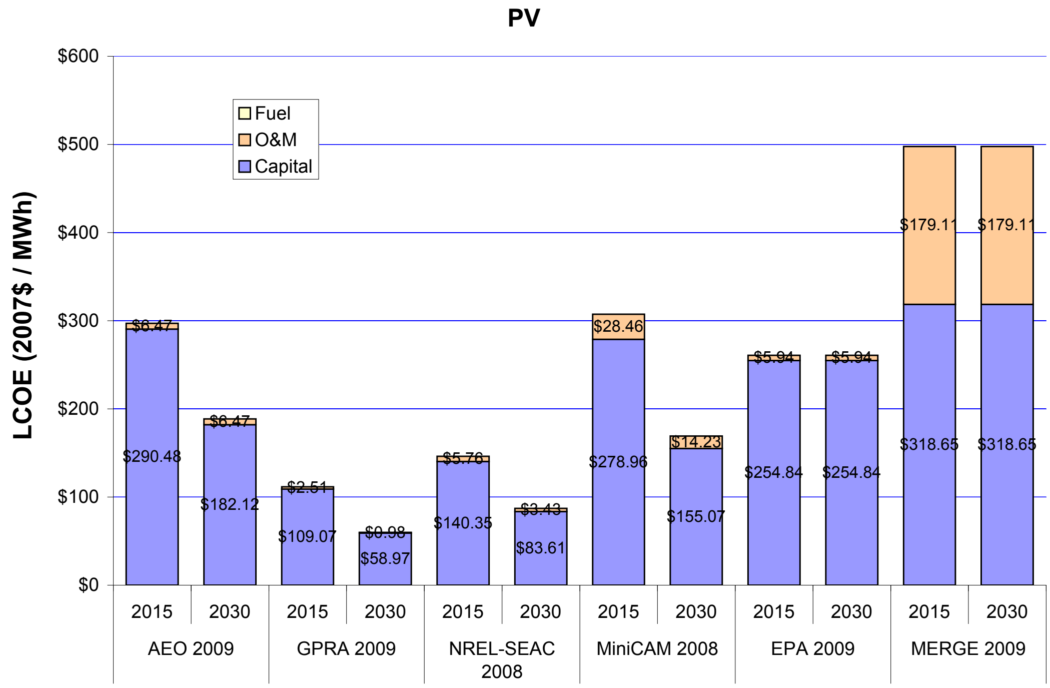


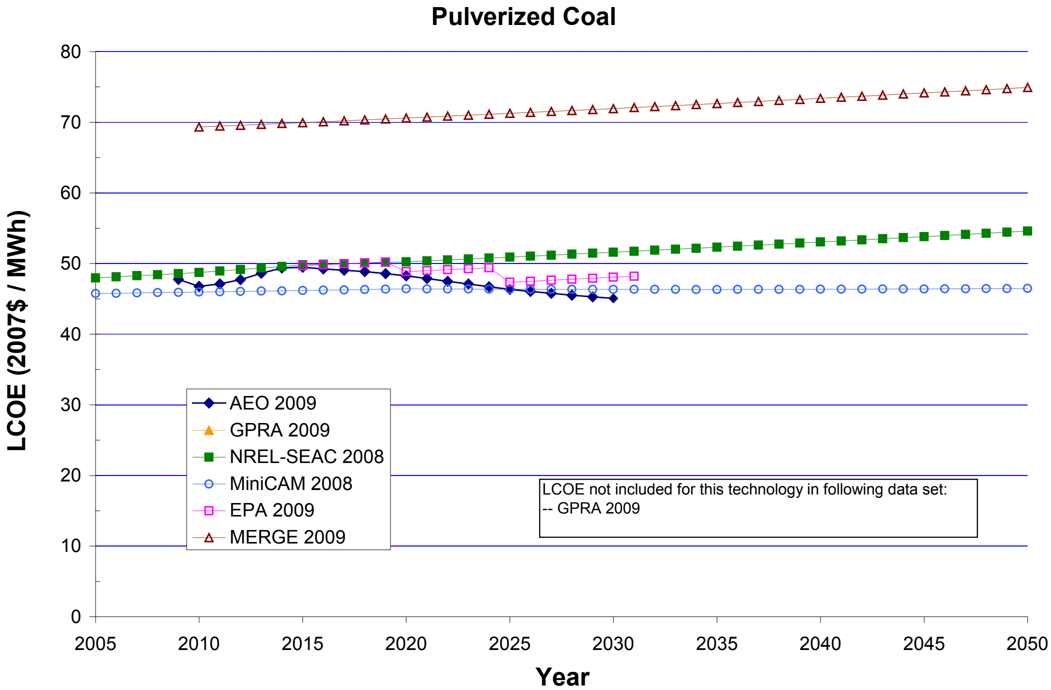
Figure 53. Capital, fuel, and O&M costs—PV

4.3 Time Trends (2005 through 2050)

LCOE costs for 2005 through 2050 are shown in the next 11 figures (Figure 54 through Figure 64).

- **Coal** – As indicated, with the exception of the MERGE data set, the LCOE trends remain near $50/MWh through 2050. The MERGE costs are in the range of $70 to $80/MWh. The high MERGE costs result from relatively high capital costs and relatively high O&M costs compared to the other data sets.
- **IGCC** – For IGCC plants, the MERGE data set has the highest LCOE costs, followed by the NREL-SEAC data set. The AEO, EPA, and MiniCAM data sets show similar cost trends, which decline over time as a result of learning (i.e., capital costs decline over time).
- **Combustion Turbine** – For combustion turbines, the MiniCAM data set is the highest due to the low capacity factor in this data set (10%). The other data sets show similar cost trends
- **Combined Cycle** – For combined cycle plants, LCOE values generally trend upward in most data sets. The AEO and MiniCAM data sets show stable prices after about 2020, due to offsetting impacts of lower capital costs but increasing fuel costs.
- **Nuclear** – For nuclear plants, MERGE costs are the highest. The other data sets show relatively similar LCOE costs through 2050.

- **Biomass** –The MiniCAM data set shows the lowest LCOE costs. The MERGE data set is the highest, followed by the NREL-SEAC data set. The AEO and EPA data sets fall between the NREL-SEAC and MiniCAM values.
- **Geothermal** – The geothermal category is intended to represent geothermal hydrothermal plants. However, the EPA data set may be based on EGS as well as hydrothermal characteristics, which could explain the unusually high LCOE costs for the EPA data set. The fluctuations in the AEO data set result from the methodology used by EIA, which involves analyzing expected plant construction costs based on site-specific geothermal resources.
- **Wind (onshore)** – For onshore wind, the MERGE data set has the highest LCOE costs. The other data sets show similar LCOE trends.
- **Wind (offshore)** – Three data sets – AEO 2009, NREL-SEAC 2008, and GPRA 2009 – have offshore wind. The GPRA LCOE costs are clearly the highest in early years, but then fall to the lowest costs in later years (after 2025). The AEO costs are the highest relative to the same years for the GPRA and NREL-SEAC data sets.
- **Solar Thermal** – MERGE LCOE costs are highest. The GPRA and MiniCAM costs are the lowest, and the other data sets fall in between. It is interesting to note that the EPA and NREL-SEAC data sets show no change starting from around 2015 and beyond. This constant LCOE cost results from constant capital cost and constant O&M cost assumptions.
- **PV** – Like solar thermal, the MERGE costs are the highest. The MiniCAM costs start near the MERGE costs in 2005, but then quickly fall to levels similar to the other data sets. The GPRA and NREL-SEAC data sets have the lowest costs compared to the other data sets (GPRI generally lower than NREL-SEAC).



•

Figure 54. LCOE—coal

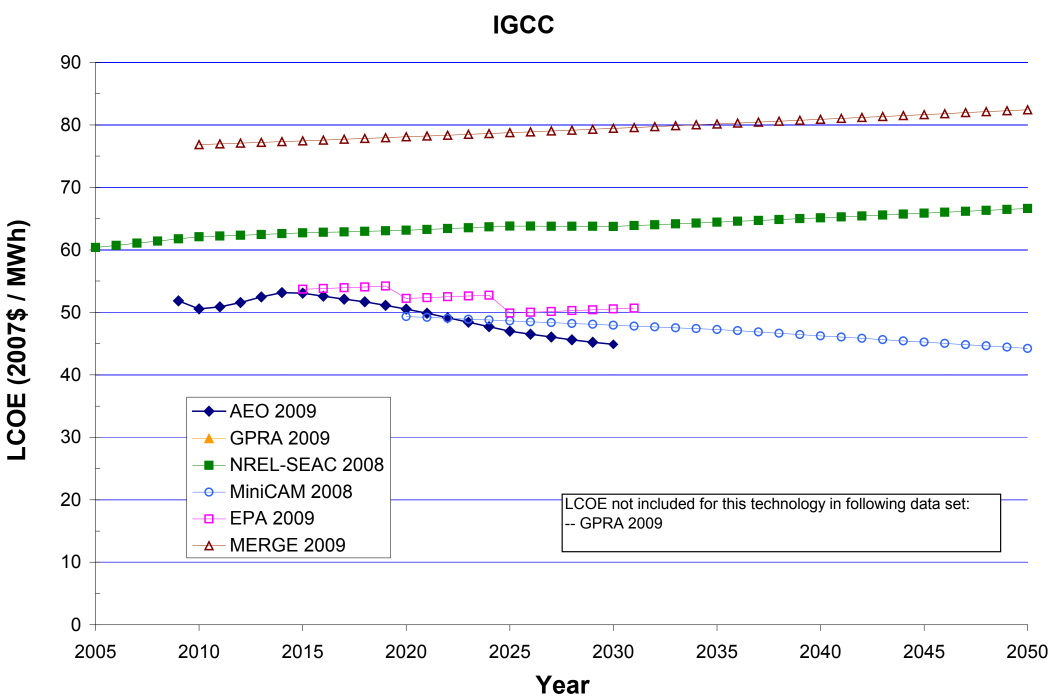


Figure 55. LCOE—IGCC

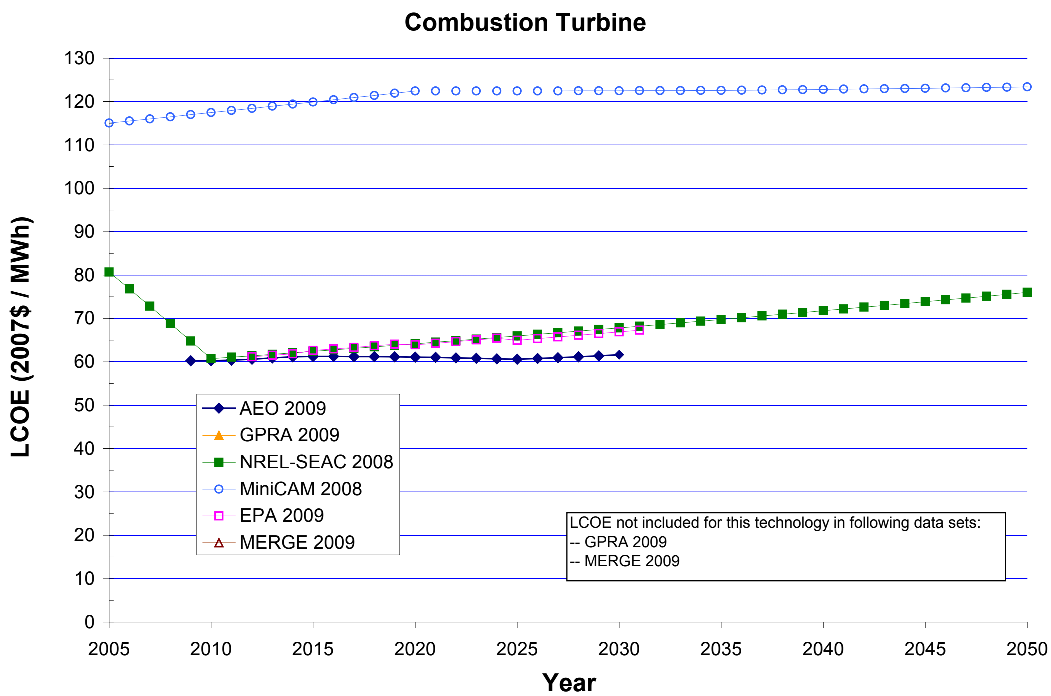


Figure 56. LCOE—combustion turbine

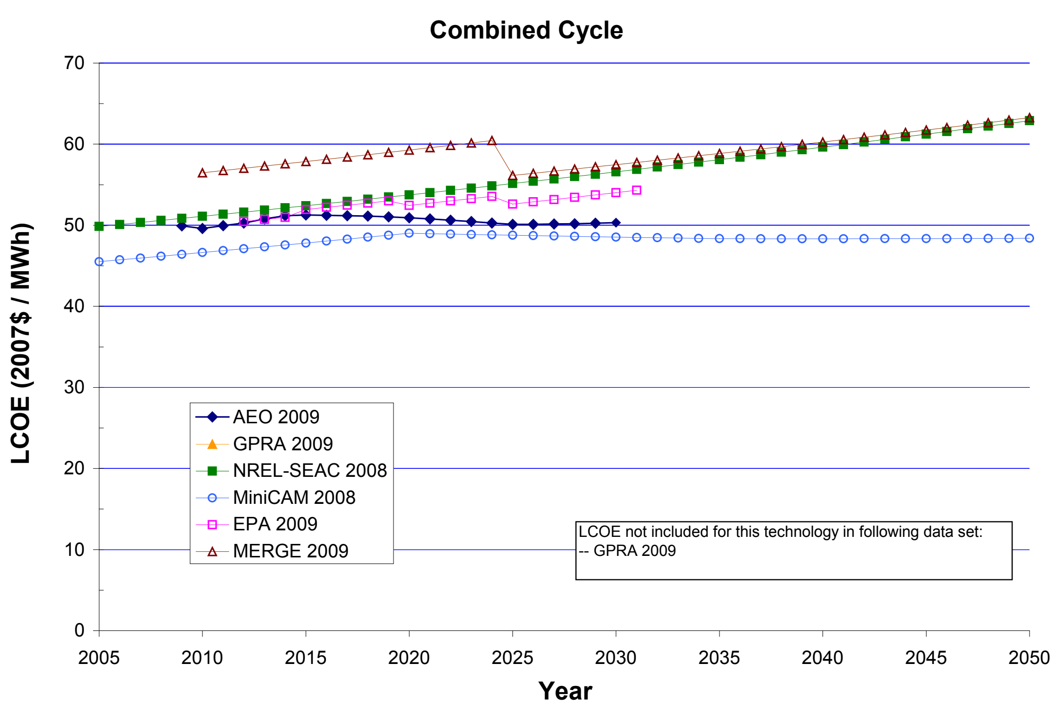


Figure 57. LCOE—combined cycle

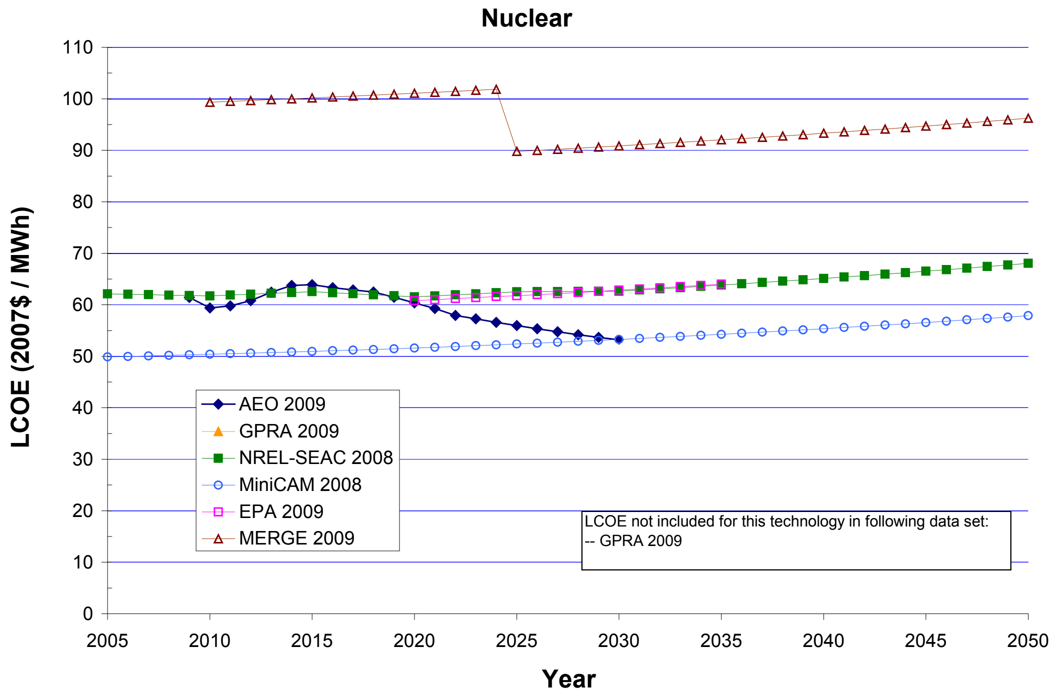


Figure 58. LCOE—nuclear

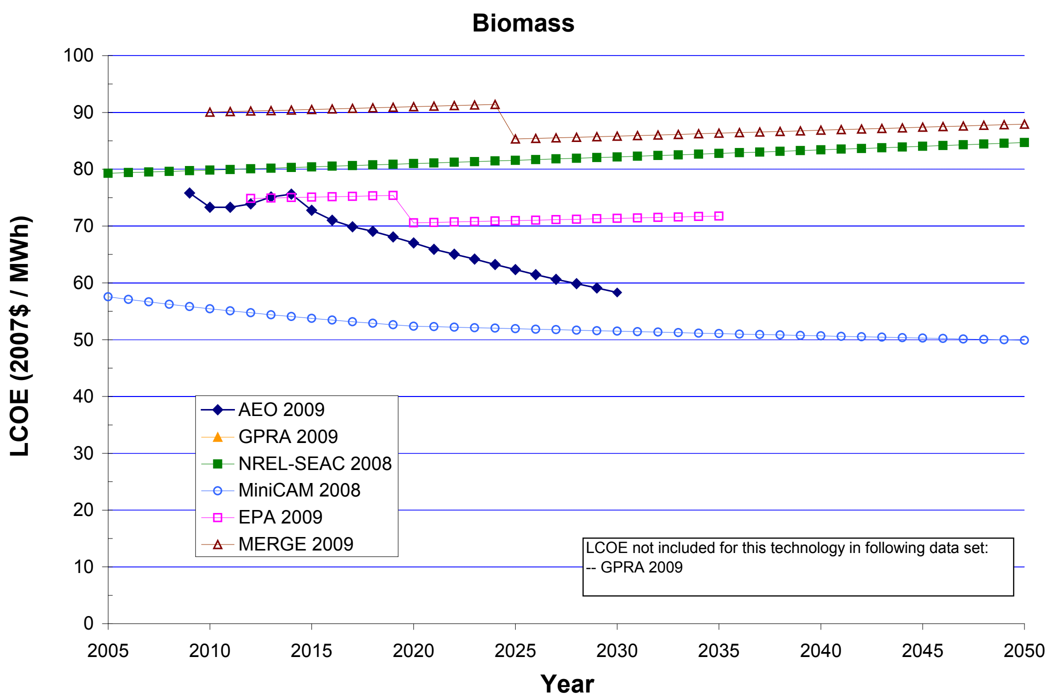


Figure 59. LCOE—biomass

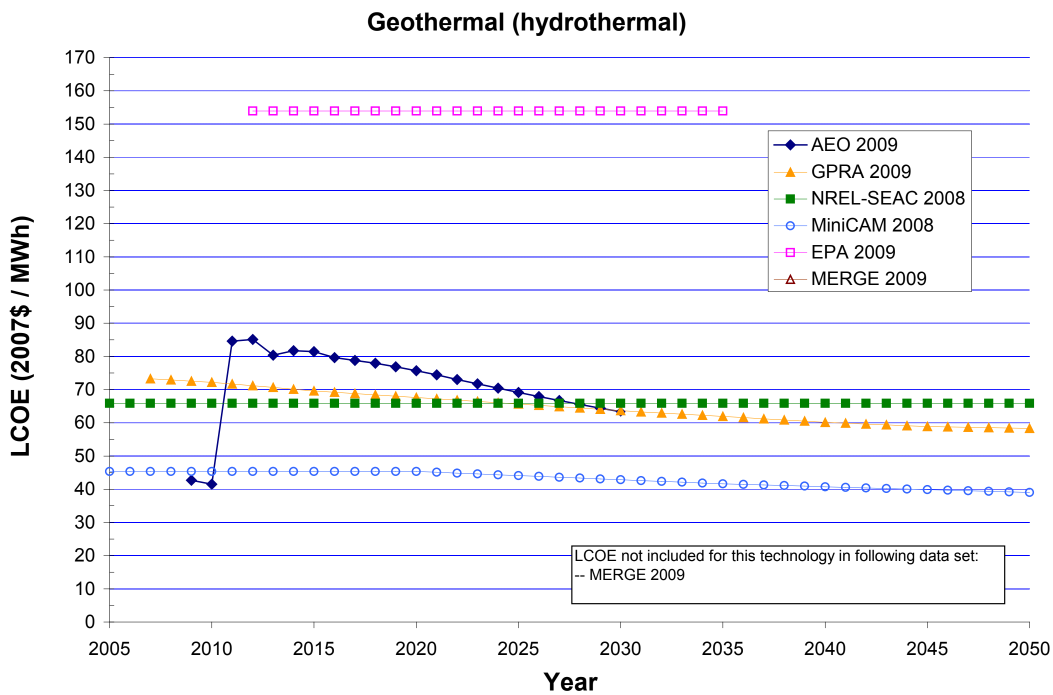


Figure 60. LCOE—geothermal (HT)

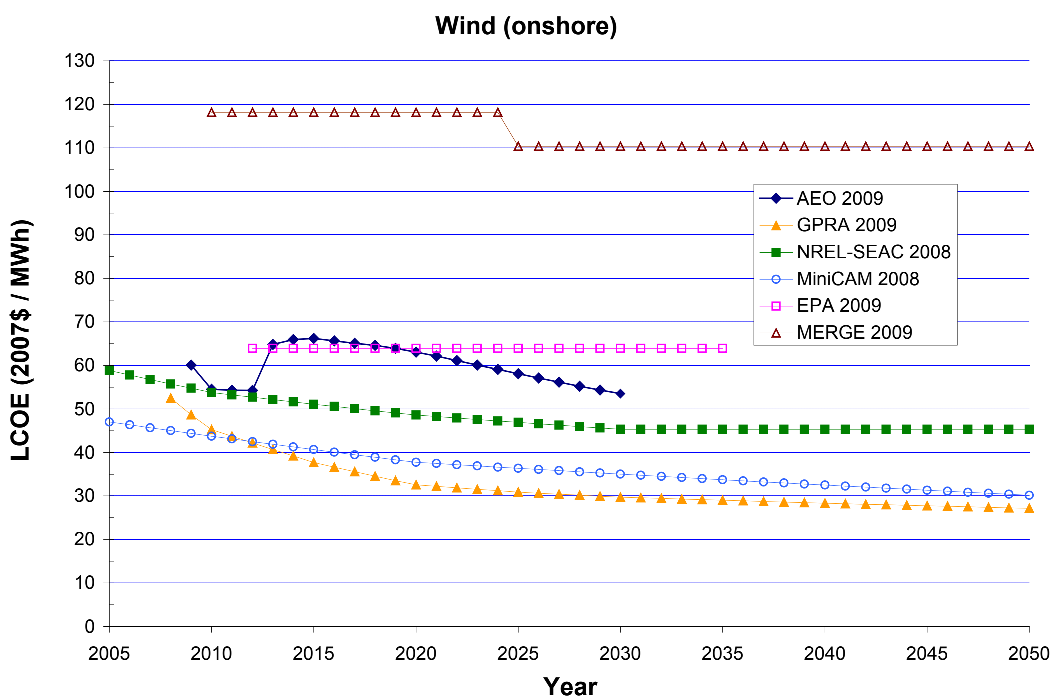


Figure 61. LCOE—wind (onshore)

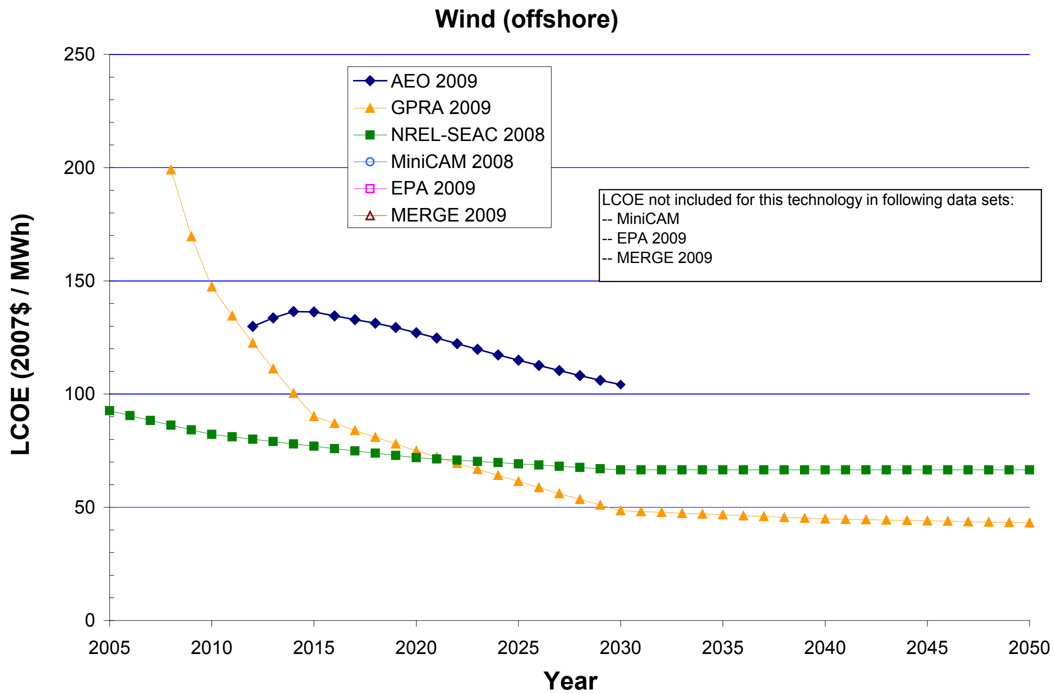


Figure 62. LCOE—wind (offshore)

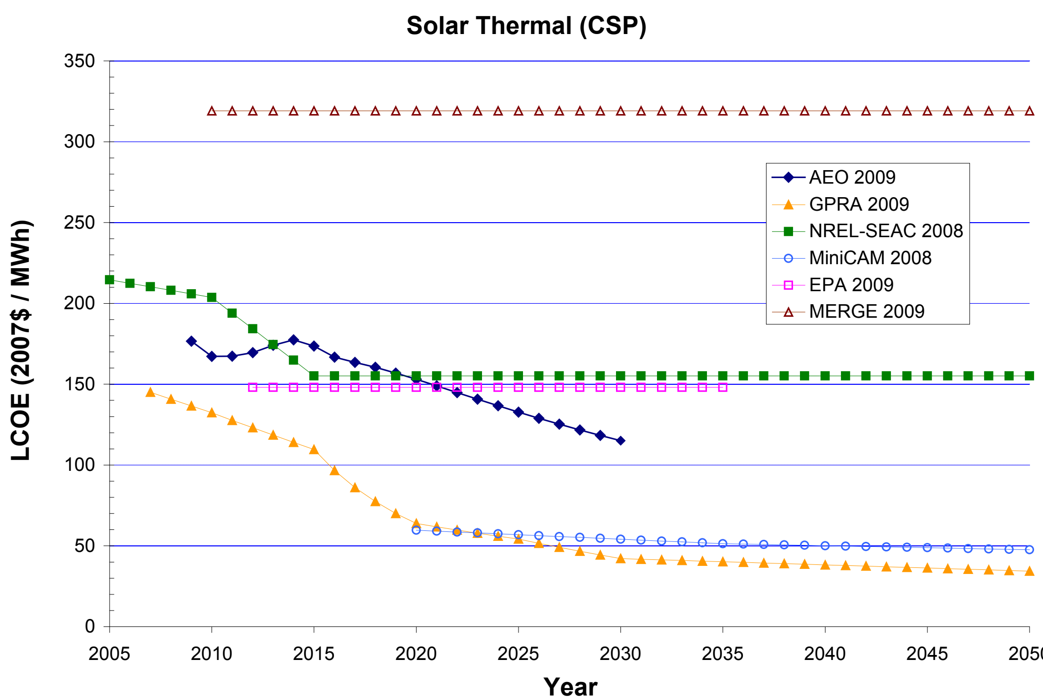


Figure 63. LCOE—solar thermal (CSP)

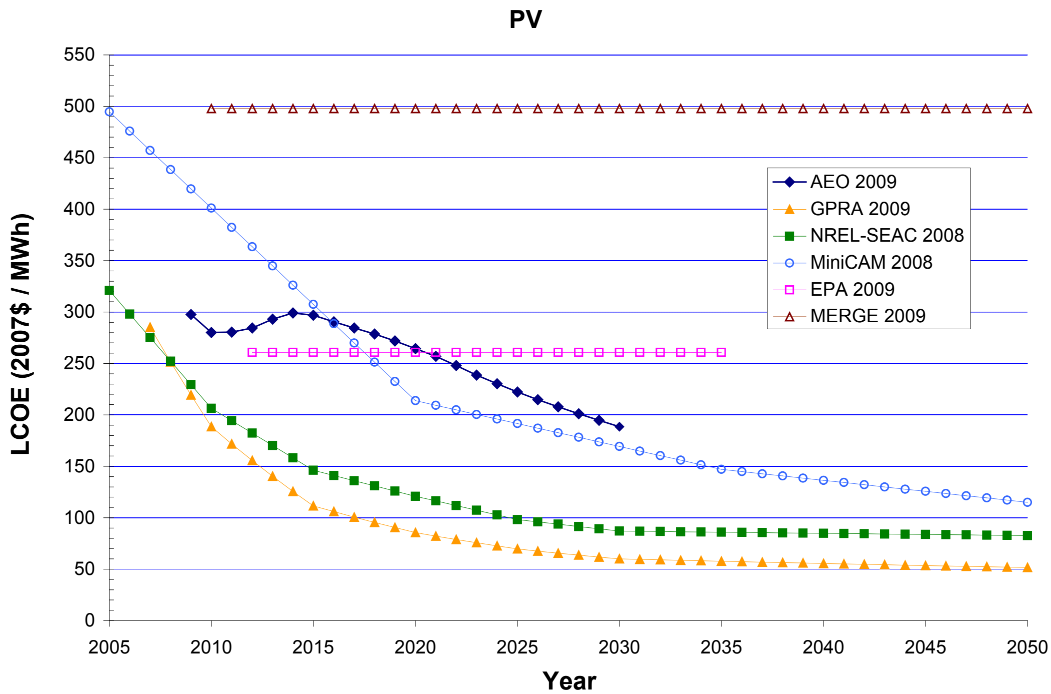


Figure 64. LCOE—PV

4.4 Impact of Equipment Costs

Estimates were developed for the fraction of equipment costs that contribute to the capital cost component of power generation technologies. Equipment is defined to include all site construction materials as well as all power generation systems delivered to the plant site. The estimates for the fraction of equipment costs are shown in Appendix I. Calculations were then completed to determine the sensitivity of the LCOE baseline values in 2015 to 10%, 20%, and 50% changes in the equipment cost. Figure 65 shows the impact of a 10% change, and Figure 66 shows the impact of a 50% change.

As indicated in Figure 65, a 10% change in the equipment cost changes the LCOE values from approximately 1% to 6%. The larger impacts occur for wind and solar technologies where equipment costs account for a larger fraction of capital costs compared to the other power generation technologies.

The impacts of a 50% increase in equipment costs are shown in Figure 66. The trends are similar to the 10% case, with wind and solar technologies showing the highest sensitivity to changes in equipment costs.

4.5 Impact of Labor Costs

The impact of labor costs on baseline LCOE values is shown in Figure 67 (10% change) and Figure 68 (50% change). A 10% increase in labor cost increases LCOE costs by a little over 3% for geothermal technologies. The impact is lower for other technologies, and quite small for a couple of technologies. For example, a 10% increase in labor has less than a 0.5% impact on LCOE costs for combustion turbine and combined cycle technologies.

The impact of a 50% increase in labor is shown in Figure 68. Like the 10% case, LCOE values for geothermal technologies are the most sensitive, and LCOE values for combustion turbine and combined cycle technologies are the least sensitive.

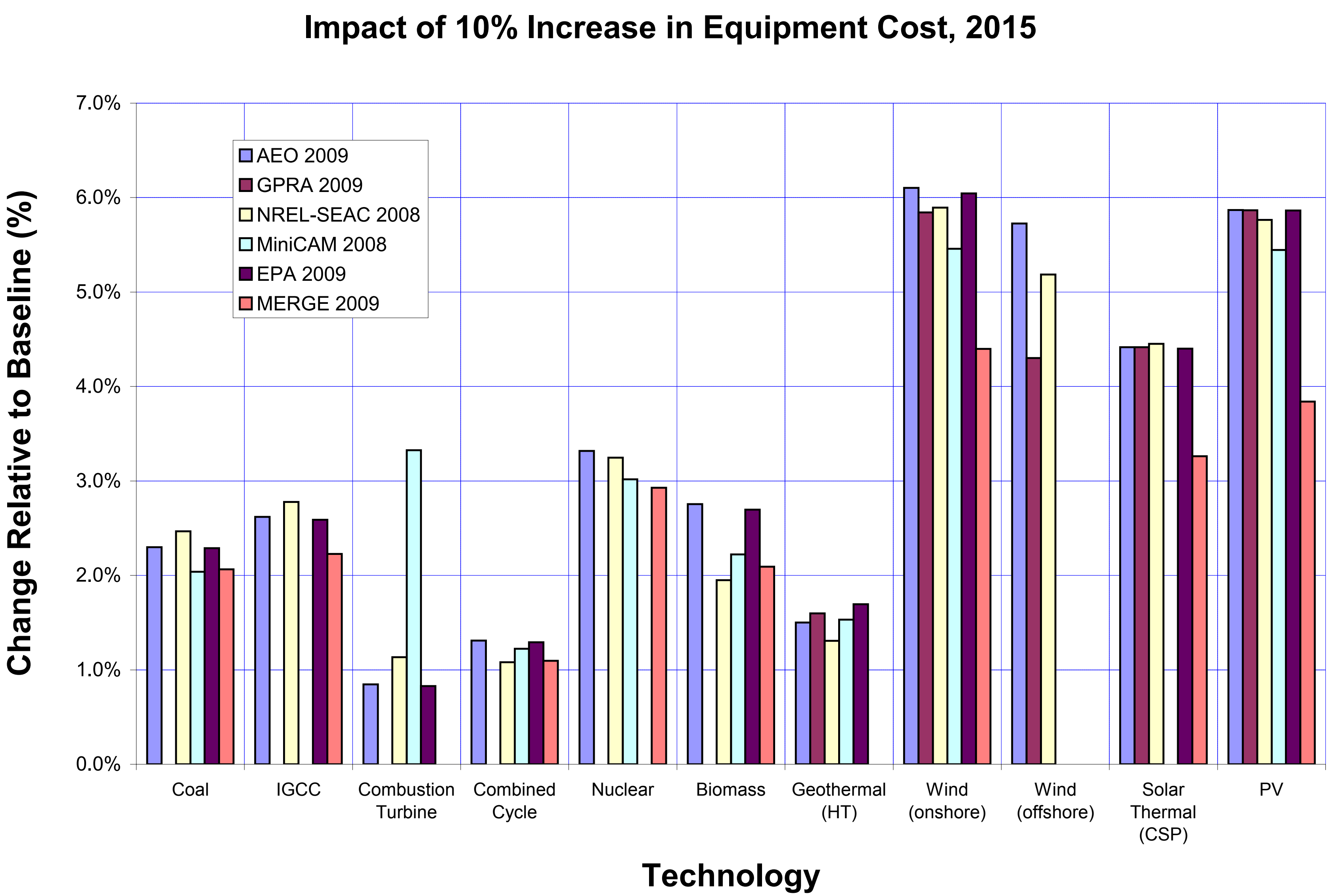


Figure 65. Impact on LCOE of equipment cost, 10% change

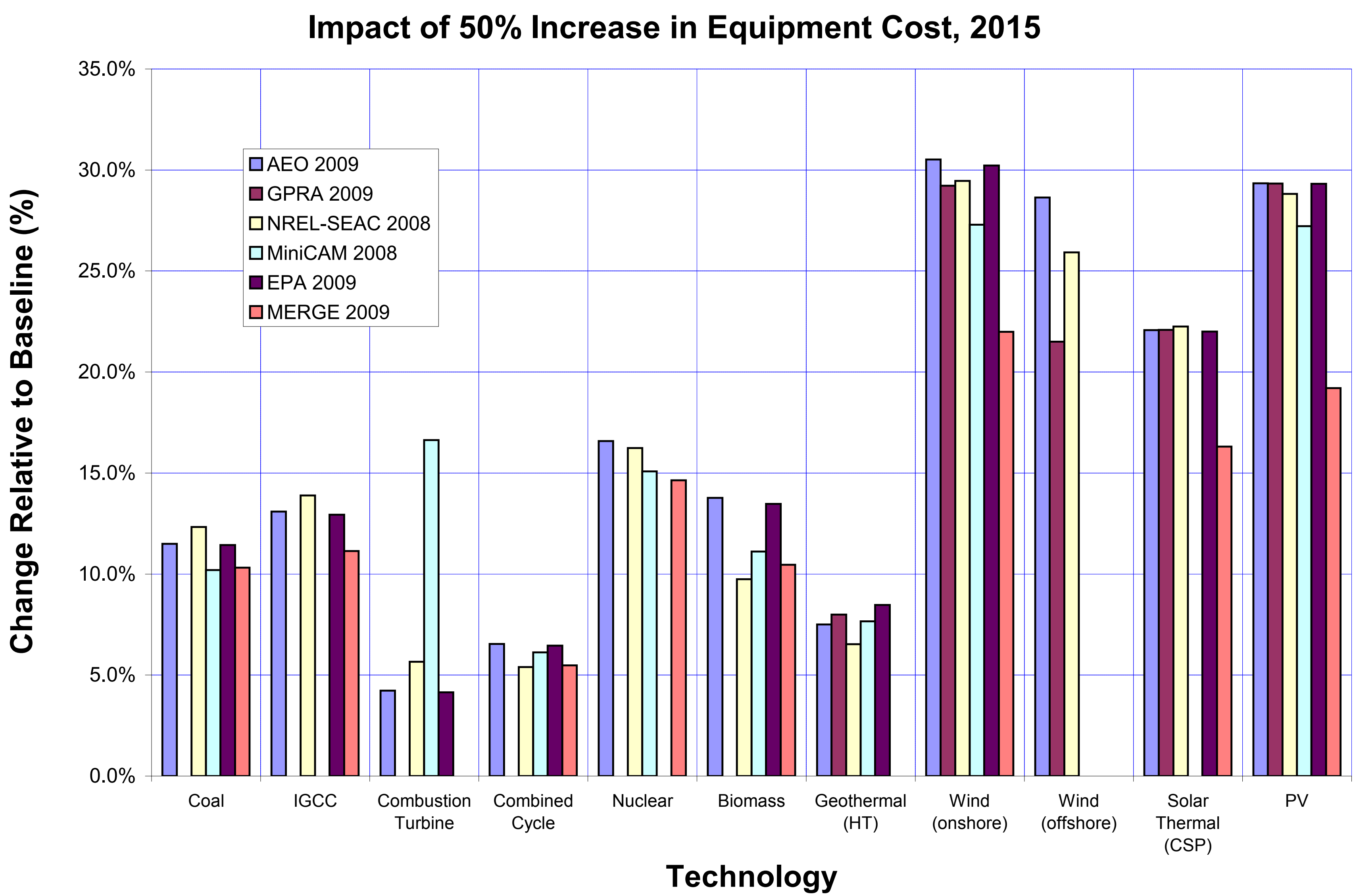


Figure 66. Impact on LCOE of equipment cost, 50% change

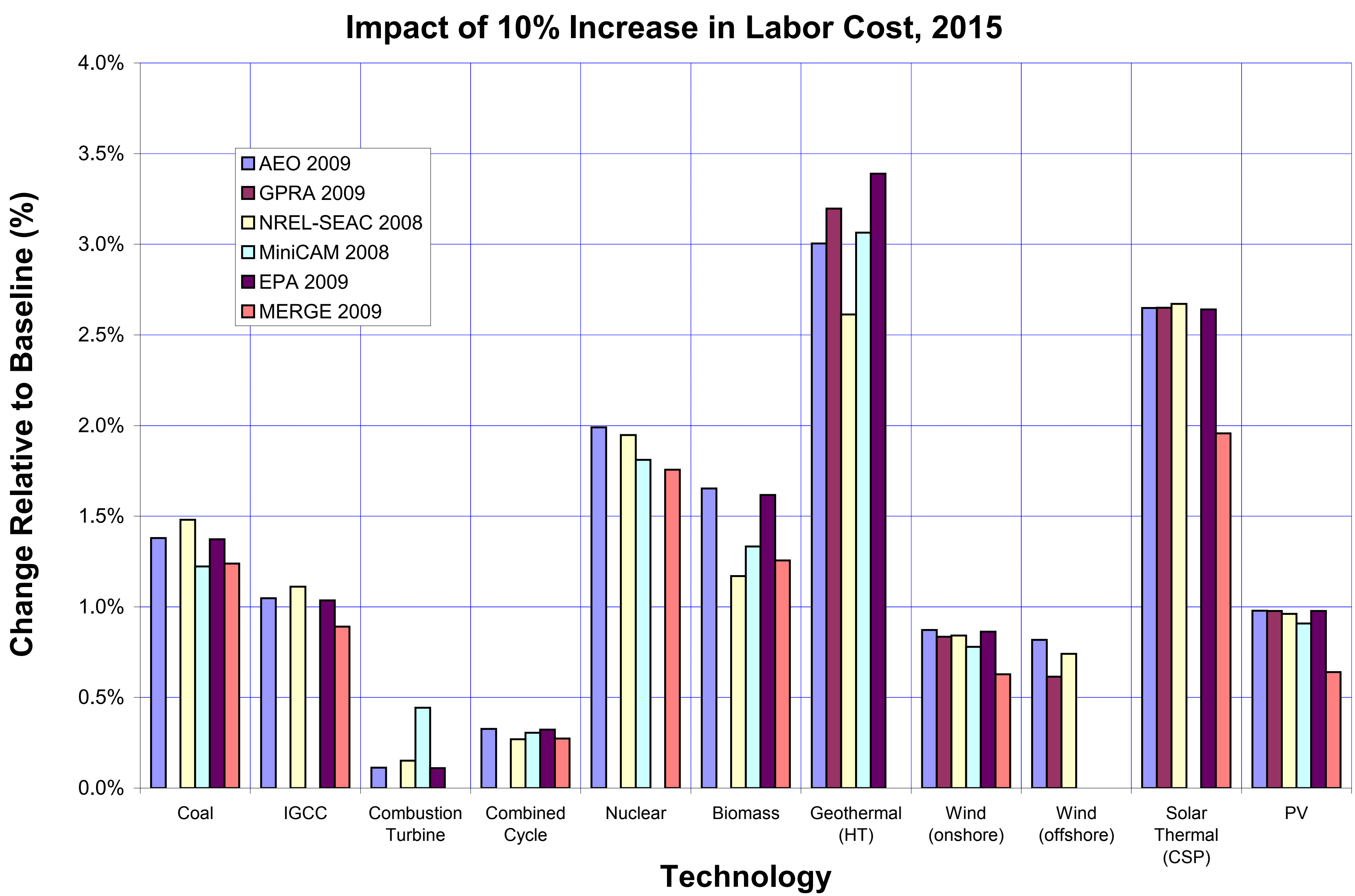


Figure 67. Impact on LCOE of labor cost, 10% change

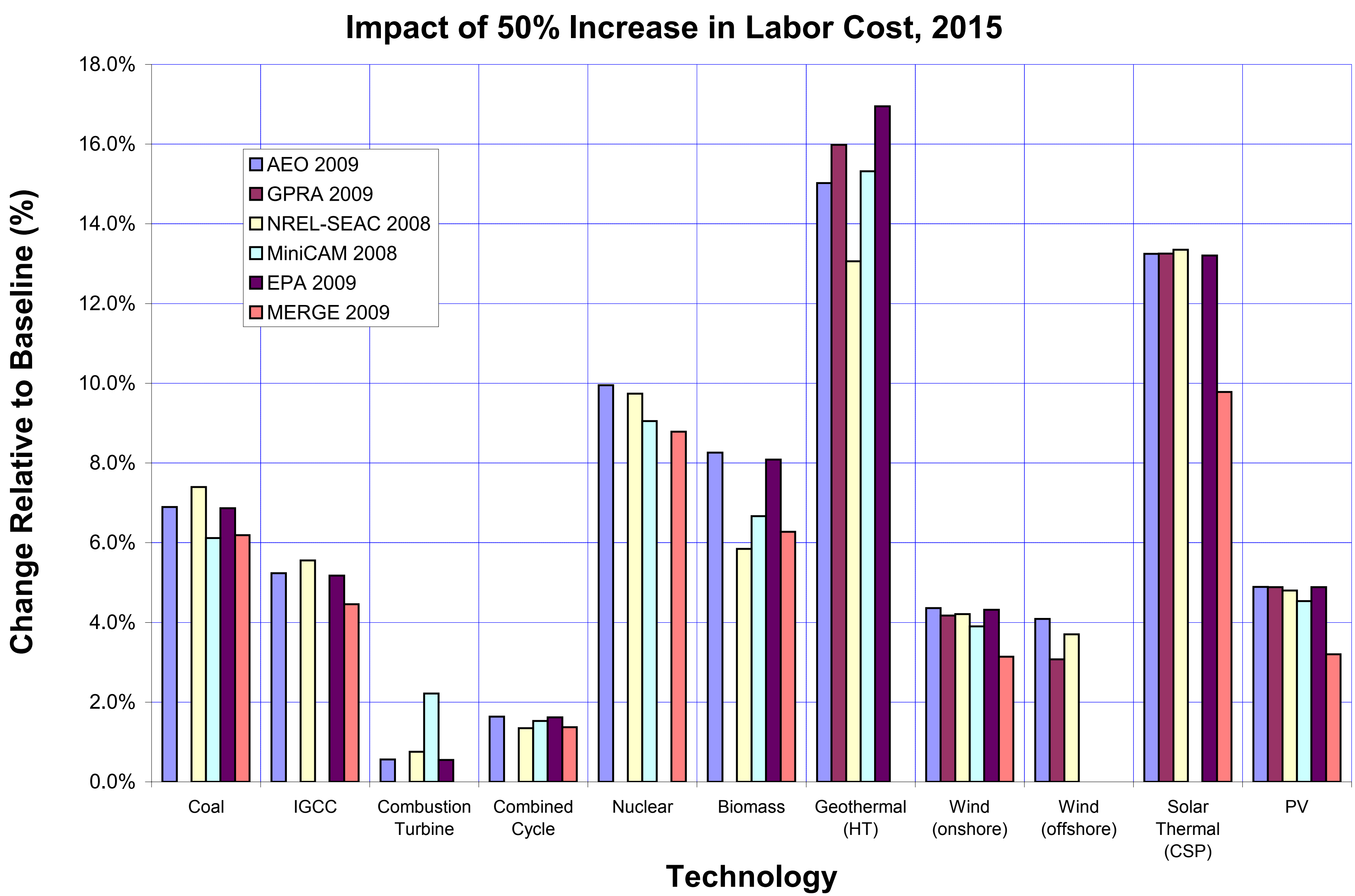


Figure 68. Impact on LCOE of labor cost, 50% change

4.6 Impact of Fuel Costs

For the LCOE analysis completed in this report, the fuel costs for geothermal, wind, and solar technologies are assumed to be zero. However, fossil, nuclear, and biomass technologies do have fuel costs, and the LCOE values are sensitive to changes in these fuel costs.

Figure 69 shows the sensitivity of LCOE costs to a 10% change in fuel costs. As indicated, natural gas technologies (combustion turbine and combined cycle) are the most sensitive, and these technologies show a 7% to 8% increase in LCOE with a 10% increase in the cost of natural gas. Nuclear technologies are the least sensitive, with LCOE increases of 1% to 2% depending on the data set. Coal (pulverized and IGCC) and biomass plants show an LCOE increase of 2% to 4% with a 10% increase in the cost of fuel.

Figure 70 shows the change in LCOE costs with a 50% change in fuel costs. Like the 10% case, the natural gas technologies are the most sensitive, and nuclear technologies are the least sensitive. Coal and biomass plants fall in between.

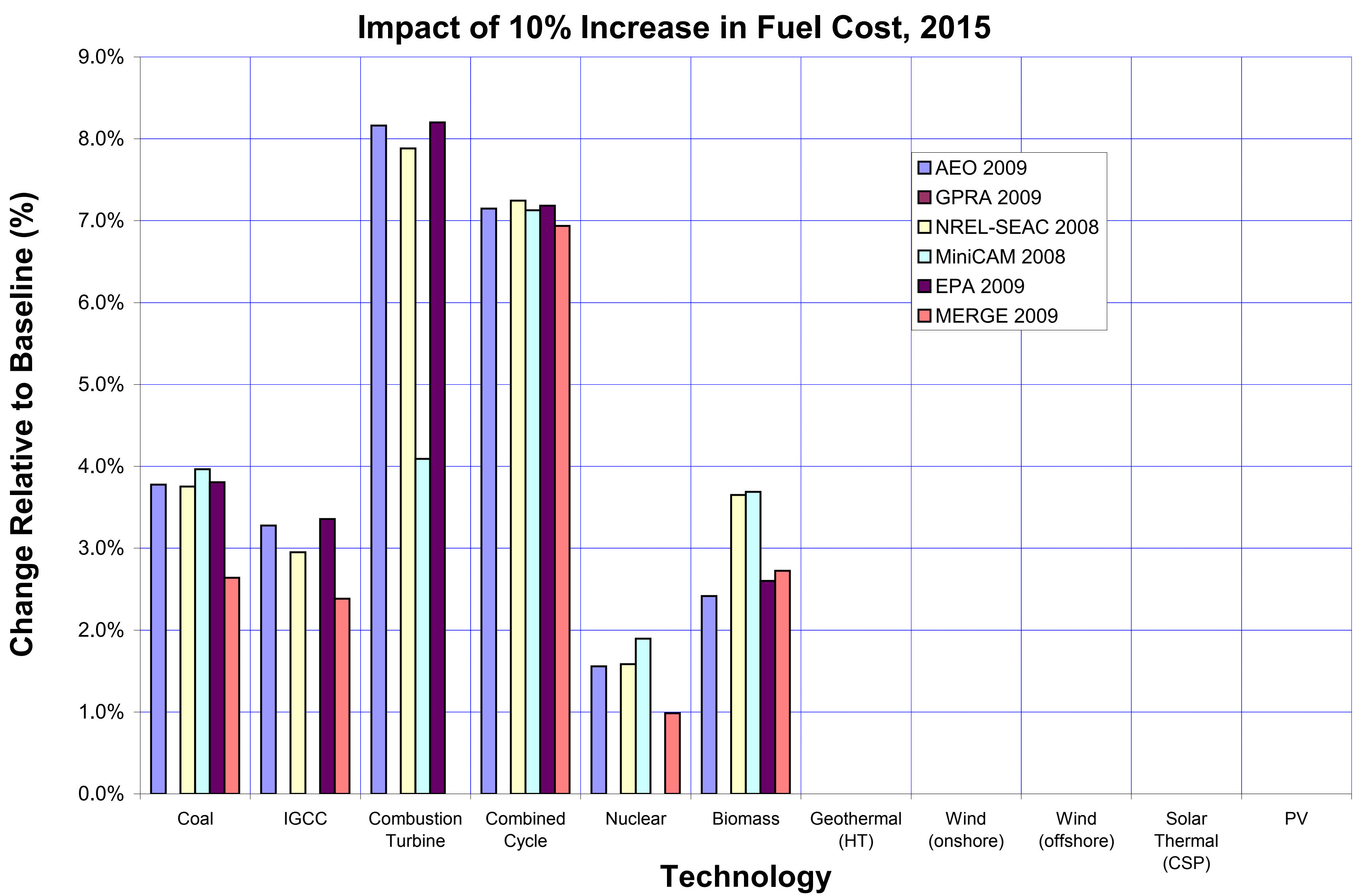


Figure 69. Impact on LCOE of fuel cost, 10% change

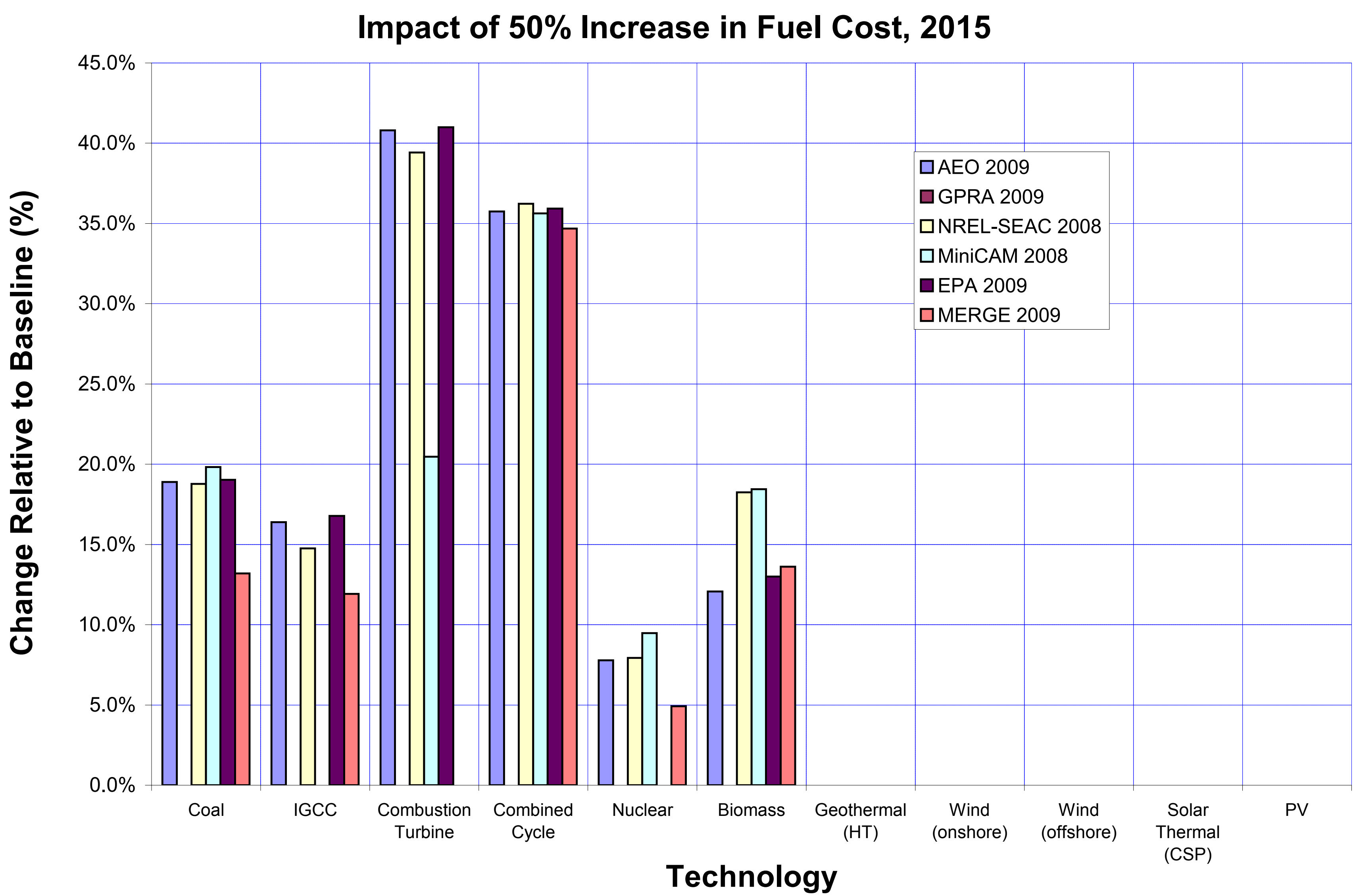


Figure 70. Impact on LCOE of fuel cost, 50% change

4.7 LCOE Conclusions

LCOE values were calculated for 11 technologies that span six data sets (see Table 19). For each technology, LCOE values were first calculated for a baseline set of conditions, followed by alternative scenario calculations designed to assess the parametric sensitivity to the following four variables:

- Increasing equipment costs: +10%, +20%, +50%
- Increasing labor costs: +10%, +20%, +50%
- Increasing fuel costs: +10%, +20%, +50%

Table 19. Matrix of LCOE Calculations

	Data Set					
Technology	**AEO 2009**	**GPRA 2009**	**NREL-SEAC 2008**	**MiniCAM 2008**	**EPA 2009**	**MERGE 2009**
Coal	X	---	X	X	X	X
IGCC	X	---	X	X	X	X
Combustion Turbine	X	---	X	X	X	---
Combined Cycle	X	---	X	X	X	X
Nuclear	X	---	X	X	X	X
Biomass	X	---	X	X	X	X
Geothermal (hydrothermal)	X	X	X	X	X	---
Wind (onshore)	X	X	X	X	X	X
Wind (offshore)	X	X	X	---	---	---
Solar Thermal	X	X	X	X	X	X
PV	X	X	X	X	X	X

Technologies not included in a particular data set are marked with "---"

Observations from the parametric sensitivity study include the following:

Equipment Costs – A 10% increase in equipment costs increases LCOE values by 1% to 6%. The larger impacts occur for wind and solar technologies where equipment costs account for a larger fraction of capital costs compared to other power generation technologies. The impact scales linearly, and a 50% increase in equipment costs increases LCOE values by approximately 5% to 30%.

Labor Costs – Geothermal technologies have a relatively high labor component (lots of site development), and as a result the impact of labor costs are greatest for geothermal technologies. In contrast, combustion turbines and combined cycle plants have relatively low on-site labor requirements, and these technologies have a weak dependence on changes in labor costs. The calculations show that a 10% increase in labor costs increases the LCOE value for geothermal technologies by slightly over 3%. The impact is less than 0.5% for combustion turbines and combined cycle plants. Like equipment costs, the impact of labor costs scales linearly, and a 50%

increase in labor costs increases LCOE values by fivefold compared to a 10% increase in labor costs.

Fuel Costs – Fuel costs for geothermal, wind, and solar technologies are assumed to be zero for the LCOE calculations in this report. However, fossil, nuclear, and biomass technologies do have fuel costs, and the LCOE values are sensitive to changes in these fuel costs. Natural gas technologies (combustion turbine and combined cycle) are the most sensitive, and these technologies show a 7% to 8% increase in LCOE with a 10% increase in the cost of natural gas. Nuclear technologies are the least sensitive, with LCOE increases of 1% to 2% depending on the data set. Coal (pulverized and IGCC) and biomass plants show an LCOE increase of 2% to 4% with a 10% increase in the cost of fuel. The impact of fuel costs scales linearly (i.e., 50% increase in fuel costs produces a fivefold impact on LCOE relative to a 10% increase in fuel costs).

5 Conclusions

This report focused on an evaluation of technical performance and cost characteristics for power generation technologies described in data sets that support energy market models. The following six data sets were examined:

- AEO 2009 (NEMS model)
- GPRA 2009 (MARKAL model)
- NREL-SEAC 2008 (ReEDS model)
- MiniCAM 2008 (MiniCAM model)
- EPA 2009 (IPM model)
- MERGE 2009 (MERGE model)

The six data sets included characteristics for 29 different types of electricity generation technologies, spanning fossil, nuclear, and renewable resources. The specific technologies covered within each data set varied, and the time horizon described differed between data sets (AEO extended to 2030, EPA to 2035, and the other four data sets to 2050). To compare and contrast characteristics between data sets, a core group of 11 technologies was selected (see Table 20).

Table 20. Eleven Core Utility Scale Power Generation Technologies

Energy Source	Utility Scale Power Generation Technology
Coal	Coal (pulverized coal plant)
	Integrated Gasification Combined Cycle (IGCC)
Natural Gas	Combustion Turbine (advanced)
	Combined Cycle (advanced)
Nuclear	Nuclear plant
Biomass	Biomass gasification plant
Geothermal	Hydrothermal
Wind	Onshore
	Offshore
Solar	Solar Thermal
	Photovoltaic

Technical performance characteristics, such as the heat rate for fossil and nuclear plants, tended to track closely, although differences were observed. The largest variation in heat rate occurred for biomass plants, which is possibly a reflection of uncertainty in how this technology will evolve as it matures.

Capacity factor was another technical performance characteristic that was examined. For fossil and nuclear plants, capacity factors were generally 80% or higher and typically varied only a few percentage points between data sets (one exception occurred for one combustion turbine that was modeled as a peaking unit with a low capacity factor). Biomass and geothermal plants also had capacity factors exceeding 80%. Capacity factors for wind and solar were lower. Wind technologies (both onshore and offshore) had capacity factors near 40% in 2010, rising to slightly below 45% in 2025 (average values across all data sets). Solar thermal technologies had large capacity factor variations, in part due to inclusion of thermal energy storage in some, but not all, data sets. The average capacity factor for solar thermal technologies without storage remained constant from 2010 to 2025 at 30%, although the average capacity factor for solar thermal technologies with storage rose from 58% in 2010 to 74% in 2025. PV capacity factors were similar between data sets, with an average value of 24% in 2010, increasing to 25% in 2025.

Overnight capital costs showed disparities for all technologies across the data sets. These disparities included absolute values as well as the rate of change in overnight capital costs over time. The variations tended to be smaller for mature technologies, such as coal and combined cycle plants, which are not heavily dependent on site conditions. Less mature technologies, such as solar thermal and PV, and those that are heavily dependent on site conditions, such as geothermal, tended to show the largest variations in overnight capital costs.

In addition to examining technical performance and cost characteristics, the levelized cost of energy (LCOE) was computed using a uniform algorithm for all data sets. These calculations highlighted the magnitude of disparities across the data sets.

Energy market models forecast market penetration of power generation technologies based on economics coupled with many other criteria (e.g., demand, resource availability, grid reliability, and policies). While only part of the decision making equation, LCOE values provide insights on how different data sets can lead to different projections – often significantly different – for the types of power generation technologies that will be built in the future.

Understanding power generation characteristics that drive energy market models is a first step in understanding different model projections for the future power plant portfolio in the United States. The disparities identified in this study suggest that work is needed to better understand how data set owners develop technical and cost characteristics, including the use of commodity price indices to adjust capital costs. Additional work is also recommended to track how data set characteristics change. The six data sets examined in this study are updated periodically, and these changes, and the subsequent impact on LCOE results, should be followed.

Appendix A. NEMS (AEO 2009 Data Set)

The AEO 2009 data set is based on the Annual Energy Outlook (AEO) prepared by the Energy Information Administration (EIA). The AEO 2009 report was initially released in March 2009, and then updated in April.[27] The April update was prepared to reflect provisions in the American Recovery and Reinvestment Act (ARRA) that were enacted in February 2009. Assumptions used for the power generation technologies in the AEO 2009 data set are available online.[28] However, not all details are available on-line, and ICF contacted EIA for additional information to augment the analysis.[29]

Power plant characteristics are summarized in Section 8 of the Assumptions to the Annual Energy Outlook 2009.[30] The assumptions in this section pertain to the Electricity Market Module, which is one component of the NEMS model. In this documentation, EIA indicates that the electricity generation plant characteristics are intended to reflect cost and performance values for typical plants under normal operating conditions. EIA indicates that the data were derived from various sources, including internal EIA resources, DOE Field Offices, National Laboratories, and discussions with industry and government personnel. EIA also consulted industry reports, including:

- World Bank Report, Study of Equipment Prices in the Power Industry, June 2008 draft.
- Lawrence Berkeley National Laboratory, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007, LBNL-275E.
- California Energy Commission, Integrated Energy Policy Report, CEC-100-2007-008-CMF, December 2007.
- Nuclear Energy Institute presentation, "Assessing the Economics of New Nuclear Power", Center for Strategic and International Studies, July 31, 2008.
    - The AEO 2009 data set includes cost and performance characteristics for 20 electricity generation technologies that could be built over a modeling horizon that extends to 2030.

The AEO 2009 data set includes cost and performance characteristics for 20 electricity generation technologies that could be built over a modeling horizon that extends to 2030. These characteristics are summarized in Table 21.

[27] Annual Energy Outlook 2009, DOE/EIA-0383, March 2009, http://www.eia.doe.gov/oiaf/archive/aeo09/, accessed September 2009.
[28] Assumptions to the Annual Energy Outlook 2009, Table 8.2, p89, http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html, accessed September 2009.
[29] Data were provided during the course of several e-mail exchanges during the months of September and October 2009. Laura Martin was the primary contact at EIA.
[30] Assumptions to the Annual Energy Outlook 2009, Section 8, Electricity Market Module, http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html, accessed September 2009.

Table 21. Cost and Performance Characteristics in AEO 2009 for 20 Technologies[31]

Technology	Size (MW)	Online Year	Lead Time (yrs)	Heat Rate (Btu/kWh) 2008	Heat Rate (Btu/kWh) nth of kind	Capacity Factor[32]	Plant Lifetime (yrs)	Base Overnight Capital Cost (2007$/kW)	O&M (2007$) Variable ($/MWh)	O&M (2007$) Fixed ($/kW)
Coal (pulverized)	600	2012	4	9,200	8,740	85%	---	1,923	4.59	27.53
Integrated Gasification Combined Cycle (IGCC)	550	2012	4	8,765	7,450	85%	---	2,223	2.92	38.67
IGCC w/ Carbon Capture and Sequestration (CCS)	380	2016	4	10,781	8,307	85%	---	3,172	4.44	46.12
Combustion Turbine (conventional)	160	2010	2	10,810	10,450	92%	---	638	3.57	12.11
Combustion Turbine (advanced)	230	2010	2	9,289	8,550	92%	---	604	3.17	10.53
Combined Cycle (conventional)	250	2011	3	7,196	6,800	87%	---	917	2.07	12.48
Combined Cycle (advanced)	400	2011	3	6,752	6,333	87%	---	877	2	11.7
Combined Cycle with CCS	400	2016	3	8,613	7,493	87%	---	1,683	2.94	19.9
Fuel Cells	10	2011	3	7,930	6,960	87%	---	4,640	47.92	5.65
Nuclear	1,350	2016	6	10,434	10,434	90%	60	2,873	0.49	90.02
Distributed Gen (base)	2	2011	3	9,050	8,900	50%	---	1,305	7.12	16.03
Distributed Gen (peak)	1	2010	2	10,069	9,880	5%	---	1,566	7.12	16.03
Biomass	80	2012	4	9,646	7,765	83%	---	3,339	6.71	64.45
Municipal Solid Waste (MSW) & Landfill Gas (LFG)	30	2010	3	13,648	13,648	---	---	2,377	0.01	114.25
Geothermal	50	2010	4	34,633	30,301	90%	---	1,630	0	164.64
Hydro	500	2012	4	---	---	57%	---	2,038	2.43	13.63
Wind (onshore)	50	2009	3	---	---	44%	---	1,797	0	30.3
Wind (offshore)	100	2012	4	---	---	40%	---	3,416	0	89.48
Solar Thermal	100	2012	3	---	---	31%	---	4,693	0	56.78
PV	5	2011	2	---	---	22%	---	5,750	0	11.68

[31] Highlighted technologies (11 total) correspond to those technologies that represent the focus group for this report.
[32] Capacity factors are endogenous in the NEMS model, and can change over time. The values shown correspond to maximum availability factors in 2010, or the first year technologies come online. .

Power plant characteristics for the 11 focus technologies are discussed in the remainder of this appendix, which is organized as follows:

- Technical Performance Characteristics
  - Plant Size
  - Online Year & Lead Time
  - Heat Rate
  - Capacity Factor
  - Plant Lifetime
- Cost Characteristics
  - Overnight Capital Costs
  - Learning
  - Commodity Cost Adjustments – based on Metals and Metal Products PPI
  - Operation and Maintenance (O&M) Costs

5.1.1 Technical Performance Characteristics

Plant Size

Each technology in the AEO 2009 data set is represented by a single typical plant size. Plant capacities for 11 technologies are compared in Figure 71. These 11 technologies represent a cross section of fossil, nuclear, and renewable technologies, and include those technologies that are expected to make a significant contribution in meeting the demand for future power. In the case of combustion turbine and combined cycle technologies, Figure 71 shows power plant size for advanced, rather than conventional, technologies.

As indicated in Figure 71, there is a large size range between technologies. Nuclear is the largest at 1,350 MW, and PV is the smallest at 5 MW. In the AEO 2009 data set, the maximum plant capacities for all technologies, including PV, remain unchanged over the modeling period.

Online Year & Lead Time

The online year represents the first year that a new unit could be completed based on an order date of 2008. The lead time represents the lag between the order date for a new plant and the date when the new plant is expected to go into service.

The term "vintage year" is used elsewhere in this report but has a different meaning than "online year." Vintage year is used to describe power plant characteristics for a particular time period. For example, in data sets such as EPA 2009, a characteristic such as the heat rate for combustion turbines may be constant for a vintage year time period – say 2015 to 2020. If combustion turbine heat rates are expected to improve after 2020, a new vintage year time period – say 2021 through the end of the modeling cycle – will be defined with an improved heat rate for combustion turbines. The term vintage year is not used in conjunction with the AEO 2009 data set.

For most technologies in the AEO 2009 data set, the online year coincides with the lead time added to the year 2008. However, there are exceptions. For geothermal and onshore wind technologies, the online year was advanced due to accelerated market activity occurring in anticipation of the expiration of Production Tax Credits33. The advanced online year for geothermal and onshore wind power plants is illustrated in Figure 72 (blue diamond below top of column). Figure 72 also signifies technologies that were not commercially available in 2008 (blue diamond above column). For example, nuclear technology (based on advanced technology) is not expected to be ready for commercial orders until 2010 (six year lead time results in online year of 2016).

[33] PTCs expected to expire in 2009 for wind and 2010 for geothermal and LFG.

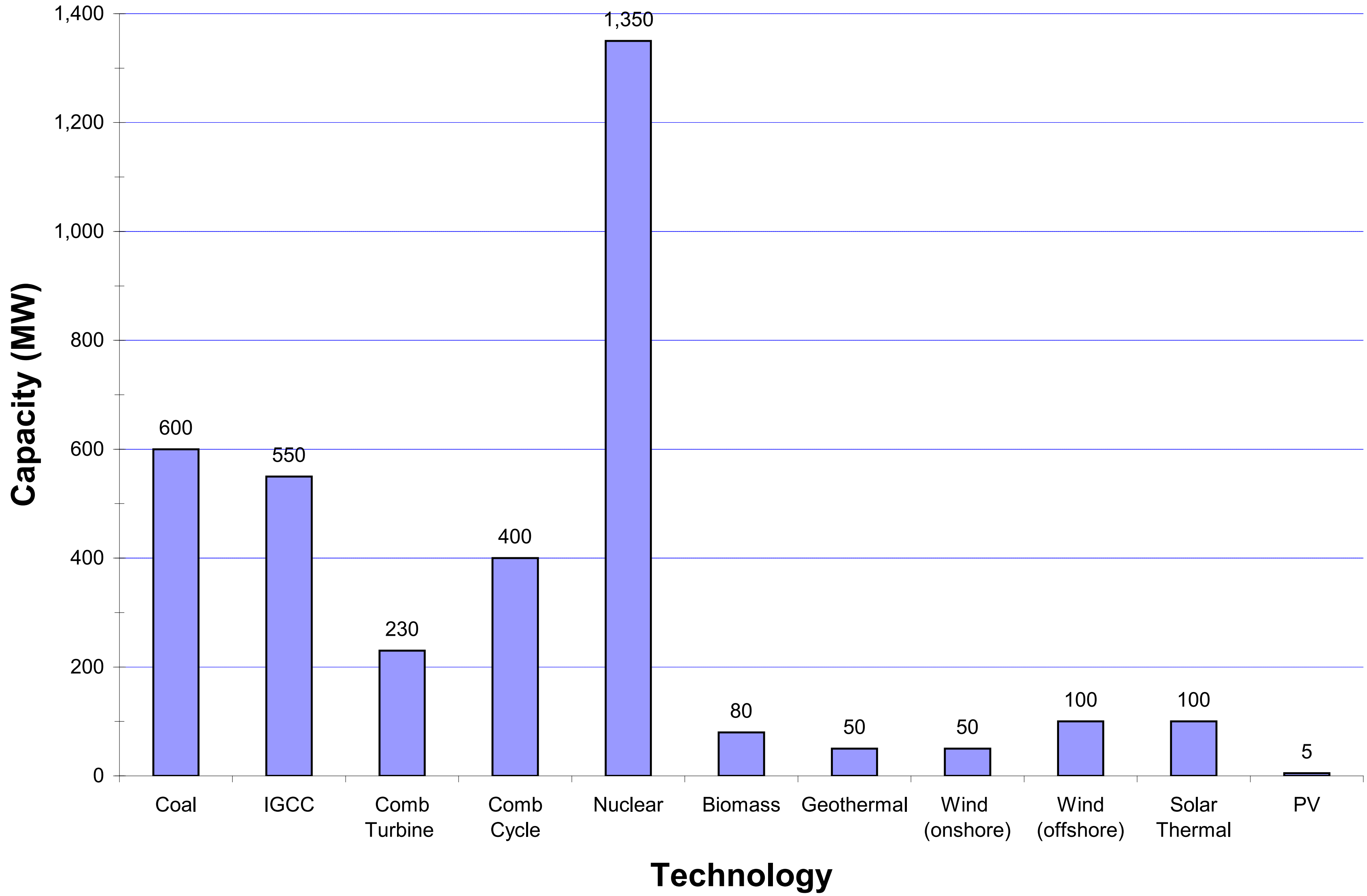


Figure 71. AEO 2009, plant capacities in online year

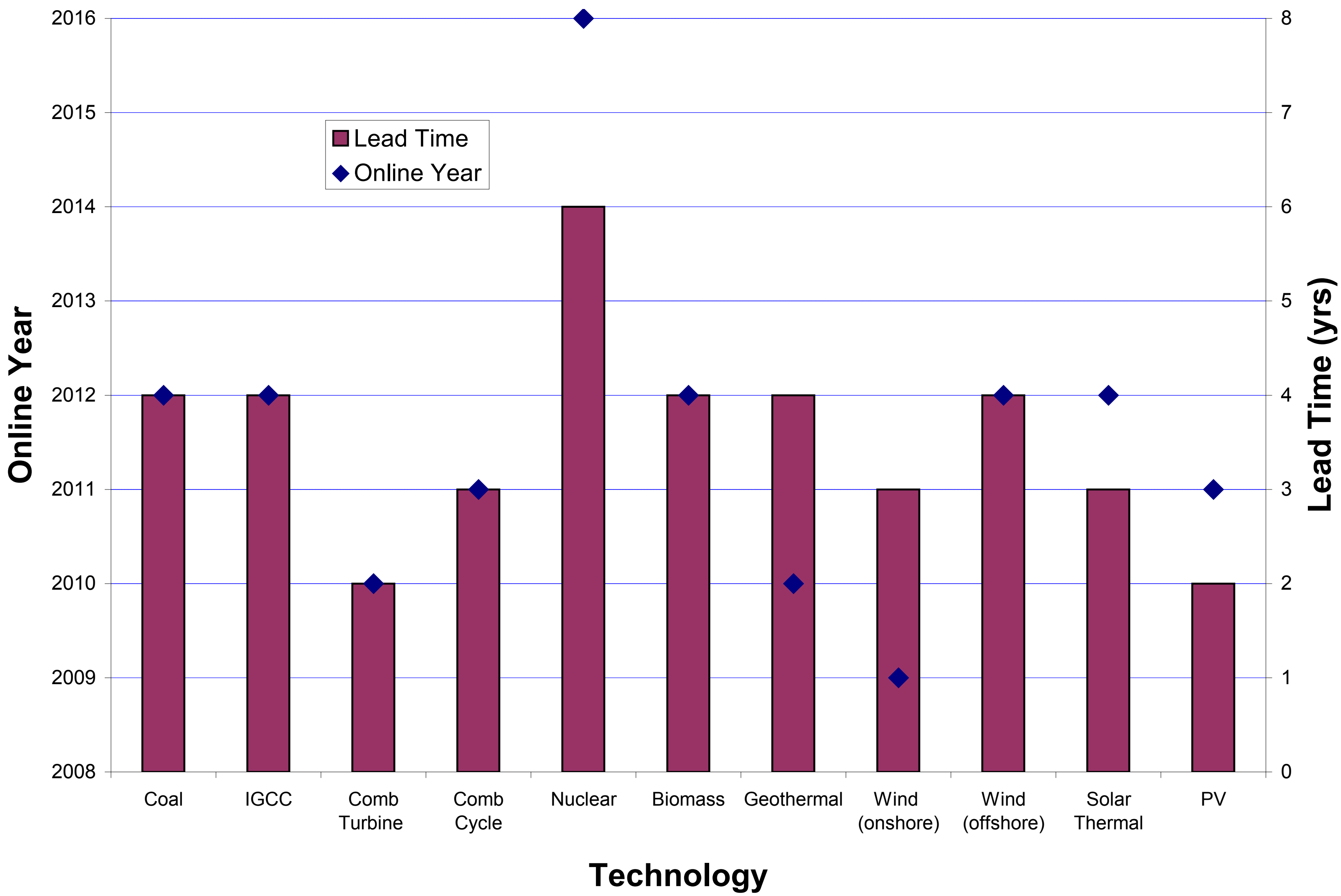


Figure 72. AEO 2009, online year and lead times

Heat Rate

The AEO 2009 data set contains two heat rates. The first heat rate represents existing equipment available in 2008. The "nth of a kind" heat rate represents a reduced heat rate resulting from technology improvements. The first heat rate is the highest (least efficient) value and corresponds to the heat rate for technology that is installed in the first online year (online years and corresponding heat rates are shown in Table 21). The "nth of a kind" heat rate is the lowest (most efficient) and corresponds to the heat rate in 2025. Heat rates decline linearly between the on-line year and 2025, and remain unchanged through 2030 (end of the NEMS modeling horizon).[34]

A comparison of the highest and lowest heat rates for 11 technologies in the AEO 2009 data set is shown in Figure 73. Heat rates are not applied to wind and solar technologies.

Capacity Factor

Table 21 lists the capacity factors for the technologies included in the AEO 2009 data set, and Figure 74 shows these factors for 11 focus technologies. In the AEO 2009 data set, capacity factors are an output parameter, not an input characteristic, for the NEMS model.

EIA provided maximum capacity factors for all technologies, and the data shown correspond to maximum capacity factors. For wind, EIA provided minimum, maximum and average capacity factors, but for all other technologies, only maximum capacity factors were provided.

In general, the capacity factors remain relatively constant over the modeling horizon (2009 through 2030), but fluctuations do occur. As indicated in Figure 74, the capacity factors are relatively high for fossil, nuclear, and geothermal technologies (85% to 92%). Wind and solar technologies have significantly lower capacity factors, which are in the range of 22% to 42%.

Plant Lifetime

The modeling approach in NEMS is to allow plants to operate as long as they are economic compared to the alternatives. When a plant is no longer economic, it is retired. As a result of this approach, the AEO 2009 data set does not contain pre-determined plant lifetimes. There are exceptions, however. For example, nuclear plants do have a pre-determined lifetime of 60 years (40 year initial license plus one 20 year license renewal).

[34] EIA indicated that heat rates for biomass and geothermal are handled differently. A detailed explanation of the differences was not provided (e-mail exchange between ICF and EIA, November 2, 2009).

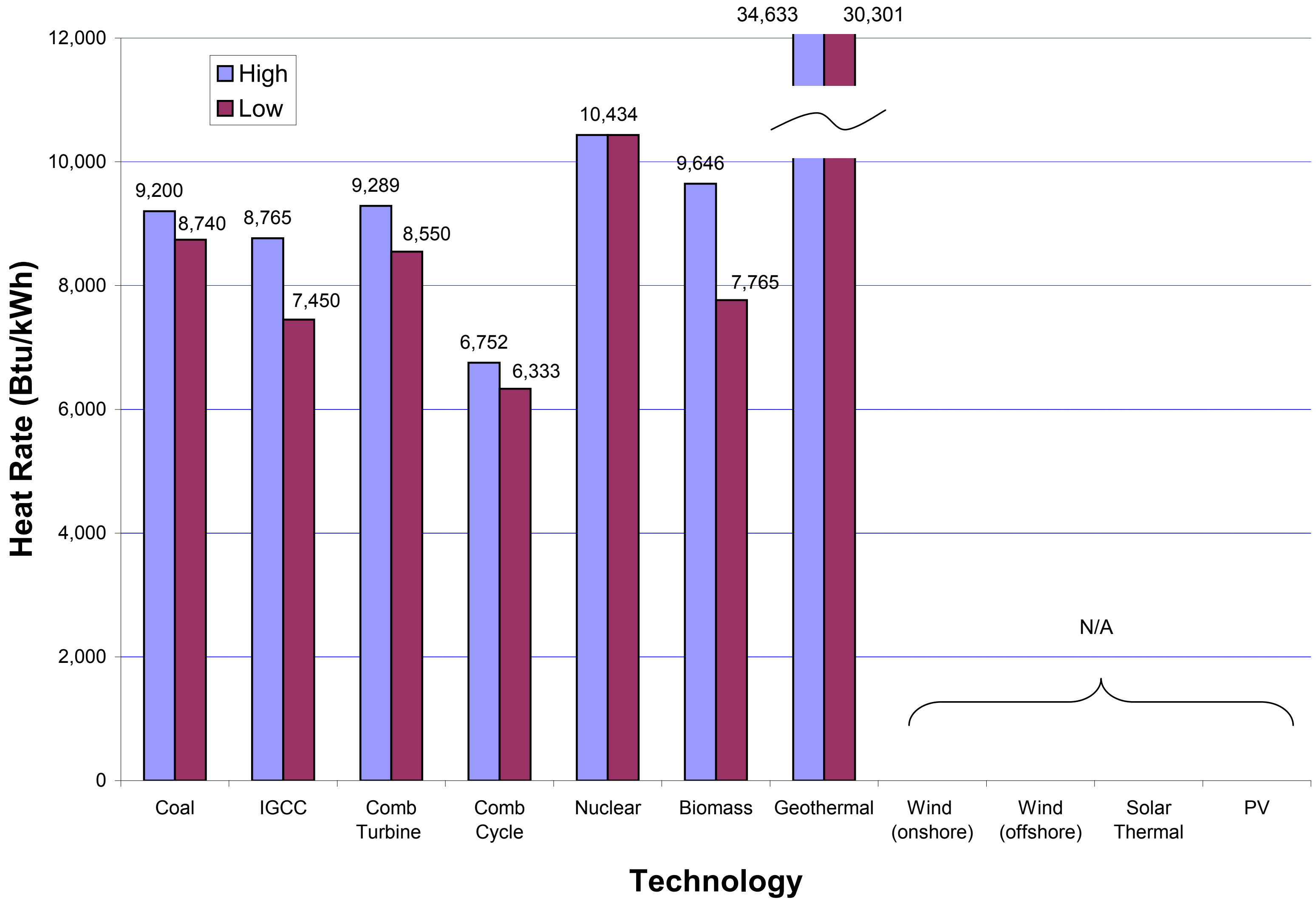


Figure 73. AEO 2009, high and low heat rates

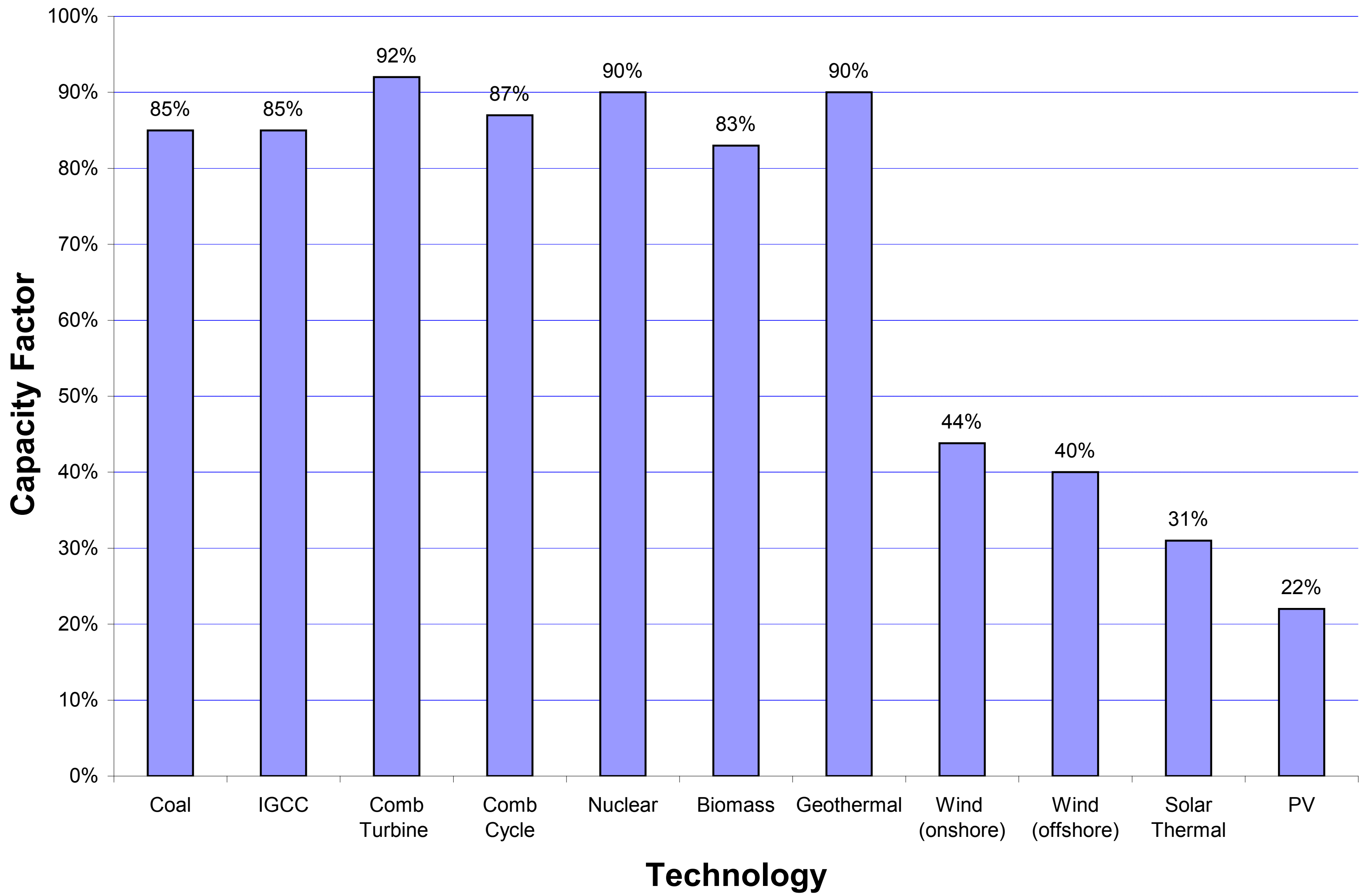


Figure 74. AEO 2009, capacity factors

5.1.2 Cost Characteristics

Overnight Capital Costs

In the EIA AEO 2009 data set, the base overnight costs shown in Table 21 are adjusted by two parameters to develop a starting year (2009) overnight cost. These two adjustment factors are project contingency and technology optimism (both factors are shown in Table 22).

Table 22. AEO 2009, Overnight Capital Costs in 2009 (reported in 2007$)

Technology	Base Overnight Cost (2007$/kW)	Adjustment Factors: Project Contingency	Adjustment Factors: Technology Optimism	Total Overnight Capital Cost (2007$/kW)
Coal	1,923	1.070	1.000	2,058
IGCC	2,223	1.070	1.000	2,378
IGCC w/ CCS	3,172	1.070	1.030	3,496
Combustion Turbine (conv.)	638	1.050	1.000	670
Combustion Turbine (adv)	604	1.050	1.000	634
Combined Cycle (conv.)	917	1.050	1.000	963
Combined Cycle (adv.)	877	1.080	1.000	948
Combined Cycle with CCS	1,683	1.080	1.040	1,890
Fuel Cells	4,640	1.050	1.100	5,359
Nuclear	2,873	1.100	1.050	3,318
DG (base)	1,305	1.050	1.000	1,370
DG (peak)	1,566	1.050	1.000	1,644
Biomass	3,339	1.070	1.054	3,766
MSW, LFG	2,377	1.070	1.000	2,543
Geothermal	1,630	1.050	1.000	1,711
Hydro	2,038	1.100	1.000	2,242
Wind (onshore)	1,797	1.070	1.000	1,923
Wind (offshore)	3,416	1.100	1.025	3,851
Solar Thermal	4,693	1.070	1.000	5,021
PV	5,750	1.050	1.000	6,038

The project contingency factor[35] accounts for unforeseeable elements that may increase costs. EIA references the American Association of Cost Engineers as a source for developing contingency factors. The contingency factors range between 1.05 and 1.10, and remain constant over the NEMS modeling horizon (2009 through 2030).

[35] The project contingency factor is only used in the AEO data set. The ReEDS data set, discussed later in this report, introduces construction cost multipliers, which are based on similar principles to the AEO project contingency factors. However, the AEO project contingency factors should not be confused with the ReEDS construction cost multipliers.

EIA uses the technology optimism factor to account for a tendency to underestimate costs for emerging technologies or new designs that are unproven. For mature or proven technologies this factor is one, and for emerging or unproven technologies, the factor is greater than one. As experience is gained, the technology optimism factor is gradually reduced to one.

The starting points for total overnight capital costs used in the AEO 2009 data set are shown in Figure 75 for the 11 focus technologies. As indicated in this figure, costs range from $652/kW for a combustion turbine (advanced) to approximately $6,000/kW for PV.

Learning

Over the course of the NEMS modeling horizon (2009 through 2030), total overnight capital costs are reduced based on learning effects. Learning is based on installed capacity, and in the NEMS model, learning is divided into three periods depending on technology maturity level. The periods correspond to revolutionary (Period 1), evolutionary (Period 2), and mature (Period 3), with the learning rate declining from Period 1 through Period 3. In NEMS, learning is described for major components to account for cross-over effects that impact power generation systems that use the same major components. For example, the turbine generator for a combustion turbine, combined cycle plant, and an IGCC plant is basically the same, and the construction of any of these three plants will contribute to learning effects (i.e., cost reductions) for the combustion turbine. A summary of the learning parameters in the AEO 2009 data set is shown in Table 23.

Table 23. AEO 2009, Learning Parameters

	Learning Rate by Period			Capacity Doublings Required to Advance		Minimum Learning by 2025
Technology Component	**1**	**2**	**3**	**1-2**	**2-3**	
Pulverized Coal	---	---	1%	---	---	5%
Combustion Turbine – conv.	---	---	1%	---	---	5%
Combustion Turbine – adv.	---	10%	1%	---	5	10%
Heat Recovery Steam Generator	---	---	1%	---	---	5%
Gasifier	---	10%	1%	---	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant – IGCC	---	---	1%	---	---	5%
Balance of Plant – Turbine	---	---	1%	---	---	5%
Balance of Plant – Comb. Cycle	---	---	1%	---	---	5%
Fuel Cell	20%	10%	1%	3	5	20%
Nuclear (adv)	5%	3%	1%	3	5	10%
Fuel Prep – Biomass IGCC	20%	10%	1%	3	5	20%
Dist Gen – Base	---	5%	1%	---	5	10%
Dist Gen – Peak	---	5%	1%	---	5	10%
Geothermal	---	8%	1%	---	5	10%
Municipal Solid Waste	---	---	1%	---	---	5%
Hydropower	---	---	1%	---	---	5%
Wind (onshore)	---	---	1%	---	---	1%
Wind (offshore)	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

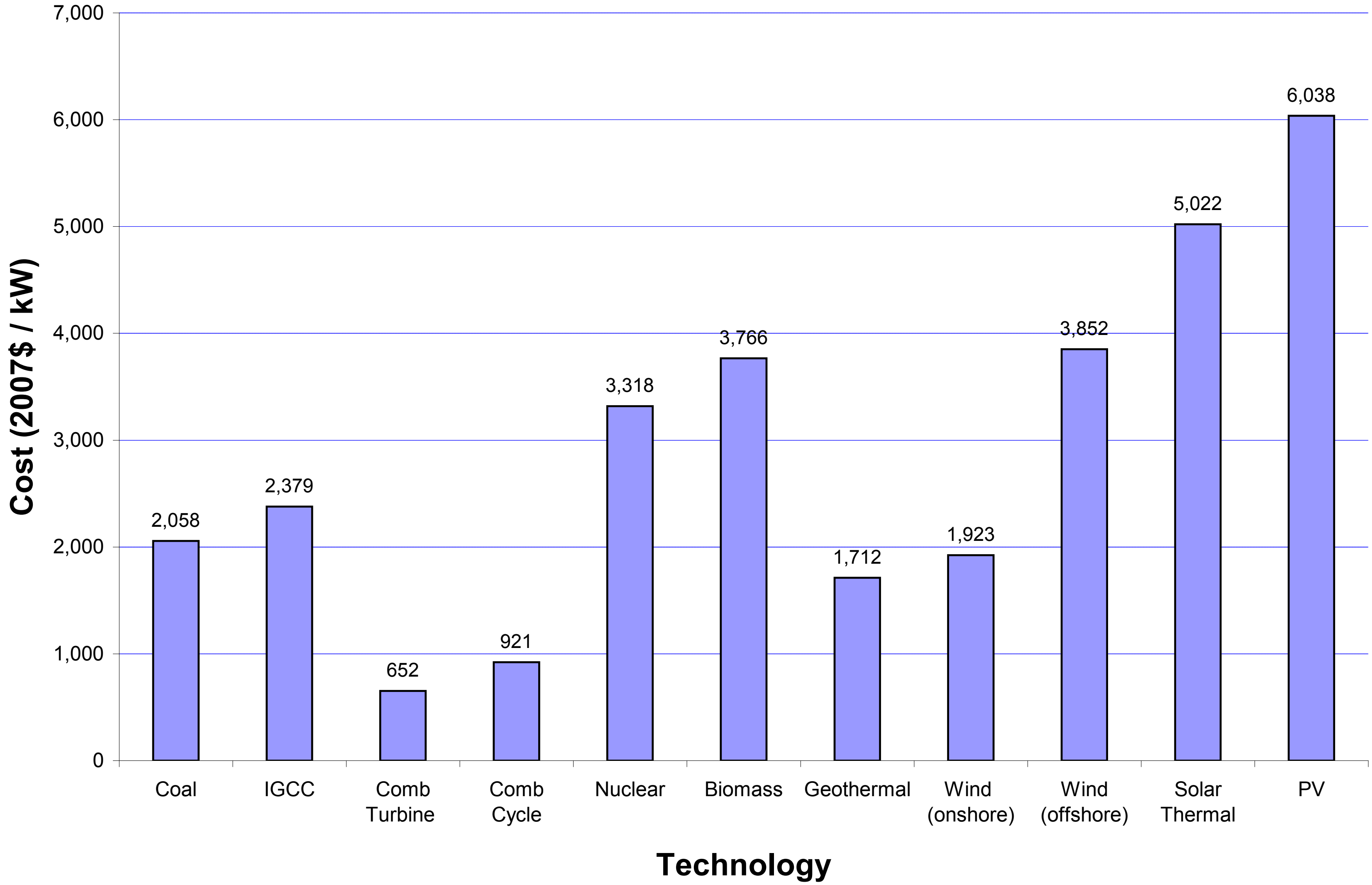


Figure 75. AEO 2009, overnight capital costs

In Table 23, learning rates for Period 1 are supplied for those technologies that are grouped in this category in 2009. For example, offshore wind is regarded as being in a revolutionary development phase (Period 1) in 2009, and pulverized coal is regarded as a mature technology (Period 3) in 2009. In the NEMS model, technologies are advanced to the next learning period based on cumulative installed capacities. In all cases, the AEO 2009 data used three doublings to advance technologies from Period 1 to Period 2, and five doublings to move technologies from Period 2 to Period 3.

As noted in Table 23, a minimum learning by 2025 is set for all technologies, regardless of capacity additions. This minimum learning is intended to account for international development (i.e., technologies installed outside of the United States) or increased research and development.[36] It is interesting to note that all technologies, with the exception of onshore wind, have a minimum learning of at least 5% by 2025. For onshore wind, the minimum learning is set at 1%. It is unclear why the AEO 2009 data set uses a minimum learning of only 1% for onshore wind. Perhaps major breakthroughs from learning by R&D are not anticipated, or perhaps significant advancements in cost reductions are not viewed as likely.

From a numerical perspective, learning factors are expressed as a multiplier that is applied to the overnight capital cost for a particular technology in the staring year for the modeling period. Learning factors for all technologies start at one in 2009, and then decline over time. The learning factors are relatively steep for technologies in a revolutionary development phase (Period 1), and relatively shallow for mature technologies (Period 3). In the AEO 2009 data set, the lowest learning occurs for onshore wind, and the highest learning occurs for solar thermal power plants. These two technologies are shown in Figure 76. In Figure 77, the learning functions for the 11 focus technologies are shown for the time period of 2009 and 2030. The learning factors in both figures represent total learning effects, and include all cross-over learning that occurs at the component level (based on cumulative installed capacity as forecast by NEMS).

Commodity Cost Adjustments – based on Metals and Metal Products PPI

In addition to learning factors, the AEO 2009 data set also includes a commodity adjustment based on the producer price index (PPI) for metals and metal products. In the AEO 2009 data set, the same commodity adjustment factor is used for all 20 technologies over the modeling horizon. EIA recognizes that different technologies have different commodity price dependencies. However, the PPI adjustment has just recently been added, and it is an initial attempt to correct for fluctuating commodity prices. The PPI adjustment curve is shown in Figure 78.

In summary, overnight capital costs in the AEO 2009 data set change over time based on four factors: 1) project contingency, 2) technology optimism, 3) learning, and 4) metal and metal products PPI. Figure 79 shows the overnight capital costs for the 11 focus technologies in the AEO data set.

[36] EIA, Assumptions to AEO 2009, p 91.

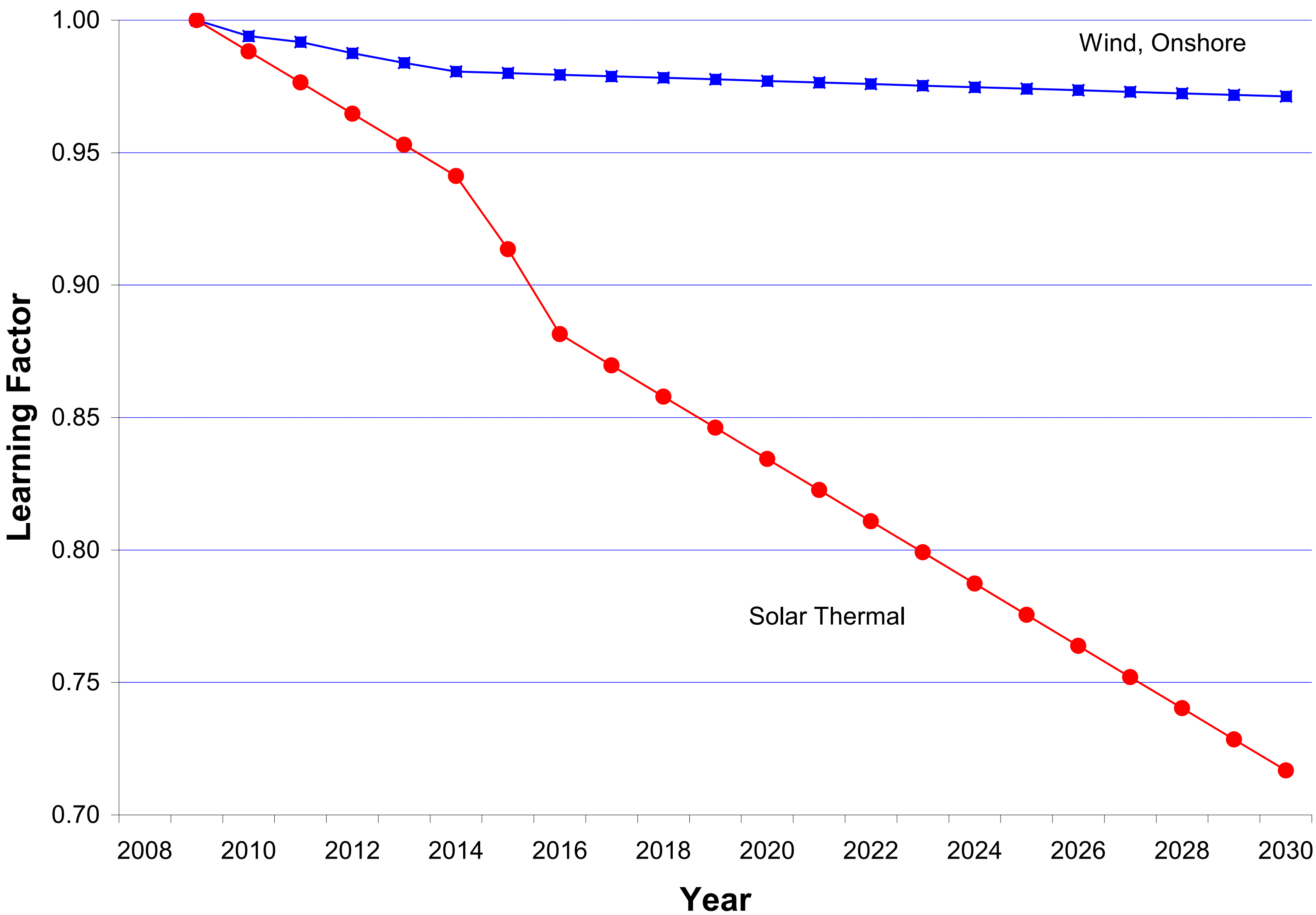


Figure 76. AEO 2009, highest and lowest learning function values

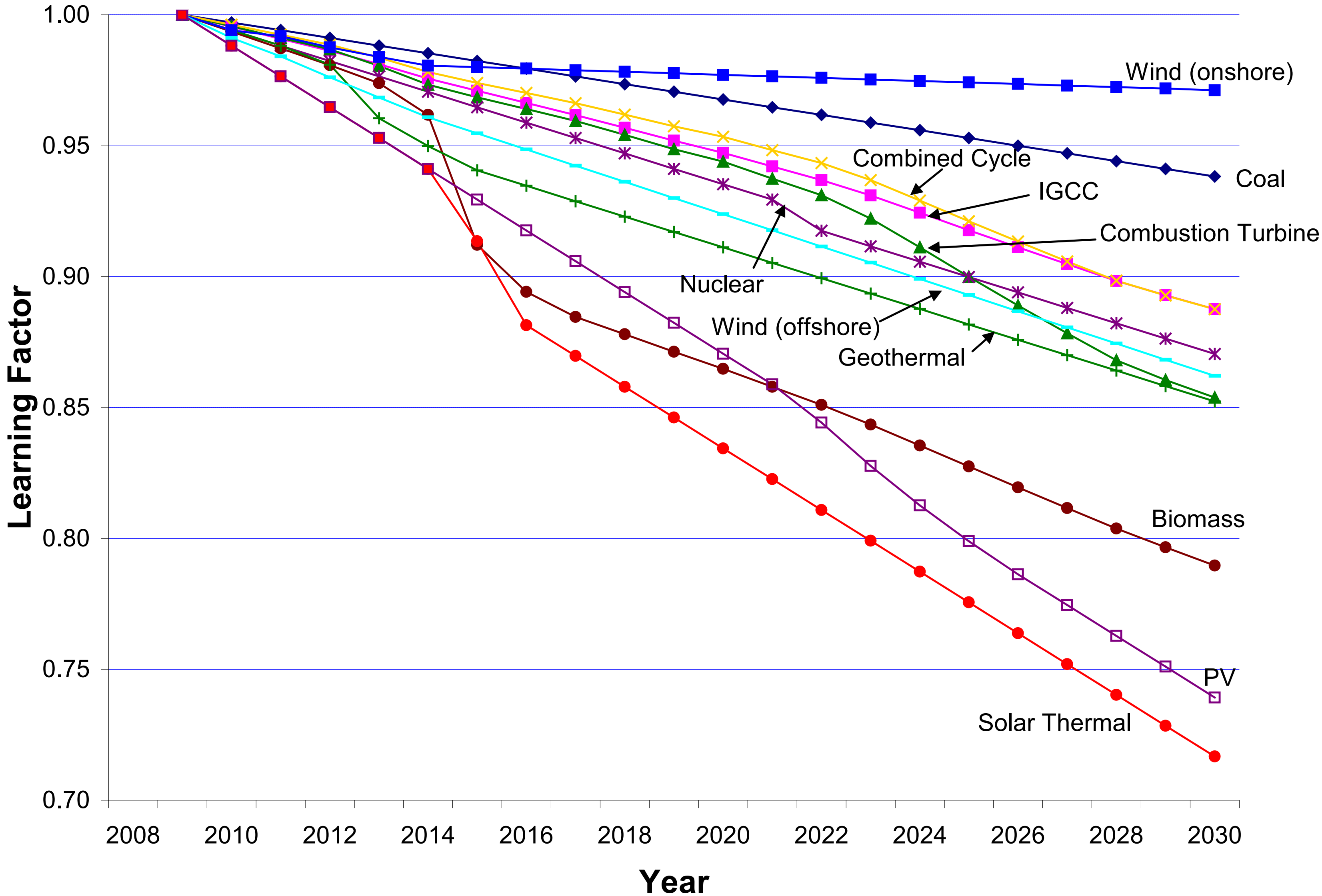


Figure 77. AEO 2009, learning function values for the 11 focus technologies

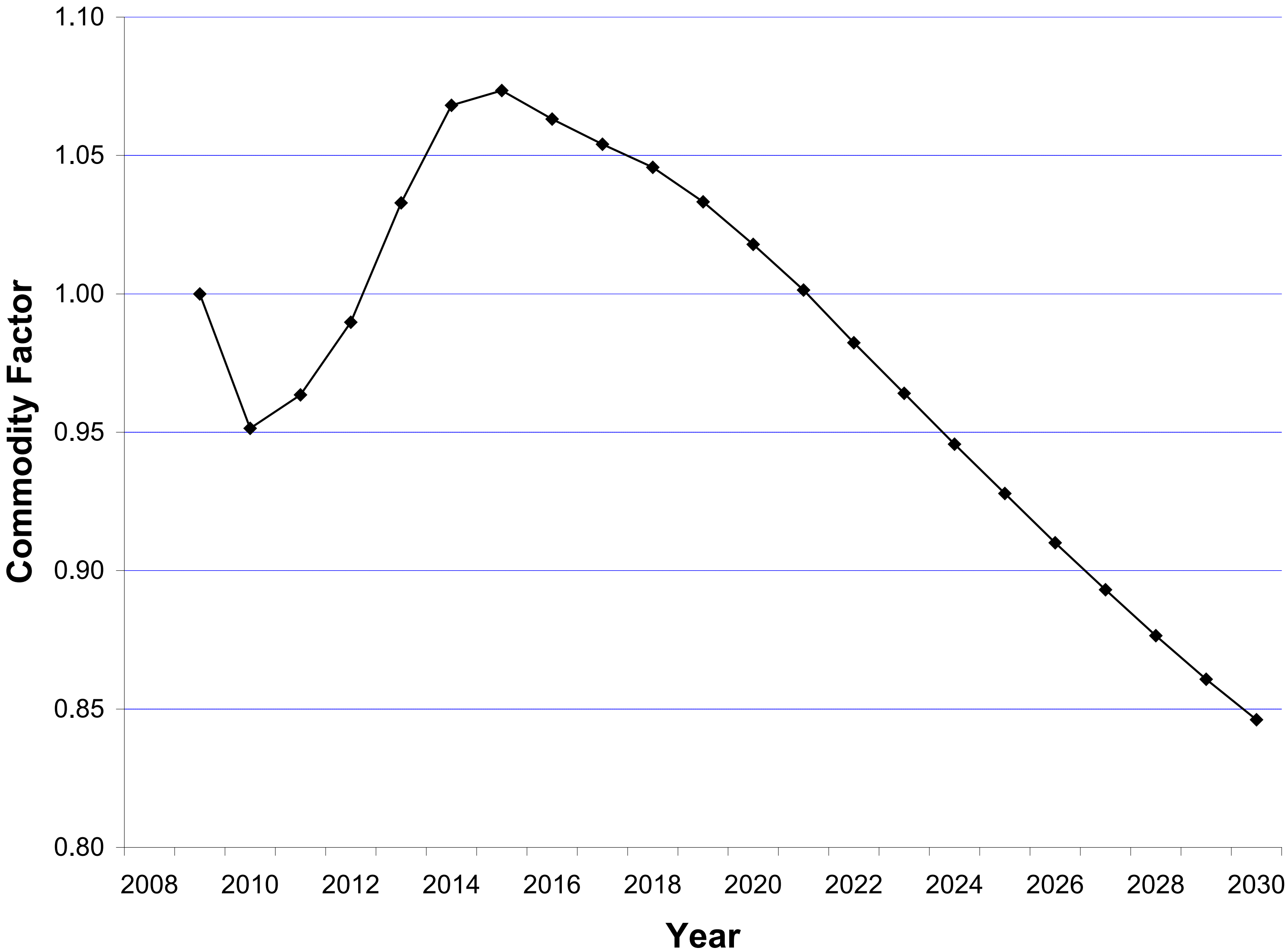


Figure 78. AEO 2009, commodity price adjustment factor for all technologies

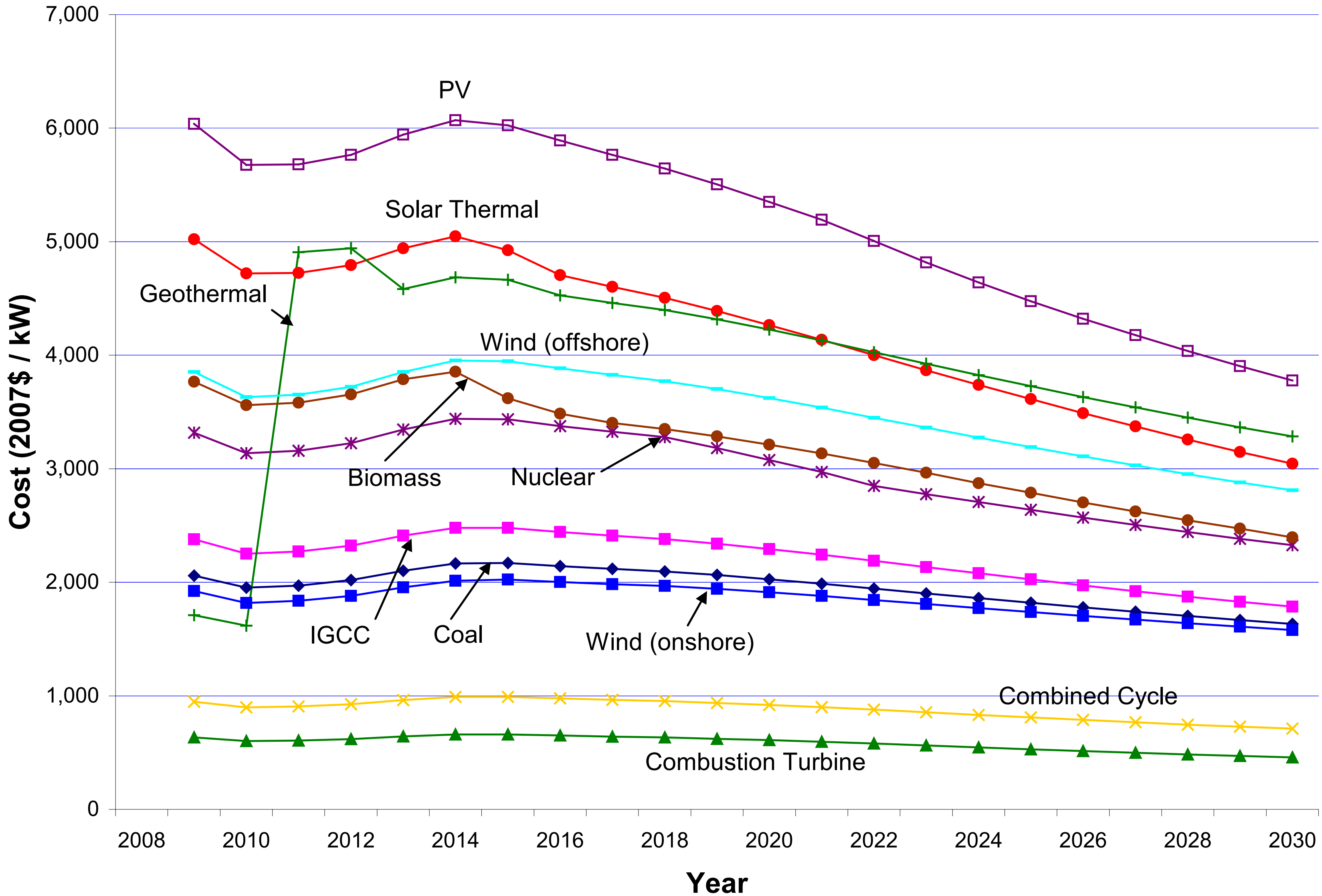


Figure 79. AEO 2009, overnight capital costs for the 11 focus technologies

O&M Costs

Table 24 shows the variable and fixed operation and maintenance (O&M) costs used in the AEO 2009 data set.

Table 24. AEO 2009, O&M Costs

	O&M	
Technology	Variable (2007$/MWh)	Fixed (2007$/kW/yr)
Coal	4.59	27.53
IGCC	2.92	38.67
IGCC w/ CCS	4.44	46.12
Combined Cycle (conv.)	2.07	12.48
Combined Cycle (adv.)	2.00	11.70
Combined Cycle with CCS	2.94	19.90
Combustion Turbine (conv.)	3.57	12.11
Combustion Turbine (adv.)	3.17	10.53
Fuel Cells	47.92	5.65
Nuclear	0.49	90.02
DG (base)	7.12	16.03
DG (peak)	7.12	16.03
Biomass	6.71	64.45
MSW, LFG	0.01	114.25
Geothermal	0	164.64
Hydro	2.43	13.63
Wind (onshore)	0	30.30
Wind (offshore)	0	89.48
Solar Thermal	0	56.78
PV	0	11.68

In some data sets, such as MERGE (which is described in a separate section of this report), variable and fixed O&M costs are rolled into a single “all-inclusive” category, and a single O&M cost is reported. However, the AEO 2009 data set does make a clear distinction between variable and fixed O&M costs, and these distinct costs are shown in Table 24. These values, which are expressed in 2007 dollars, do not change over the NEMS modeling horizon (i.e., O&M costs remain constant through 2030).

The O&M values for the 11 focus technologies are shown in Figure 80**.** Note that for geothermal, wind, and solar technologies, the variable O&M costs are zero. In the AEO 2009 data set, the O&M costs for these technologies are assumed to be dominated by fixed costs with a negligible contribution from variable factors.

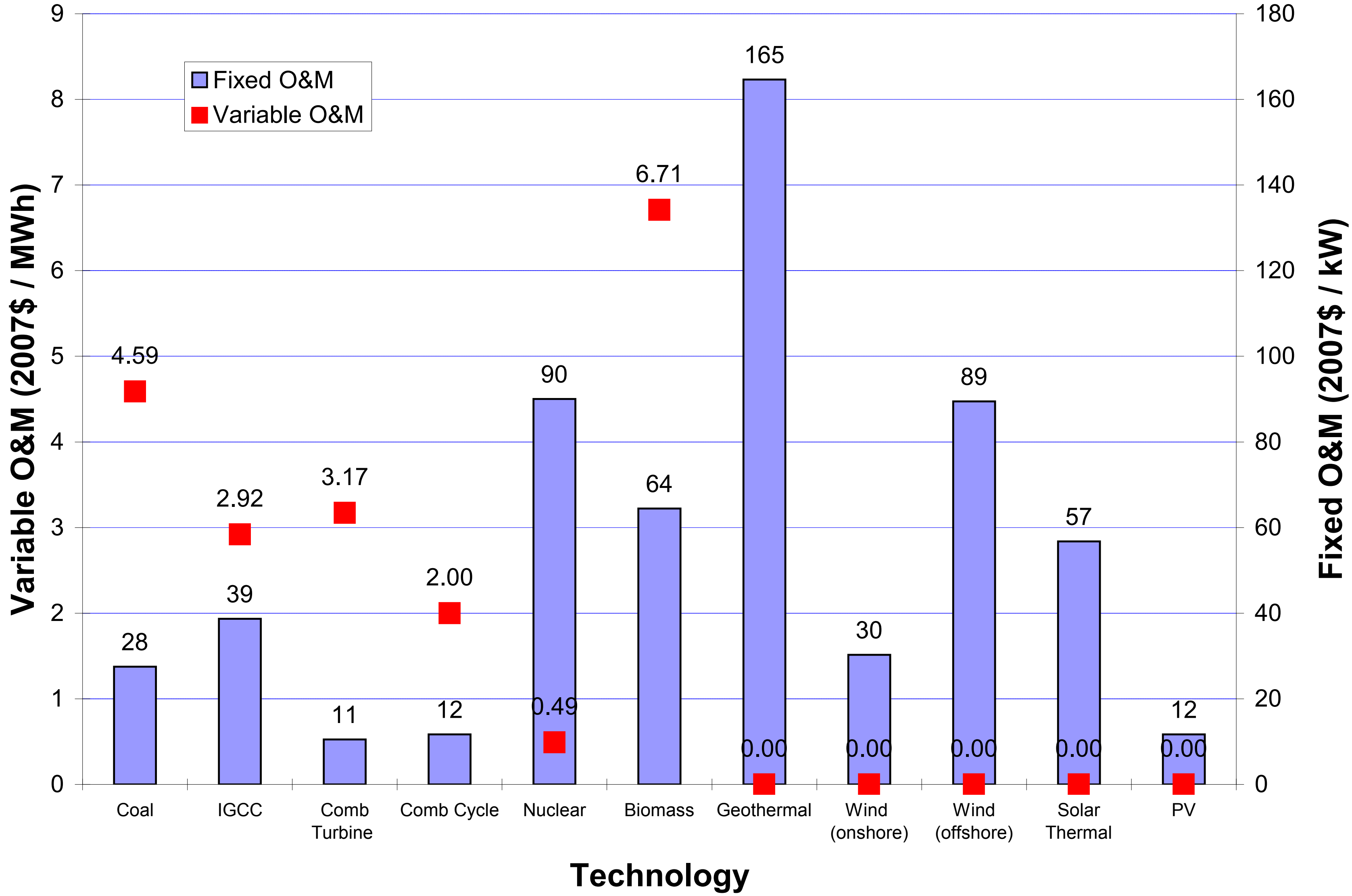


Figure 80. AEO 2009, variable O&M

Appendix B. MARKAL (GPRA 2009 Data Set)

The Government Performance and Results Act (GPRA) of 1993 requires the U.S. Department of Energy (DOE) and other Federal agencies to report annual benefits. Within DOE, the responsibilities for developing power plant characteristics for the GPRA analysis are divided between multiple offices, including:

- Renewable Power – Office of Energy Efficiency and Renewable Energy (EERE)
- Fossil Plants – Office of Fossil Energy
- Nuclear Power – Office of Nuclear Energy

In compliance with GPRA, EERE prepares an integrated benefits analysis to evaluate the effectiveness of its R&D programs (programs listed in Table 25). The GPRA analysis includes three primary cases:

- **No Funding** (Baseline Case) – No DOE R&D funding
- **Program Funding** – New R&D funding for each program
- **Portfolio Funding** -- R&D "portfolio" where each program competes for pool of funding

Table 25. DOE EERE R&D Programs[37]

DOE EERE R&D Programs
Biomass
Buildings
Federal Energy Management
Geothermal
Hydrogen & Fuel Cells
Industry
Solar
Vehicles
Weatherization & Intergovernmental
Wind & Hydropower

Within the Program Funding case, there are two sub cases: 1) "target" and 2) "over target." The target case corresponds to a realistic desired budget, and the over target case corresponds to a funding level that represents a maximum level that a particular program could manage.

For this particular project, ICF evaluated technology characteristics for the GPRA Program Funding Target case. NREL staff collected power generation technology characteristics developed by individual EERE programs for this case, and provided this information to ICF.

While the majority of technology characteristics are based on the GPRA Target Case, ICF did examine the GPRA Baseline Case (no R&D funding) to determine the impact of learning on

[37] Programs are listed on DOE EERE home page, http://www.eere.energy.gov/.

overnight capital costs. Learning associated with R&D was estimated to be represented by the difference in overnight capital costs between these two cases.

The GPRA 2009 data set includes power plant characteristics for five electricity generation technologies as indicated in Table 26. As noted, the GPRA 2009 data set includes characteristics for photovoltaic, solar thermal (concentrating solar power, or CSP), onshore wind, offshore wind, and geothermal technologies. PV characteristics are available for utility generation, commercial buildings, and residential buildings. Wind technologies are separated by location (onshore and offshore) and wind resource (Class 4 to 6 for onshore and class 6 to 7 for offshore). Geothermal is divided into hydrothermal binary, hydrothermal flash, and enhanced geothermal systems (EGS).

Table 26. Cost and Performance Characteristics in GPRA 2009

Technology	Description	Overnight Capital Cost (2006$/kW)	O&M, Fixed (2006$/kW/yr)	Heat Rate (Btu/kWh)	Life (yrs)
PV	Utility Generation	5,576	8.08	---	30
	Commercial Buildings	7,040	23.95	---	30
	Residential Buildings	7,761	85.20	---	30
Solar Thermal[38]	---	5,356	61.14	---	30
Wind, onshore	Class 4	1,448	27.60	---	20
	Class 5	1,448	27.60	---	20
	Class 6	1,448	27.60	---	20
Wind, offshore	Class 5, Shallow	2,865	180.00	---	20
	Class 6, Shallow	2,865	180.00	---	20
	Class 7, Shallow	2,865	180.00	---	20
Geothermal	Hydrothermal - Binary	4,623	119.28	---	---
	Hydrothermal - Flash	3,295	75.44	---	---
	EGS – Convective	4,212	148.01	---	---

Observations related to the technical performance and cost characteristics in the GPRA 2009 data set are included in the remainder of this section, which is organized as follows:

- Technical Performance Characteristics
    - Plant Size
    - Heat Rate
    - Capacity Factor
    - Plant Lifetime
- Cost Characteristics
    - Overnight Capital Costs
    - Learning
    - O&M Costs (fixed and variable)

[38] Solar thermal technology in the GPRA data set is based on concentrating solar power (CSP).

5.1.3 Technical Performance Characteristics

Plant Size

Power plant sizes were not provided for the GPRA data set. However, based on discussions with NREL personnel, the power plant sizes in the GPRA 2009 data set were assumed to be identical to the plant sizes in the AEO 2009 data set. These plant sizes are shown in Table 27.

Table 27. GPRA 2009, Power Plant Sizes[a]

Technology	Plant Size (MW)
PV (all types)	5
Solar Thermal	100
Wind, onshore (all types)	50
Wind, offshore (all types)	100
Geothermal	50

[a] Each technology is assumed to be equivalent to AEO.

Heat Rate

ICF only evaluated renewable technologies in the GPRA 2009 data set. Heat rates are primarily used to describe the performance of fossil technologies. Because ICF only evaluated renewable technologies in the GPRA 2009 data set, heat rates are not assessed in this report for the GPRA data set.

Capacity Factor

Capacity factors are provided for solar thermal, PV, onshore wind, offshore wind, and geothermal technologies in the GPRA data set. Geothermal technologies have the highest capacity factors – 90% for hydrothermal flash and 95% for EGS.

The onshore and offshore wind capacity factors are broken down by wind class as indicated in Figure 81. This figure shows that wind capacity factors improve over time for both onshore and offshore resources. These capacity factor improvements result from technology advancements, such as improved control systems and increased blade efficiencies, which expand the range of wind speeds that can be utilized. In general, the capacity factors increase by 10 to 15 percentage points for each wind class between the start of the modeling time period and approximately 2030. Between 2030 and 2050, the capacity factors remain relatively constant. In 2050, the lowest capacity factor is 40% (offshore Class 4) and the highest capacity factor is 54% (offshore Class 7).

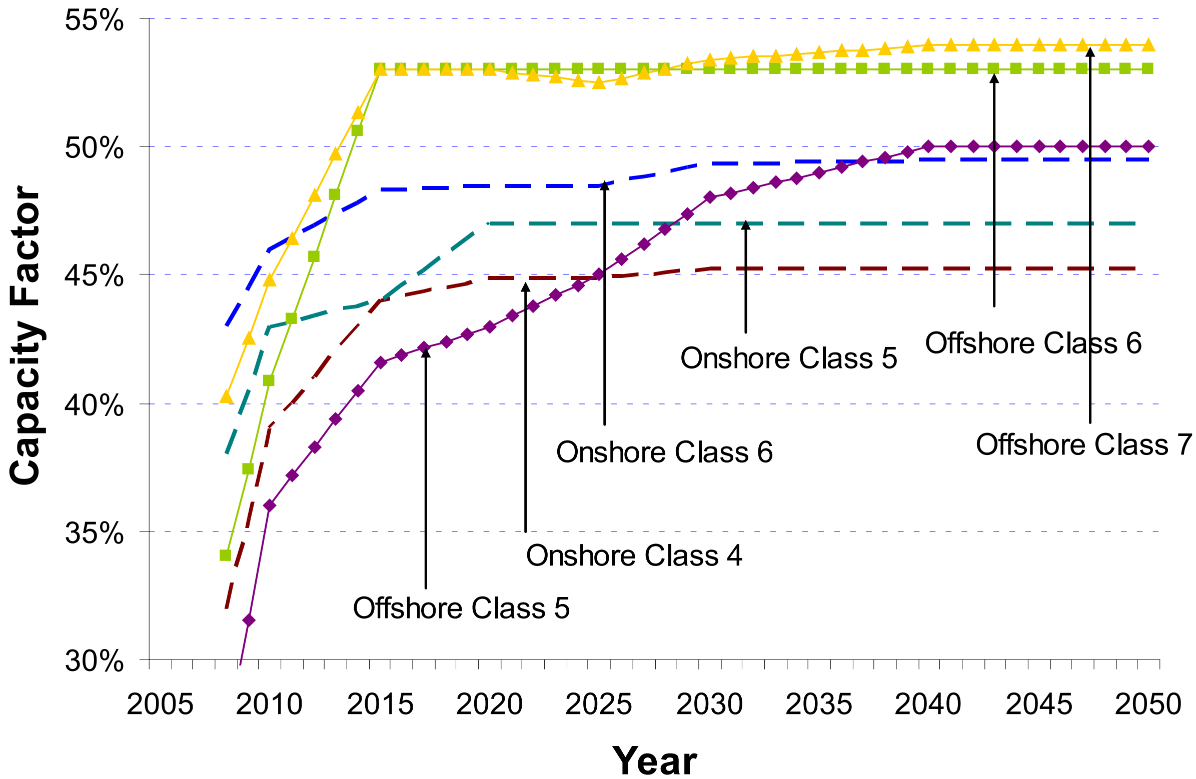


Figure 81. GPRA 2009, wind capacity factors

The solar thermal capacity factors for the GPRA data set are shown in Figure 82. As indicated, the capacity factor doubles between 2007 and 2030 – increase from 41% in 2007 to 82% in 2030 (remains constant at 82% beyond 2030). The reason for the rise in the solar thermal capacity factor is that the GPRA data set incorporates increasing levels of thermal storage over time. Thermal storage extends the energy delivery time, thereby increasing the capacity factor.

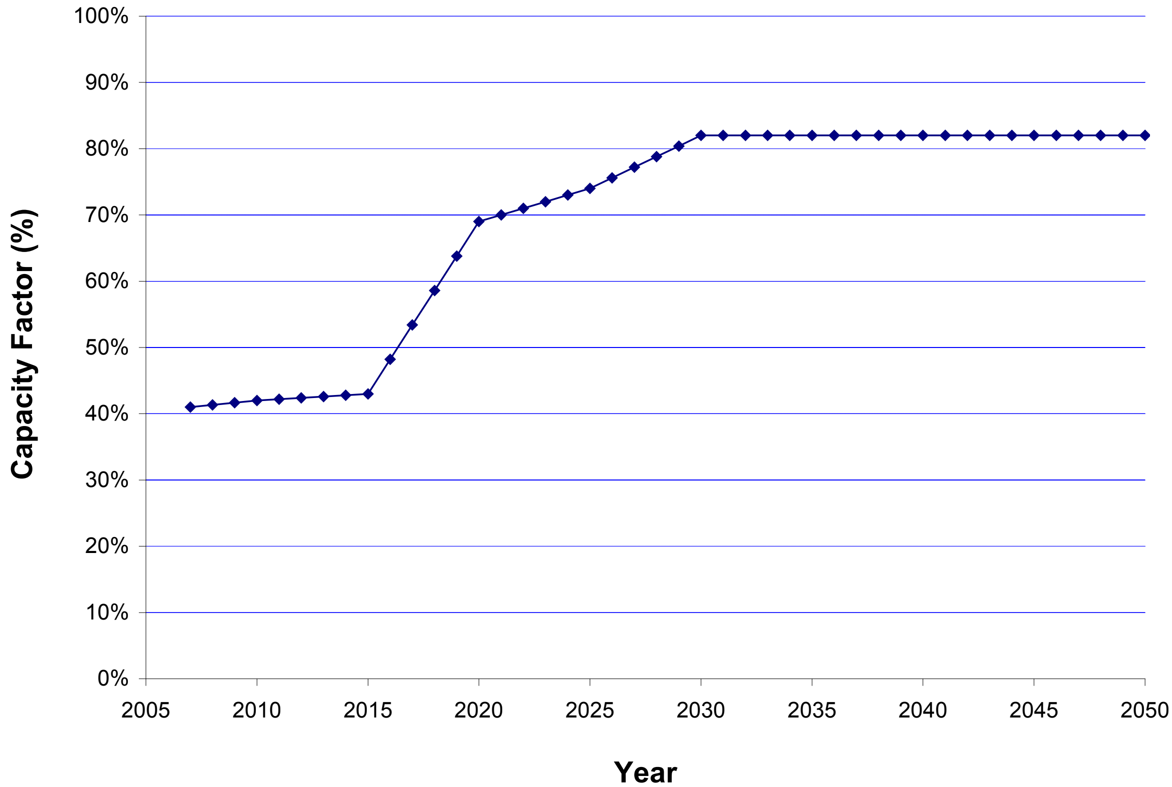


Figure 82. GPRA 2009, solar thermal capacity factors

Plant Lifetime

Plant lifetimes are shown in Table 26, and they remain constant over the GPRA 2009 modeling time frame. Plant life data are not reported in the GPRA 2009 data set for geothermal technologies (hydrothermal and EGS).

5.1.4 Cost Characteristics

Overnight Capital Costs

Table 28 shows the data points received from NREL for GPRA 2009 geothermal, PV, and solar thermal technologies. The data for geothermal technologies start in 2007 then continue in five year increments from 2010 to 2050. PV and solar thermal technologies also start in 2007, continue in five year increments from 2010 to 2030, and then jump to 2050. Overnight capital costs for geothermal, PV, and solar thermal technologies are expected to be decrease significantly during these years.

Table 28. GPRA 2009, Capital Cost for Non-Wind Renewable Technologies (2006$/Kw)

Year	Geothermal Hydrothermal Binary	Geothermal EGS	PV Commercial	PV Residential	PV Utility	Solar Thermal CSP
2007	$4,623	$4,212	$7,040	$7,761	$5,577	$5,356
2010	$4,533	$4,136	$4,019	$5,024	$3,919	$4,945
2015	$4,360	$3,989	$2,221	$3,316	$2,592	$4,223
2020	$4,232	$3,880	$1,888	$2,818	$2,204	$3,897
2025	$4,104	$3,772	$1,699	$2,396	$1,983	$3,586
2030	$3,975	$3,662	$1,614	$2,036	$1,884	$3,035
2035	$3,867	$3,563	--	--	--	--
2040	$3,754	$3,458	--	--	--	--
2045	$3,675	$3,374	--	--	--	--
2050	$3,639	$3,341	$1,533	$1,731	$1,790	$2,569

Table 29 shows capital costs for all wind technologies. Capital costs for onshore wind are similar in 2005; after 2010, however, onshore Classes 5 and 6 are about $100/kW lower than Class 4. All offshore wind classes have identical capital costs. The main differences between the wind categories are the capacity factors. In general, the higher the wind class the higher the capacity factor.

Table 29. GPRA 2009, Capital Cost for Wind Technologies (2006$/kW)

Year	Wind Class 4	Wind Class 5-6	Shallow Offshore Wind Class 5-7
2008	$1,448	$1,448	$2,865
2010	$1,422	$1,422	$2,812
2015	$1,300	$1,193	$1,984
2020	$1,225	$1,100	$1,700
2025	$1,136	$1,048	$1,600
2030	$1,118	$1,016	$1,468
2040	$1,102	$986	$1,443
2050	$1,080	$962	$1,418

Figure 83 compares the overnight capital costs of each technology for their base year. Not all costs in Figure 83 are from the same base year. Wind technologies have their first year of data in 2008 while the other technologies have their first year being 2007. There are 13 technologies because the GPRA data have variations within geothermal, PV, and wind.

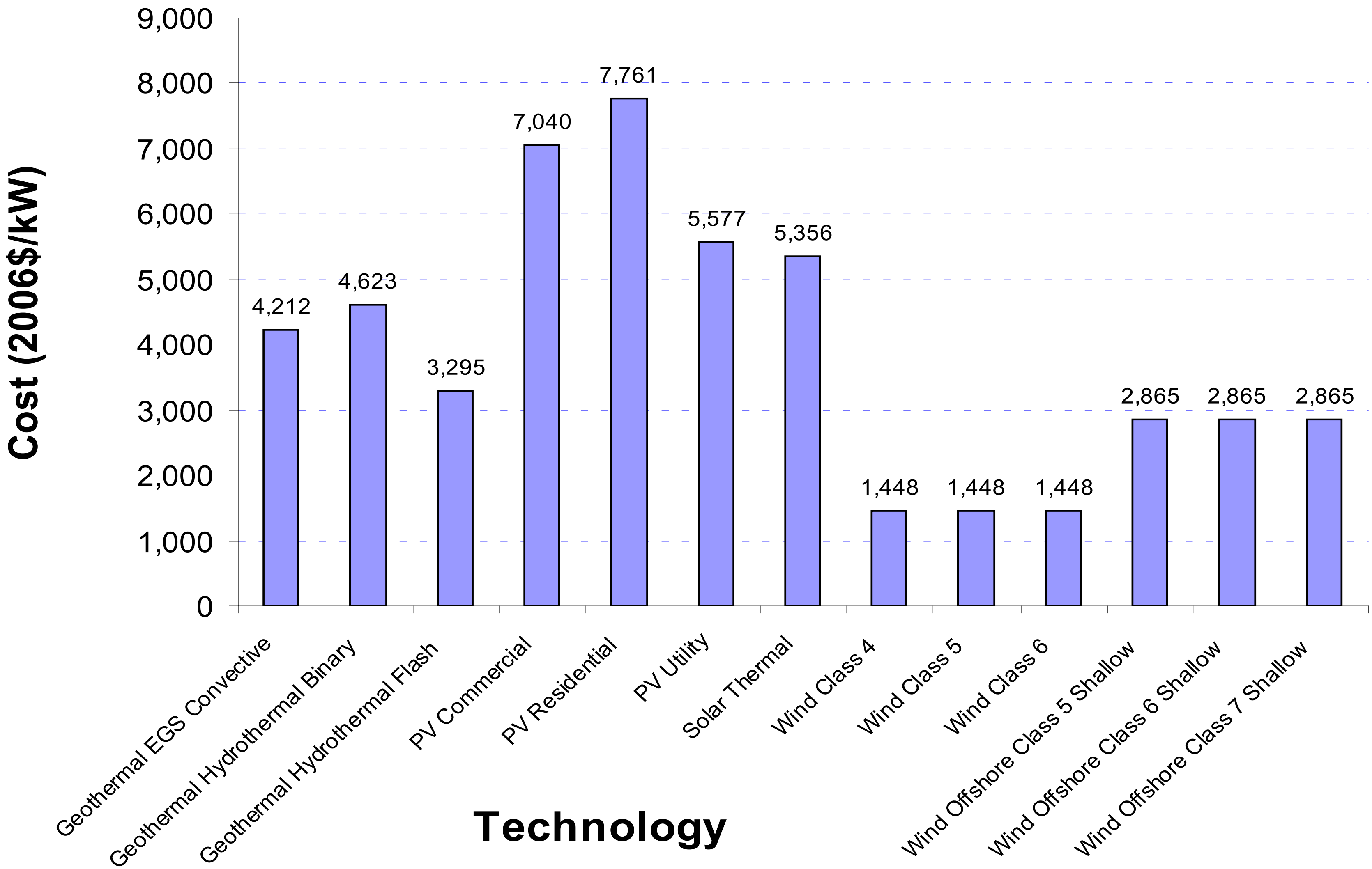


Figure 83. GPRA 2009, base overnight capital costs for 13 technologies

In Figure 84 shows overnight capital costs. Costs have been linearly interpolated to allow comparisons during gap years. PV for residential buildings begins as the highest cost of any of the technologies shown, but quickly drops below solar CSP and geothermal hydrothermal binary. Wind power (including Wind Offshore Class 5-7, not shown) has the lowest overnight capital costs of the technologies shown, for all years.

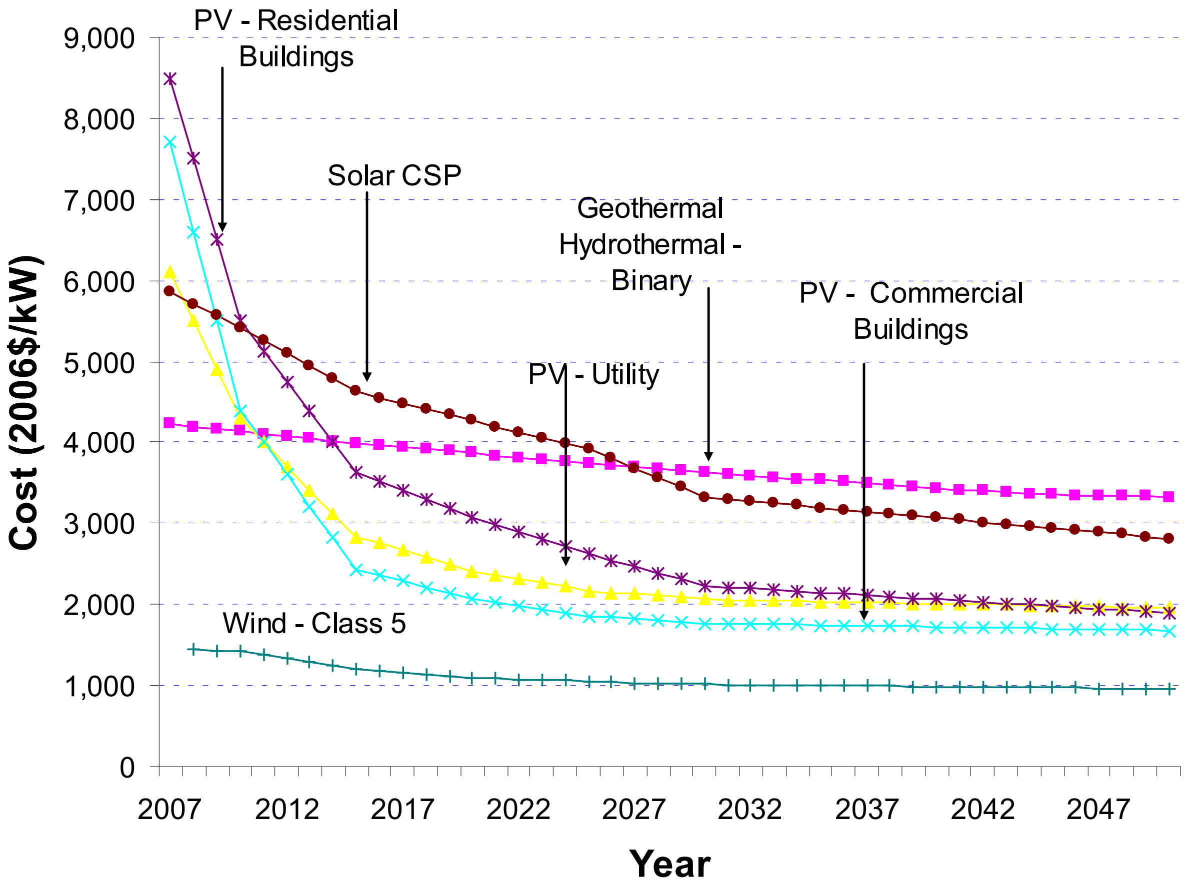


Figure 84. GPRA 2009, overnight capital costs

Learning

Capital costs are influenced by learning from R&D provided by the DOE in the GPRA data set. Learning is captured in the database by comparing the target case capital costs with the base case capital costs. Specifically, the formula below was used to calculate the learning factor:

$$\text{Learning Factor} = \frac{\text{Target Case Capital Cost}}{\text{Base Case Capital Cost}}$$

Learning factors were calculated for wind, PV, and geothermal technologies. The calculation was not made for solar thermal (CSP) because the characteristics of the technology in the target and base case were distinct. In the base case, CSP has no storage. In the target case, CSP has storage of 6 hours until 2015, 15 hours from 2020 to 2025, and 17 hour storage from 2030 forward[39].

In Figure 85, capital costs for onshore Wind Class 4 are shown over time. The lines show the actual capital costs for the base and target cases corresponding to the left axis. The blue bars show the calculated learning factors corresponding to the right axis. Capital costs are reduced by about 20 percent in Class 4 wind technology by 2050.

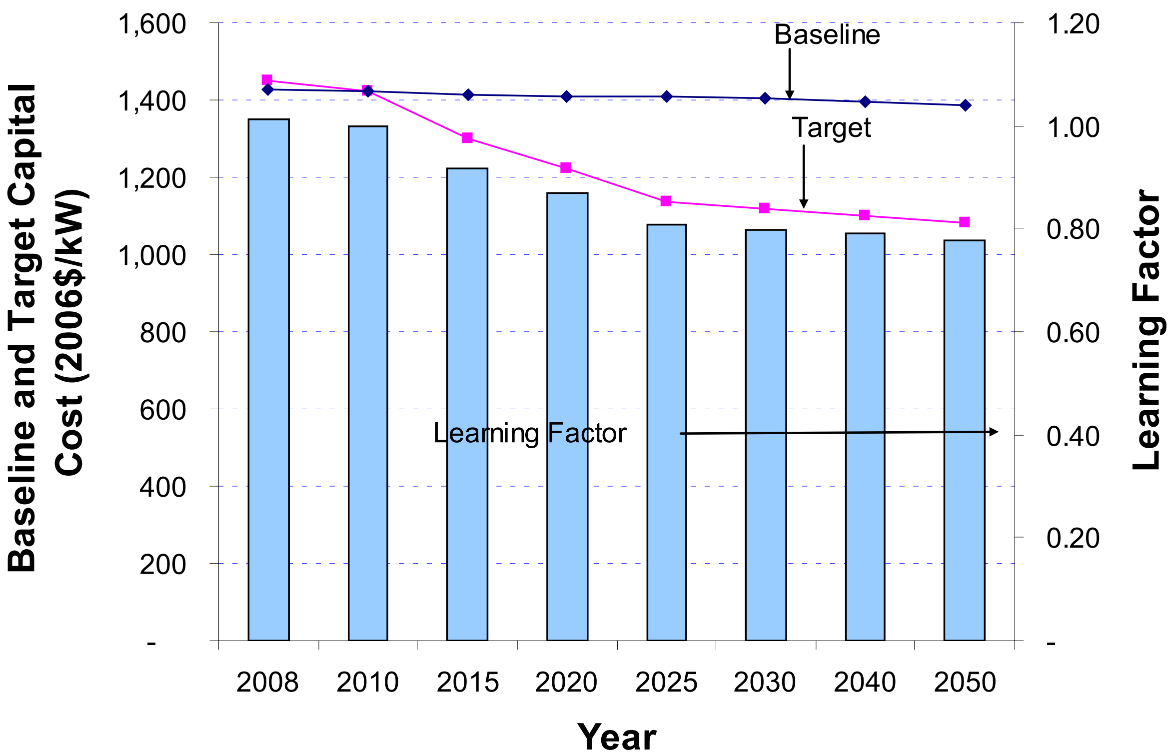


Figure 85. GPRA 2009, onshore wind class 4 capital costs (base and target cases)

Wind Classes 5 and 6 experience the same cost improvement from learning. Both wind classes are modeled with the same capital costs in the base and target cases. Capital costs decrease by over 30 percent by 2050. Figure 86 shows the capital costs and learning factor over time for onshore Wind Classes 5 and 6.

Offshore wind has the same target and base case costs across all classes. The decrease in cost due to learning is shown in Figure 87. Offshore wind capital costs are projected to decrease by nearly 50 percent by 2050, perhaps due to advances in offshore structure designs.

---

[39] Information based on spreadsheet sent by NREL on September 11, 2009 (Solar-PDS FY10 Submission- CSP-Mehos revised- 4-13-08.xls).

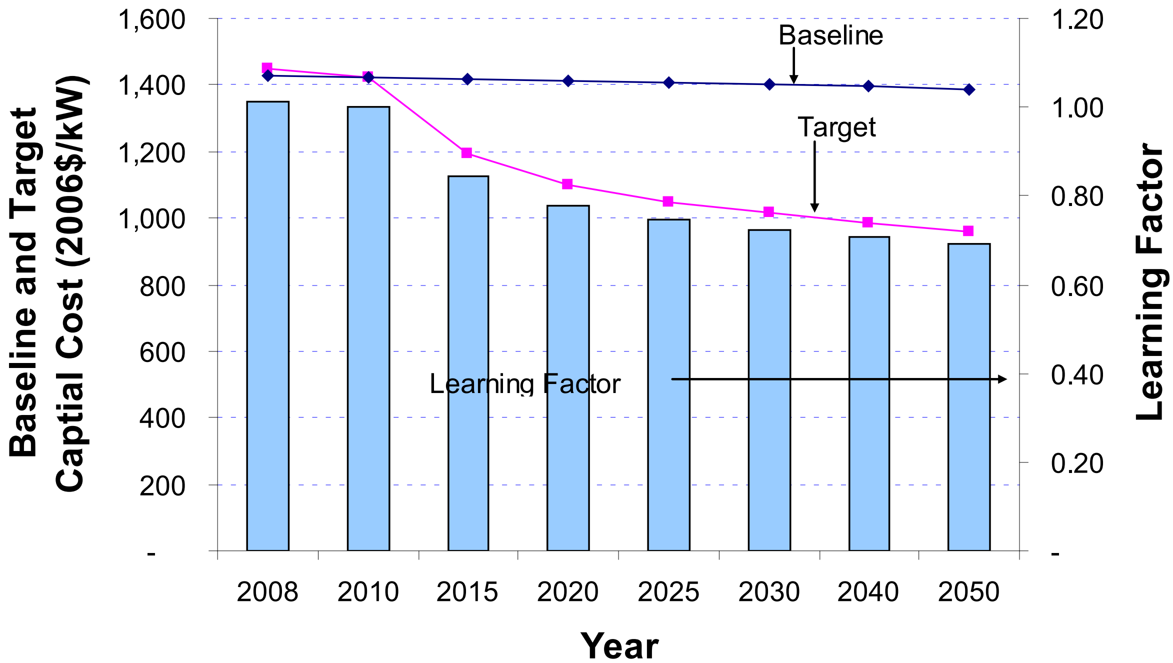


Figure 86. GPRA 2009, onshore wind classes 5 and 6, capital costs

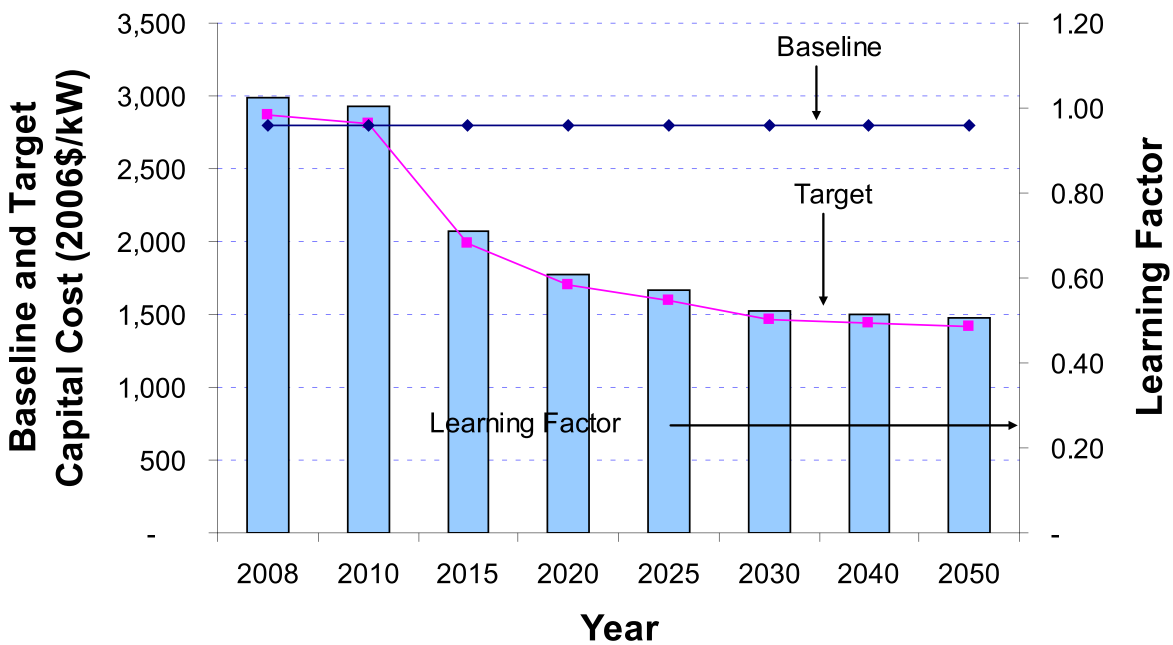


Figure 87. GPRA 2009, shallow offshore wind class 4, capital costs

Learning in geothermal technologies is depicted in the following three figures. Although the target case data extends to 2050, the base case data only extends to 2030. Therefore, learning factors are only calculated to 2030.

Figure 88 and Figure 89 show the capital costs and learning factors for both geothermal hydrothermal technologies. Both technologies have the same learning factors. However, the actual costs are different. Binary technology is more expensive on a per kilowatt basis. Capital costs for geothermal binary start at $4,337 per kW while geothermal flash technology starts at $3,091 per kW in 2007. Both decrease by 25 percent by 2030.

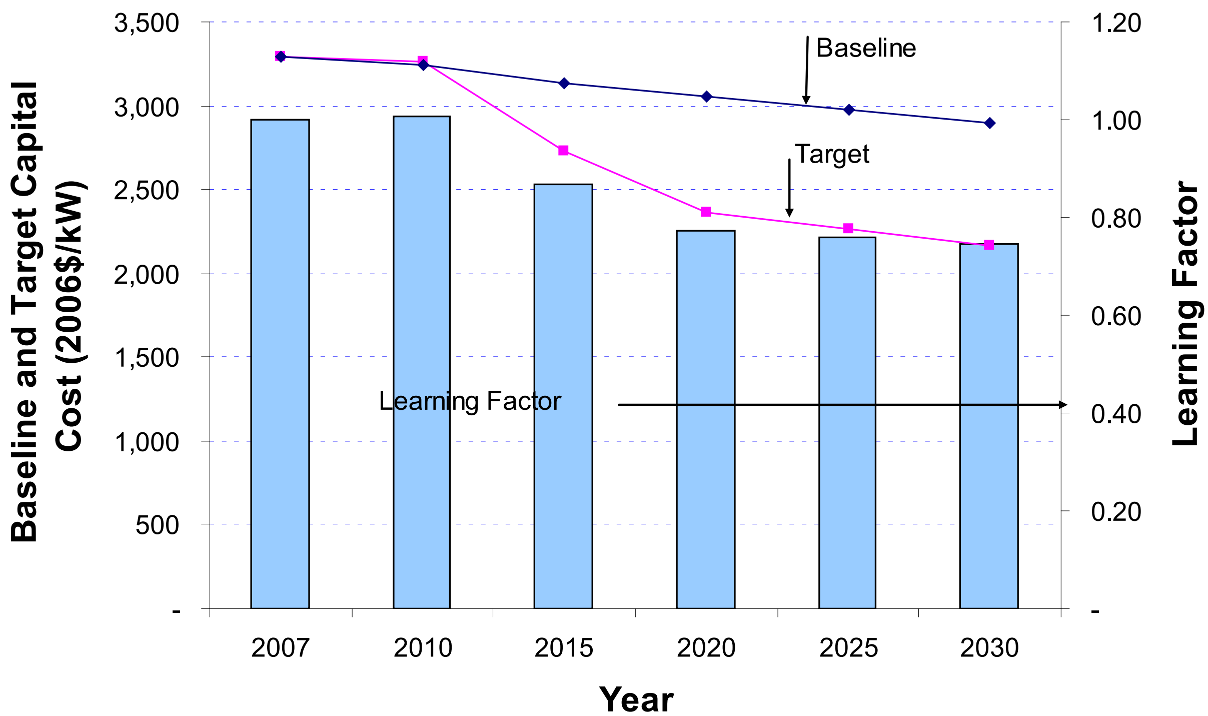


Figure 88. GPRA 2009, geothermal flash learning factor

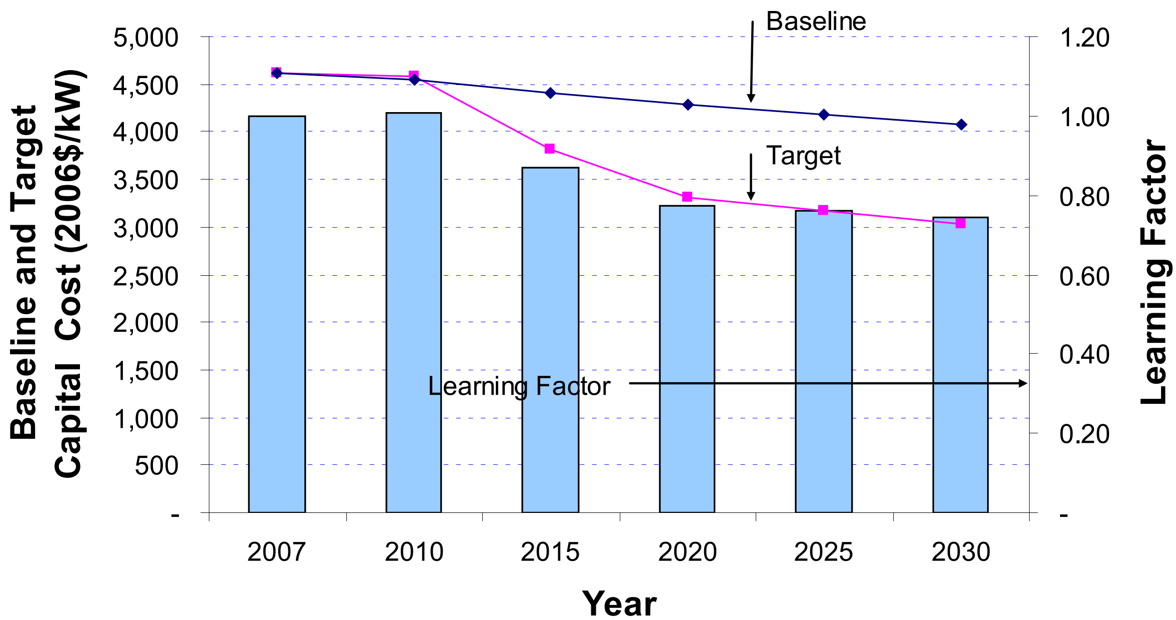


Figure 89. GPRA 2009, geothermal binary learning factor

Geothermal EGS – convective technology has a smaller decrease in cost due to learning than either hydrothermal technology. By 2030, the decrease is less than 20 percent. Figure 90 shows the capital costs in the baseline and target cases and the learning factor for geothermal EGS.

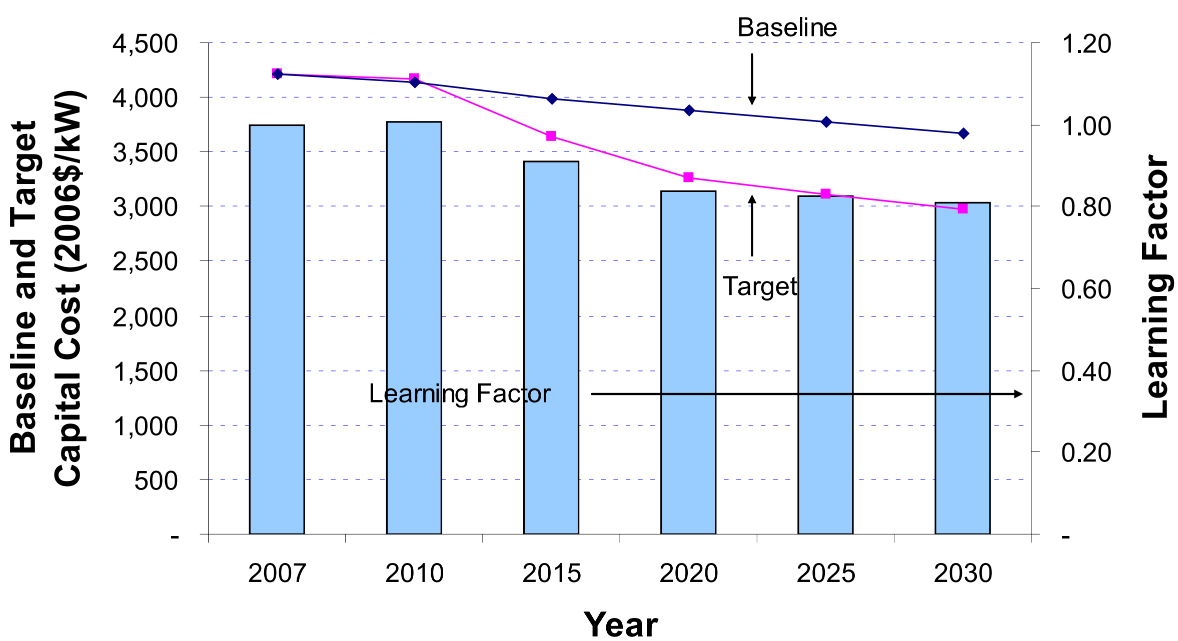


Figure 90. GPRA 2009, geothermal EGS—convective learning factor

The GPRA data have three classifications for photovoltaic (PV) technologies: residential, commercial, and utility. In the data provided by NREL, residential and commercial PV extend to 2050, while utility only extends to 2025. Figure 91 and Figure 92 show the costs of residential and commercial PV in the different cases and their learning factors. The learning effect trend in residential and commercial PV is different from the learning found in the other GPRA renewable technologies. Gains from learning by DOE R&D are realized in the early part of the modeling horizon, and the baseline cost almost converges with the target case by 2050. Contrast these trends with geothermal and wind, where the baseline case never begins to converge with the target case.

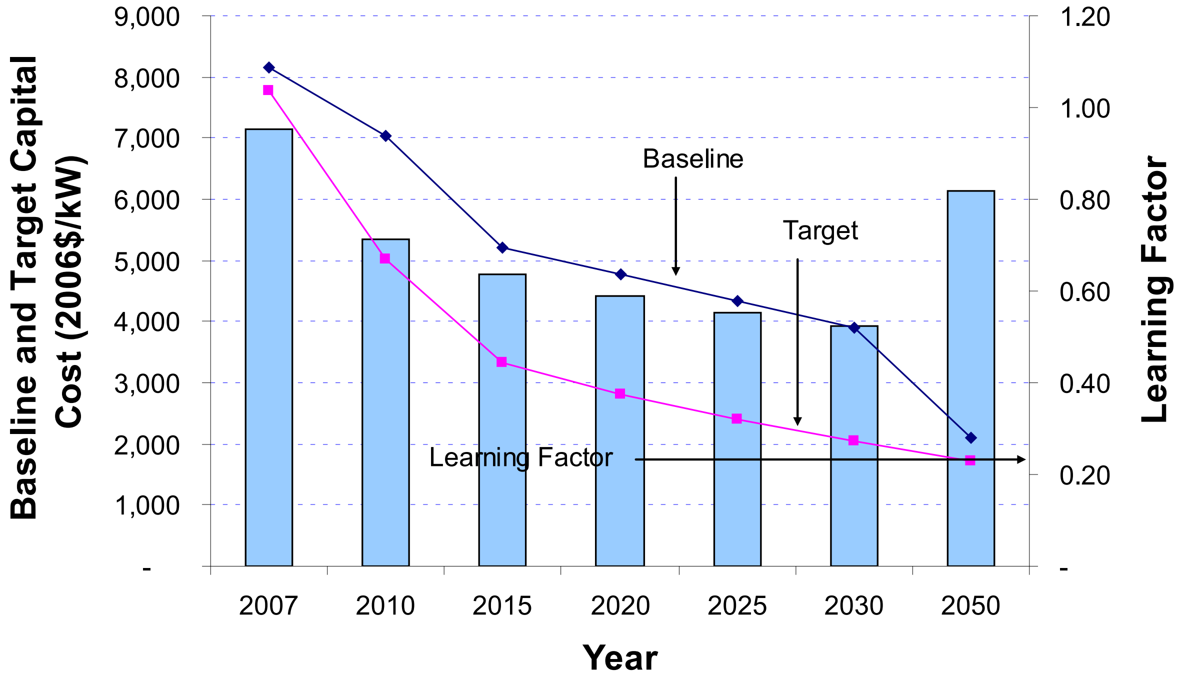


Figure 91. GPRA 2009, residential PV learning factor

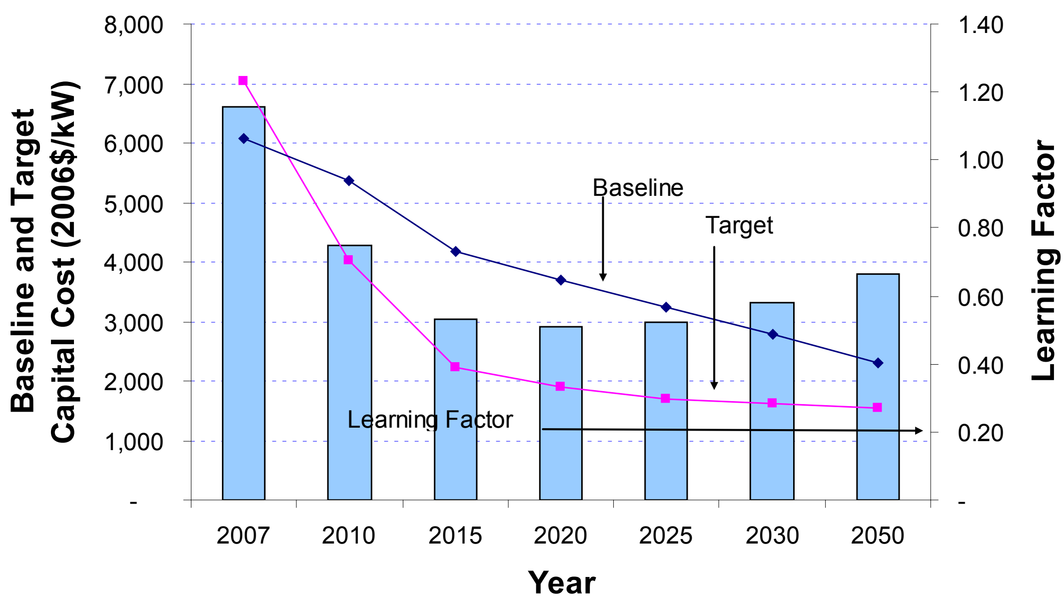


Figure 92. GPRA 2009, commercial PV learning factor

Figure 93 shows the capital costs in the target and baseline cases and learning factor of utility PV in GPRA. There is no convergence of capital costs between 2007 and 2025 in utility PV. To be fair, residential PV did not converge between 2007 and 2025, either. All of its convergence occurs between 2030 and 2050, when there is expected to be a significant decrease in the baseline capital cost.

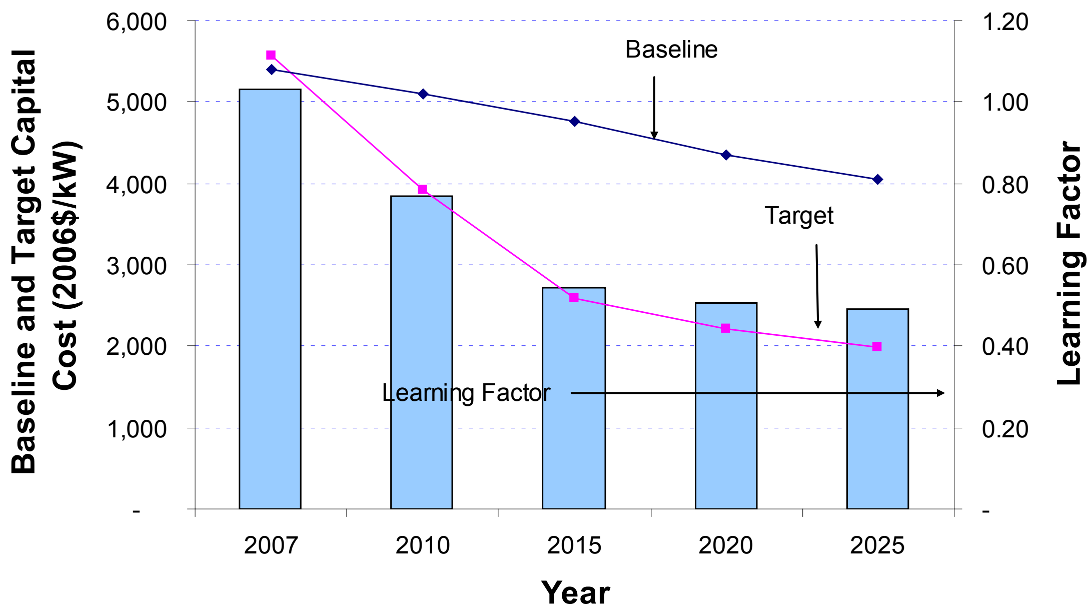


Figure 93. GPRA utility PV learning factor

O&M Costs

In the GPRA data set, O&M costs change for all renewable technologies over the modeling horizon (2005 through 2050). O&M cost data received from NREL is shown in Table 30.

Table 30. GPRA 2009, Fixed O&M Costs (2006$/kW/yr) for Renewable Technologies

Year	Geothermal Hydrothermal Binary	PV Commercial	PV Residential	PV Utility	Solar Thermal CSP	Shallow Offshore Wind Class 5	Wind Class 5
2007	$119.28	$23.95	$85.20	$8.08	$61.14	--	--
2008	--	--	--	--	--	$180.00	$27.60
2010	$119.68	$12.06	$15.07	$7.00	$52.11	$180.00	$25.98
2015	$116.75	$4.44	$6.63	$5.18	$48.52	$127.00	$24.08
2020	$113.82	$3.21	$4.79	$3.75	$44.94	$110.00	$22.29
2025	$110.88	$2.60	$3.88	$3.03	$41.34	$80.00	$20.61
2030	$107.95	$2.35	$3.50	$2.74	$37.73	$55.00	$19.15
2035	$105.08	--	--	--	--	--	--
2040	$102.25	--	--	--	--	$50.00	$16.46
2045	$100.04	--	--	--	--	--	--
2050	$99.06	$2.12	$3.16	$2.47	$22.91	$45.00	$14.11

Figure 94 shows the fixed O&M costs for six of the renewable technologies. Costs from the table have been linearly interpolated in the figure to allow comparisons during gap years. Solar CSP has base O&M costs in 2005, but, from 2010 through 2050, it has costs in ten year increments.

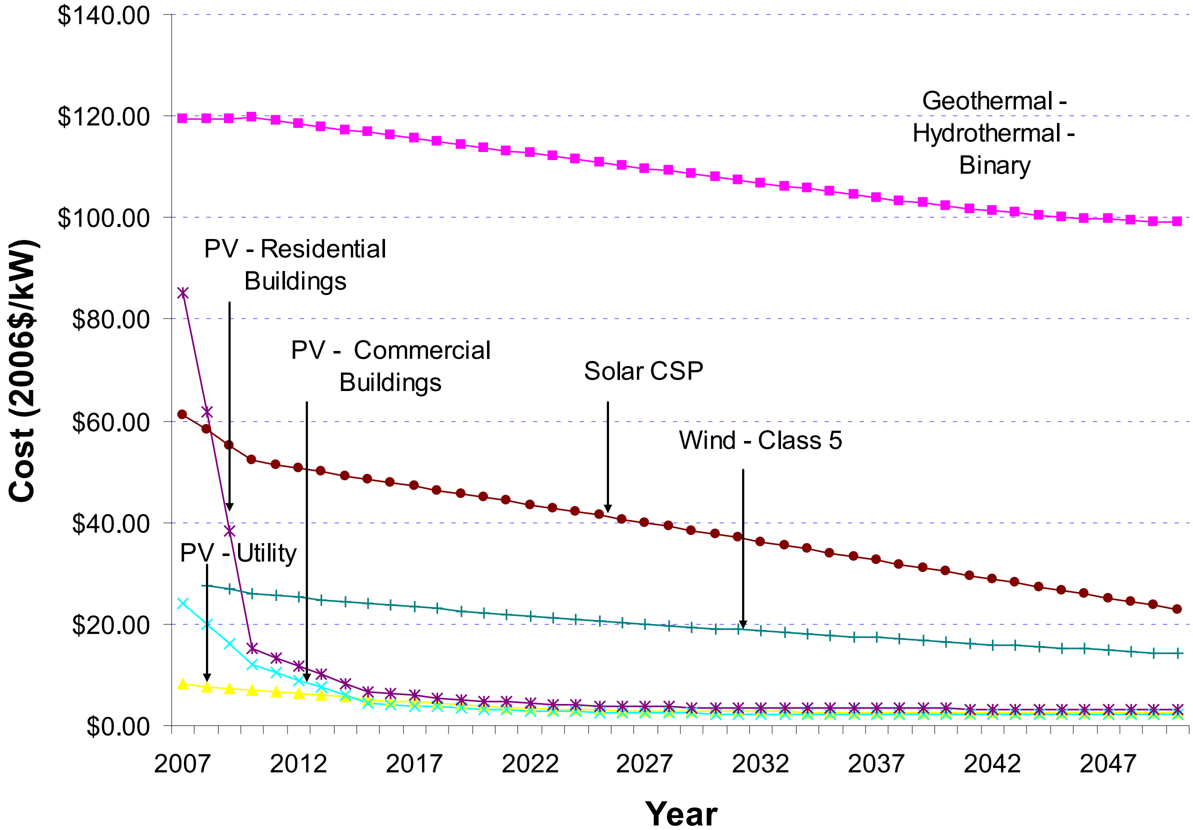


Figure 94. GPRA 2009, fixed annual O&M costs for renewable technologies

Appendix C. ReEDS (NREL-SEAC 2008 Data Set)

NREL developed the ReEDS model and is responsible for developing the power plant characteristics that are used to support the model. In general, the available generator types in the ReEDS data set are based on the most likely types identified by EIA in the latest Annual Energy Outlook.[40]

While the generator types in the ReEDS data set are generally consistent with the EIA Annual Energy Outlook, the ReEDS power plant characteristics generally differ from AEO. NREL uses internal resources, including contractor support from firms such as Black & Veatch, to develop power plant characteristics. As part of the process for developing power plant characteristics for ReEDS, NREL analyzes the full spectrum of power generation technologies, including fossil and nuclear as well as renewable.

For this project, NREL provided ICF with a data set used in conjunction with a Department of Energy 20% wind penetration study conducted in 2008 and a 20% National Renewable Portfolio Standard study.[41][42] This data set is referred to as NREL-SEAC 2008.

The NREL-SEAC 2008 data set used in the ReEDS model has cost and performance characteristics for 22 electricity generation technologies projected to 2050. For each technology, the data include three cost parameters (overnight capital cost, variable O&M, and fixed O&M) and two technical performance characteristics (heat rate and plant life). Table 31 lists the 22 technologies and the five characteristics – three cost and two technical performance parameters – for the 2008 data set.

In the NREL-SEAC 2008 data set, wind and solar thermal are divided into five resource classes. Also, the offshore wind is separated into deep and shallow categories. Each wind category (onshore, shallow offshore, and deep offshore) has five wind resource classes that affect only the capacity factor. The solar resource class does not affect the solar thermal capacity factor. The resource class does not affect the cost parameters or plant life of wind or solar thermal.

NREL-SEAC data cost projections are provided in five year intervals from 2000 to 2050 for all technologies except geothermal technologies. Geothermal technologies are separated by three characteristics: (1) hydrothermal or EGS, (2) geo classes, and (3) geographic regions. In NREL-SEAC data, there is no distinction between flash and binary. Geothermal hydrothermal is used to model both flash and binary.

Wind and storage technologies are the main distinguishing characteristics in the NREL-SEAC data set. Three storage technologies (battery, CAES, and ICE-storage) were included in the data set but were not found in the other data sets listed in Table 1. Also, NREL-SEAC is similar to only the GPRA data set in that wind is separated by wind class for both onshore and offshore resources.

[40] ReEDS Model Documentation, Base Case Data and Model Description, Conventional Generation (Section 2.5), p28, W. Short et al., August 2009.
[41] 20% Wind Energy by 2030, DOE EERE, DOE/GO-102008-2567, July 2008.
[42] Evaluating a Proposed 20% National Renewable Portfolio Standard. NREL Technical Report. NREL/TP-6A2-45161. February 2009.

Observations related to the technical performance and cost characteristics in the NREL-SEAC 2008 data set are included in the remainder of this section, which is organized as follows:

- Technical Performance Characteristics
    - Plant Size
    - Heat Rate
    - Capacity Factor
    - Plant Lifetime
- Cost Characteristics
    - Overnight Capital Costs
    - Learning
    - O&M Costs (fixed and variable)

Table 31. NREL-SEAC 2008, Summary of Characteristics for 2005[43]

Technology	Overnight Capital Cost (2004$/kW)	Variable O&M (2004$/MWh)	Fixed O&M (2004$/kW/yr)	Heat Rate (Btu/kWh)	Lifetime (Years)	Plant Size (MW)
Advanced Combined Cycle (CC)	742	2.86	13.71	6,870	30	300
Adv CC with Carbon Capture	1,371	8.09	--	7,790	30	400
Adv Combustion Turbine (CT)	595	11.42	7.33	11,560	30	160
Biomass	2,617	9.52	66.63	14,500	45	100
Cofire New	2,048	1.62	34.65	9,470	60	600
Cofire Old	1,234	3.40	24.46	10,000	60	600
Conventional Hydro	1,320	3.20	12.72	--	100	200
Geothermal EGS[44]	6,998	--	199.69	--	20	50
Geothermal Hydrothermal[45]	2,818	--	159.41	--	20	50
IGCC	2,617	3.71	36.26	9,000	60	550
IGCC with Carbon Capture	3,475	8.09	30.00	9,700	60	380
MSW-Landfill Gas	3,475	9.52	66.63	15,628	30	600
Nuclear	3,103	0.48	85.66	10,400	60	1,000
Oil-Gas-Steam	396	3.16	25.26	9,000	50	250
PV	5,000	--	70.00	--	30	100
Scrubbed Coal New	2,018	1.62	33.60	9,470	60	600
Scrubbed Coal Old	1,204	3.40	23.41	10,000	60	600
Unscrubbed Coal	1,000	3.94	27.16	10,000	60	600
Wind, Onshore Classes 3-7	1,570	6.66	10.95	--	20	100
Wind, Offshore Deep Classes 3-7	3,046	22.84	14.28	--	20	100
Wind, Offshore Shallow Classes 3-7	2,284	19.99	14.28	--	20	100
Solar Thermal Classes 1-5	5,850	0.10	55.72	--	30	200

[43] In addition to the power generation technologies shown in the table, the NREL-SEAC 2008 data set also contains characteristics for four energy storage technologies: batteries, compressed air energy storage (CAES), ice storage, and pumped hydro.
[44] Geothermal EGS capital costs and O&M costs were developed using the methodology described in Section 4.2 (geothermal cost methodology). For reference, capital costs had a standard deviation of $196 (2.8%), and fixed O&M costs had a standard deviation of $1.31 (0.7%).
[45] Geothermal hydrothermal capital costs and O&M costs were developed using the methodology described in Section 4.2 (geothermal cost methodology). For reference, capital costs had a standard deviation of $650 (23.1%), and fixed O&M costs had a standard deviation of $35.07 (22%).

5.1.5 Technical Performance Characteristics

Plant Size

In the NREL-SEAC model, plant size is not a critical parameter, and is often only used for statistical purposes. Representative nominal plant sizes used in the NREL-SEAC model are shown in Table 31.

Heat Rate

Heat rates for six of the 26 technologies in each NREL-SEAC data set are listed in Table 32**.** Geothermal technologies do not have heat rates in NREL-SEAC. Many heat rates are constant with time (combined cycle, nuclear, and biomass), but the others drop about 20% from 2005.

Table 32. NREL-SEAC 2008, Heat Rates for Six Technologies

Year	Comb Turbine	Comb Cycle	Coal	Nuclear	IGCC	Biomass
2000	11,560	6,870	8,470	10,400	9,000	14,500
2005	11,560	6,870	9,470	10,400	9,000	14,500
2010	8,900	6,870	9,200	10,400	9,000	14,500
2015	8,900	6,870	9,100	10,400	9,000	14,500
2020	8,900	6,870	9,000	10,400	8,900	14,500
2025	8,900	6,870	9,000	10,400	8,900	14,500
2030	8,900	6,870	9,000	10,400	8,580	14,500
2035	8,900	6,870	9,000	10,400	8,580	14,500
2040	8,900	6,870	9,000	10,400	8,580	14,500
2045	8,900	6,870	9,000	10,400	8,580	14,500
2050	8,900	6,870	9,000	10,400	8,580	14,500

Figure 95 compares heat rates (linearly interpolated to provide annual data during gap years) between technologies in the NREL-SEAC 2008 data set. Biomass technology has the highest heat rate in both data sets. Combined cycle remains the most efficient in the data set, with a heat rate of 6,870 Btu/kWh.

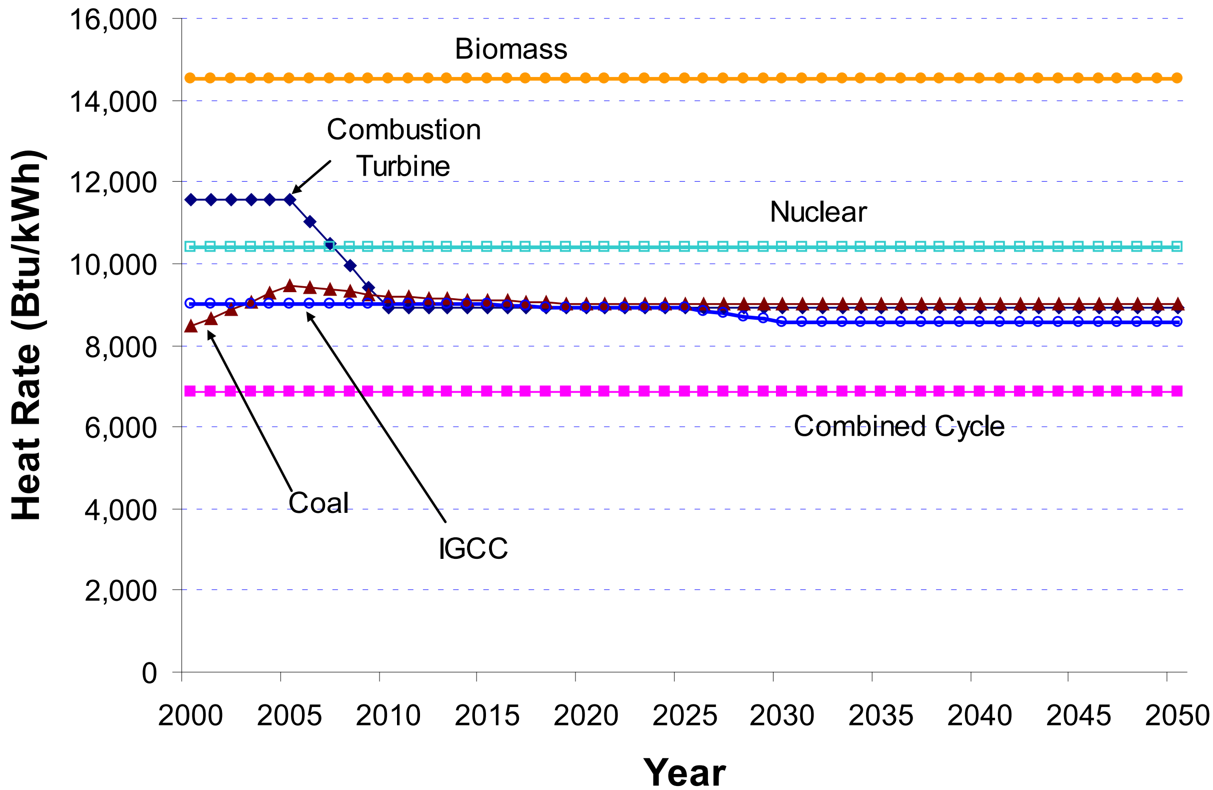


Figure 95. NREL-SEAC 2008, heat rates for six technologies

Capacity Factors

NREL provided capacity factors for all renewable technologies. For non-renewable technologies, capacity factors were calculated from planned outage rate data provided by NREL as follows:

Calculated Capacity Factor (%) = 100% - Planned Outage (%)

Capacity factors for technologies in the NREL-SEAC 2008 data set are shown in Table 33. This table contains data for renewable and non-renewable technologies in five year increments between 2000 and 2050.

Table 33. NREL-SEAC 2008, Capacity Factors

Technology		Capacity Factors (%) by Year										
		2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Wind, onshore	Class 3	18.5	32.0	35.0	36.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
	Class 4	18.5	36.0	39.0	41.0	42.0	42.5	43.0	43.0	43.0	43.0	43.0
	Class 5	18.5	40.1	43.0	44.0	45.0	45.5	46.0	46.0	46.0	46.0	46.0
	Class 6	18.5	44.0	46.0	47.0	48.0	48.5	49.0	49.0	49.0	49.0	49.0
	Class 7	18.5	47.0	50.0	51.0	52.0	52.5	53.0	53.0	53.0	53.0	53.0
Wind, offshore, shallow	Class 3	34.0	34.0	37.0	38.0	39.0	39.5	40.0	41.0	42.0	42.0	42.0
	Class 4	38.0	38.0	41.0	43.0	44.0	44.5	45.0	45.0	45.0	45.0	45.0
	Class 5	42.0	42.0	45.0	46.0	47.0	47.5	48.0	48.0	48.0	48.0	48.0
	Class 6	46.0	46.0	48.0	50.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Class 7	50.0	50.0	52.0	54.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
Wind, offshore, deep	Class 3	38.0	38.0	38.0	38.0	39.0	39.5	40.0	40.0	40.0	40.0	40.0
	Class 4	43.0	43.0	43.0	43.0	44.0	44.5	45.0	45.0	45.0	45.0	45.0
	Class 5	46.0	46.0	46.0	46.0	47.0	47.5	48.0	48.0	48.0	48.0	48.0
	Class 6	50.0	50.0	50.0	50.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Class 7	54.0	54.0	54.0	54.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
Solar Thermal	Class 1	21.8 (same for all years)										
	Class 2	27.8 (same for all years)										
	Class 3	31.2 (same for all years)										
	Class 4	32.0 (same for all years)										
	Class 5	33.3 (same for all years)										
PV		21.0 (same for all years)										
Coal		84.6 (same for all years)										
IGCC		81.0 (same for all years)										
Combustion Turbine		80.0 (same for all years)										
Combined Cycle		84.6 (same for all years)										
Nuclear		90.2 (same for all years)										
Biomass		84.0 (same for all years)										
Geothermal		84.6 (same for all years)										

Figure 96 compares capacity factors for onshore wind with a breakdown by wind class. As expected, capacity factors are higher for wind resources that have higher wind speeds (wind speeds increase as class designations increase). Across all onshore wind classes, capacity factors improve over time. The largest improvement for the time period examined is between 2000 and 2005. After 2005, improvements still occur, but at lower rates compared to the initial five year period. By 2050, the onshore wind capacity factors range from 38% (Class 3) to 53% (Class 7).

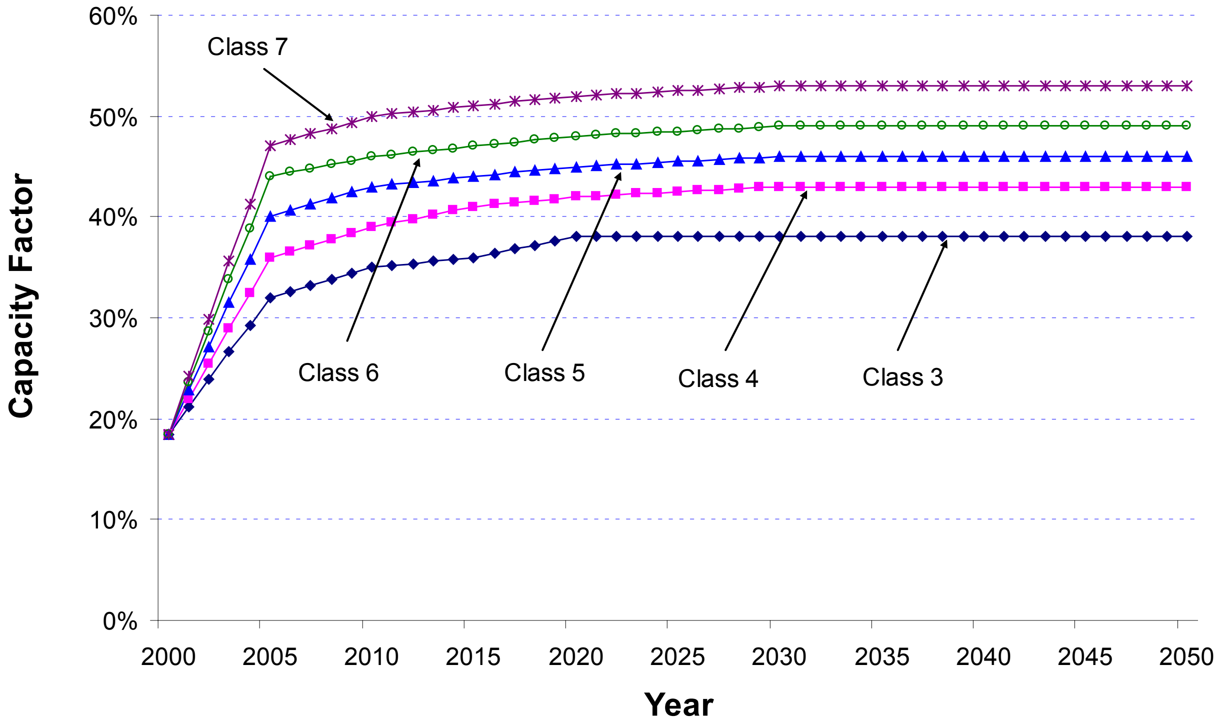


Figure 96. NREL-SEAC 2008, capacity factors, onshore wind

Offshore wind technologies – both shallow and deep – show modest improvements in capacity factor over time (see Figure 97 and Figure 98, respectively). Shallow offshore wind capacity factors are in the range of 34-50% in 2000, and then increase to a range of 42-55% in 2050. For deep offshore, capacity factors are 38-54% in 2000, and increase to 40-55% in 2050.

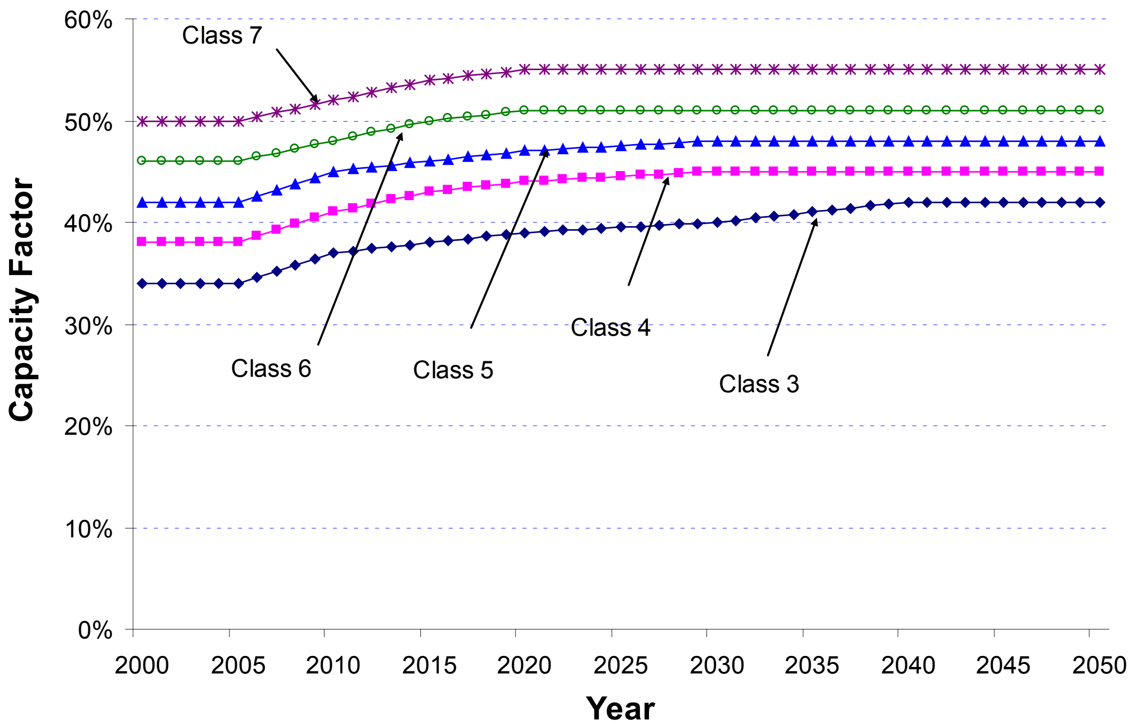


Figure 97. NREL-SEAC 2008, capacity factors, shallow offshore wind

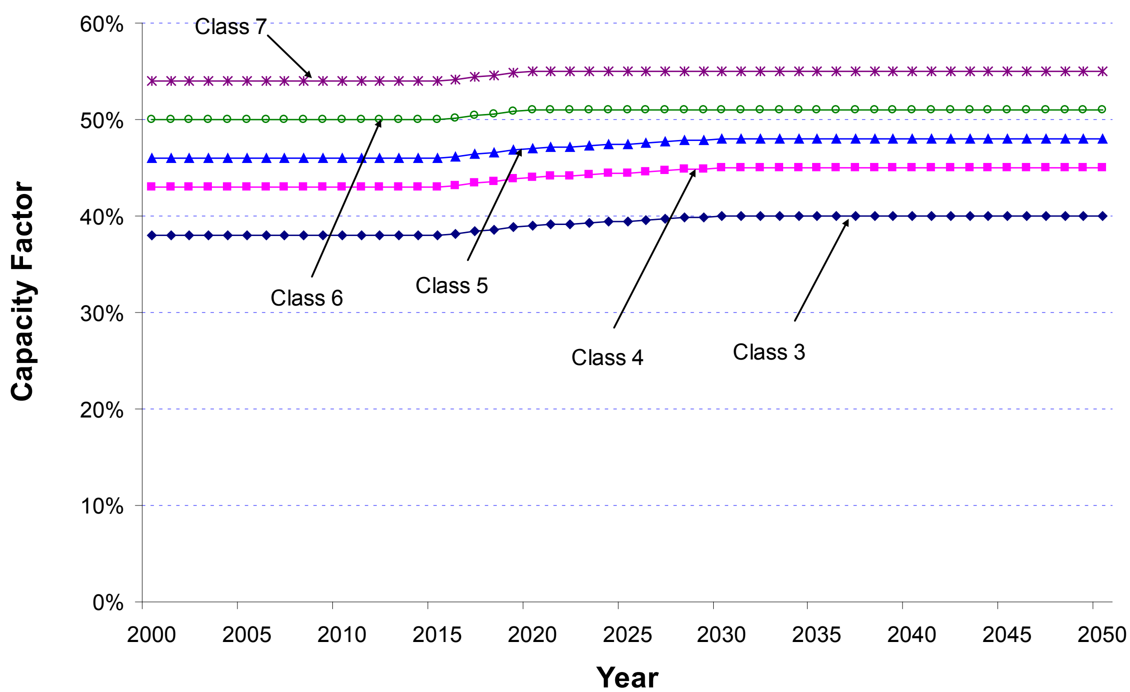


Figure 98. NREL-SEAC 2008, capacity factors, deep offshore wind

Figure 99 shows solar thermal and PV capacity factors in the NREL-SEAC 2008 data set. Capacity factors for solar thermal are divided into five classes – Class 1 through Class 5. For a given class, the capacity factors do not change over time. However, the capacity factors do increase with the quality of the solar thermal resource (quality increases as class increases). The solar thermal capacity factors range from approximately 22% (Class 1) to 33% (Class 5). In the NREL-SEAC 2008 data set, the capacity factor for PV technology remains constant at 21% – slightly below Class 1 solar thermal.

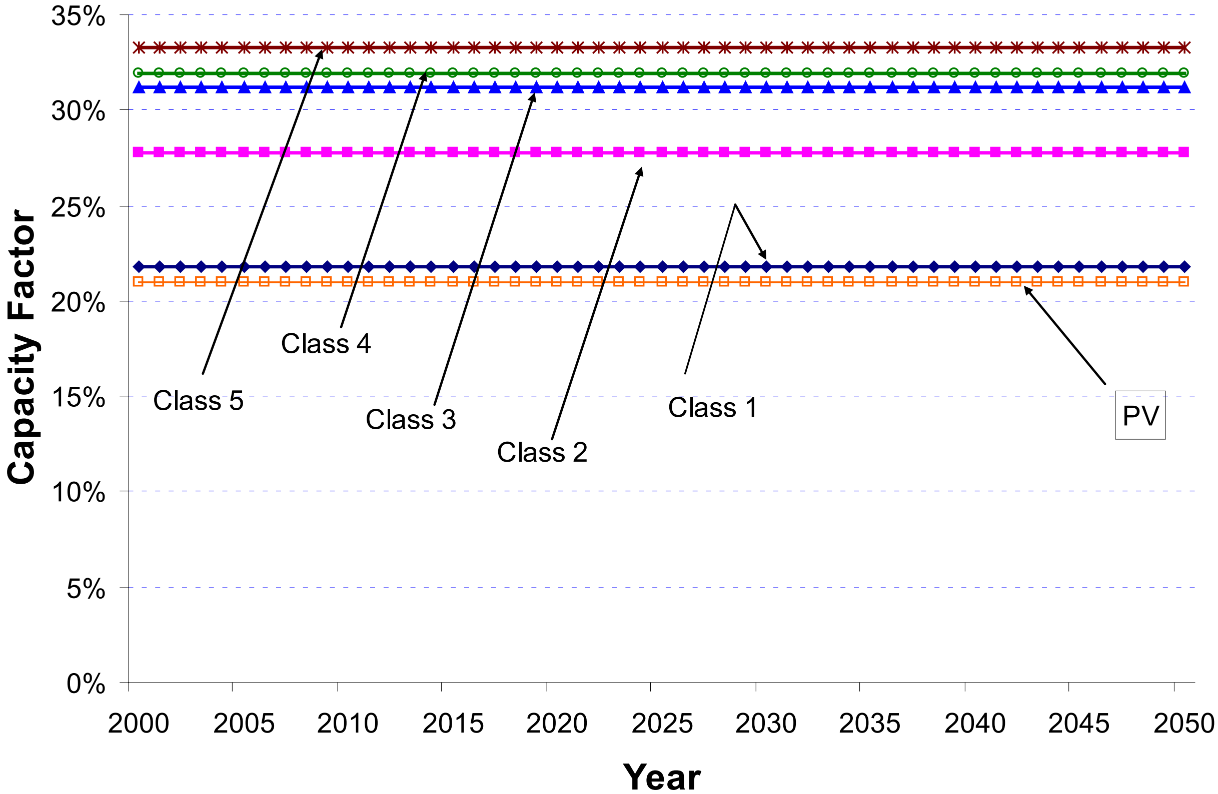


Figure 99. NREL-SEAC 2008, capacity factors, solar thermal and PV

In the NREL-SEAC 2008 data set, capacity factors for coal, IGCC, combustion turbine, combined cycle, nuclear, biomass, and geothermal technologies remain constant over the time horizon of 2000 through 2050. These capacity factors are shown in Figure 100.

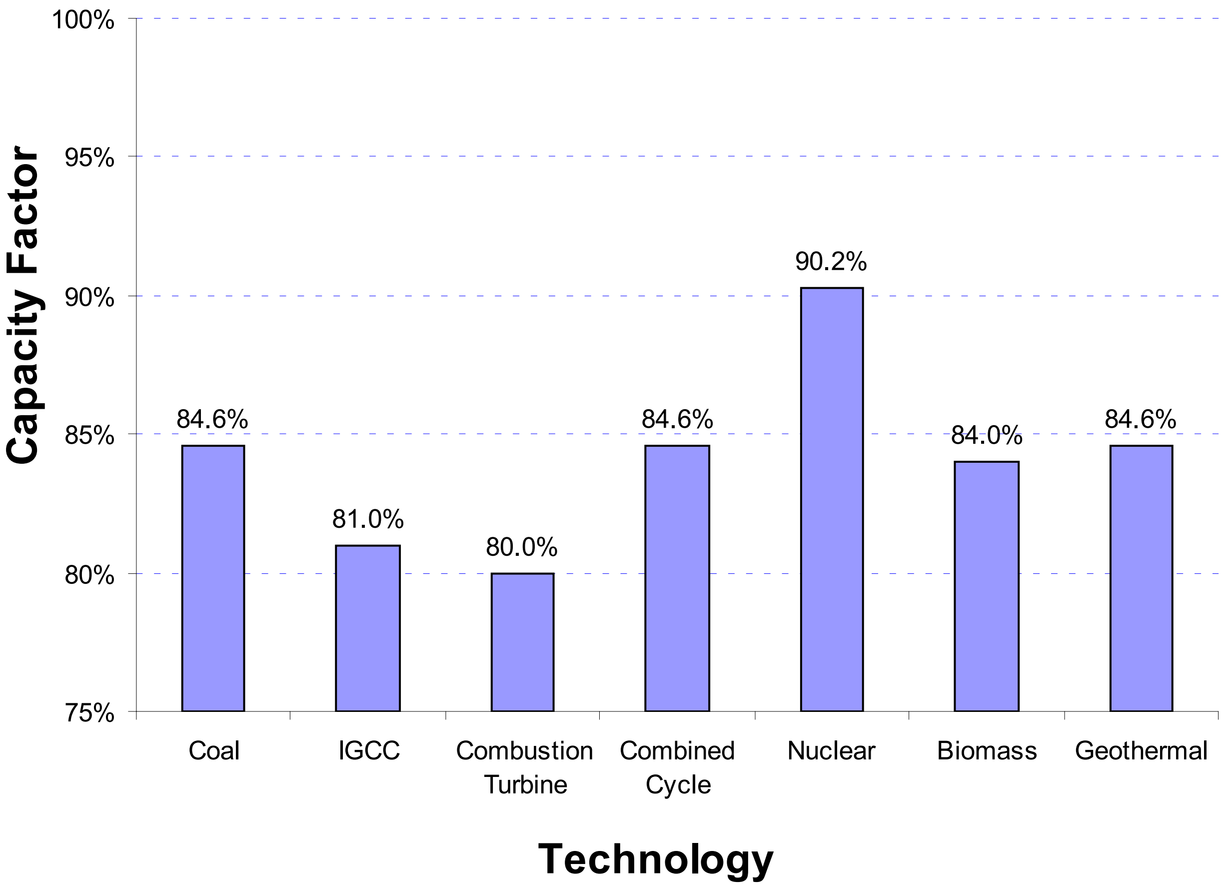


Figure 100. NREL-SEAC 2008, capacity factors, seven technologies

Plant Lifetime

Plant life does not improve over time for any technology in this data set. Also, plant life is the same between NREL-SEAC 2008, as seen in Figure 101.

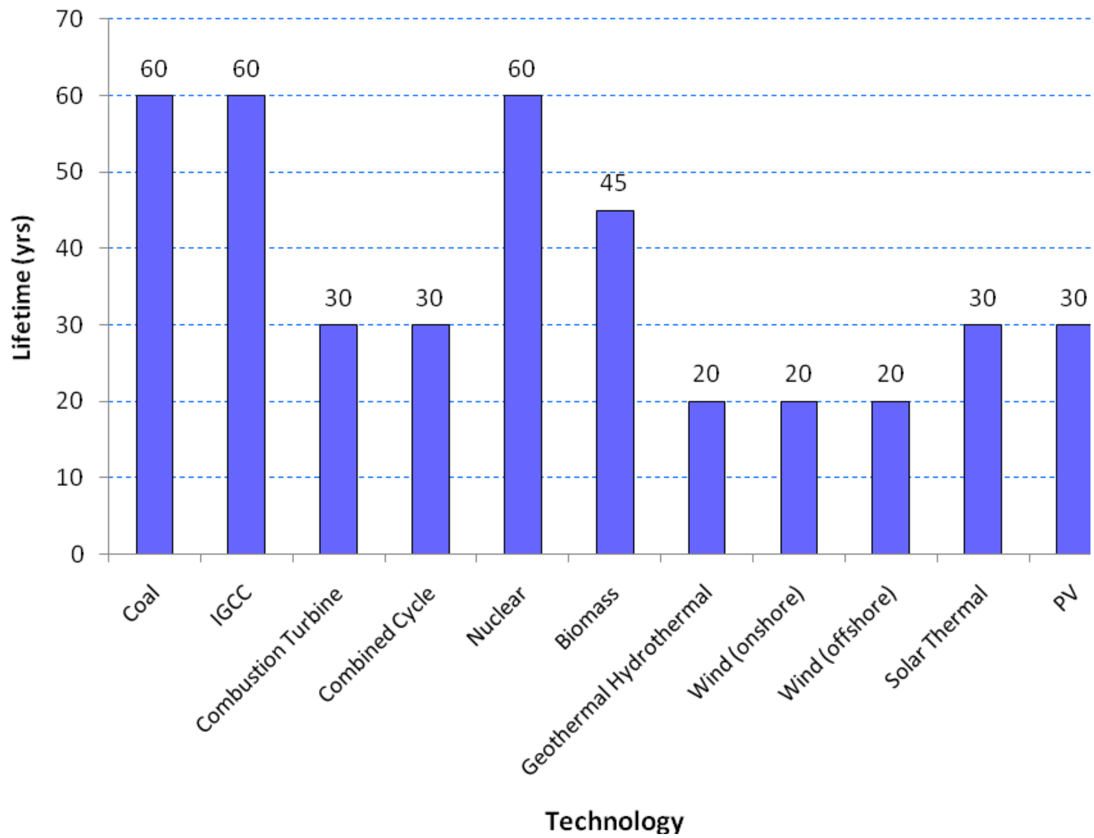


Figure 101. NREL-SEAC 2008, plant lifetime for 11 technologies

5.1.6 Cost Characteristics

The NREL-SEAC cost characteristics were developed with assistance from Black & Veatch (B&V) using a three step process.[46] First, B&V started with in-house data for projects that had actually been built in recent years. Second, B&V consulted government (e.g., DOE) and industry experts, and requested opinions on current as well as projected costs. Third, B&V used engineering judgment, coupled with the information developed during the first two steps, to develop a set of projected cost characteristics for individual power generation technologies.

The cost development process applies to overnight capital costs as well as O&M costs. In the case of overnight capital costs, B&V did not rely on learning curves. Rather, changes in overnight capital costs over time are based on engineering judgment coupled with data from actual projects and input from industry experts. In addition to not using learning curves, B&V also reported that commodity price indices are not used to develop cost projections.[47]

Overnight Capital Costs

The following three tables and three figures compare overnight capital costs for 11 technologies in the NREL-SEAC 2008 data set.

[46] Conversation between J. Macknick (NREL) and J. Pietruszkiewicz (B&V), February 2010.
[47] Ibid.

In Table 34, capital costs provided by NREL are shown for all wind and solar thermal technologies and classes. In all cases, capital costs were identical for the various classes within wind and solar thermal technologies.

Table 34. NREL-SEAC 2008, Overnight Capital Cost for Wind Technologies (2004$/kW)

Year	Deep Offshore Class 3-7	Shallow Offshore Class 3-7	Onshore Wind Class 3-7	Solar Thermal Class 1-5
2000	3,046	3,046	1,570	5,850
2005	3,046	3,046	1,570	5,850
2010	3,046	3,046	1,570	5,572
2015	3,046	3,046	1,530	4,179
2020	2,665	2,665	1,490	4,179
2025	2,570	2,570	1,451	4,179
2030	2,475	2,475	1,413	4,179
2035	2,380	2,380	1,413	4,179
2040	2,284	2,284	1,413	4,179
2045	2,284	2,284	1,413	4,179
2050	2,284	2,284	1,413	4,179

Table 35 shows the overnight capital costs for geothermal, PV, and biomass technologies. For the geothermal hydrothermal data in the NREL-SEAC data set, capital costs and O&M costs for all geo classes and regions are static throughout the modeling horizon (2000-2050). Geothermal cost data from the various geo classes and regions were aggregated to reflect typical geothermal plants. The aggregation methodology involved sorting geothermal plants by cost. At the point where the cost points diverged from the linear trend, the data were cut off. The points not cut off from the data are considered to be the most plausible sites for development. The average capital costs and fixed costs from these sites were used in this report and accompanying database. Capital costs for geothermal hydrothermal are constant at $2,818 per kilowatt.

Table 35. NREL-SEAC 2008, Overnight Capital Cost for Geothermal and PV (2004$/kW)

Year	Geothermal	PV	Biomass
2000	2,818	5,000	2,617
2005	2,818	5,000	2,617
2010	2,818	3,480	2,617
2015	2,818	2,538	2,617
2020	2,818	2,100	2,617
2025	2,818	1,705	2,617
2030	2,818	1,512	2,617
2035	2,818	1,493	2,617
2040	2,818	1,474	2,617
2045	2,818	1,455	2,617
2050	2,818	1,436	2,617

The same data given by NREL on overnight capital costs for renewable technologies in NREL-SEAC is shown in Figure 102. Costs have been linearly interpolated to allow comparisons across years without NREL data.

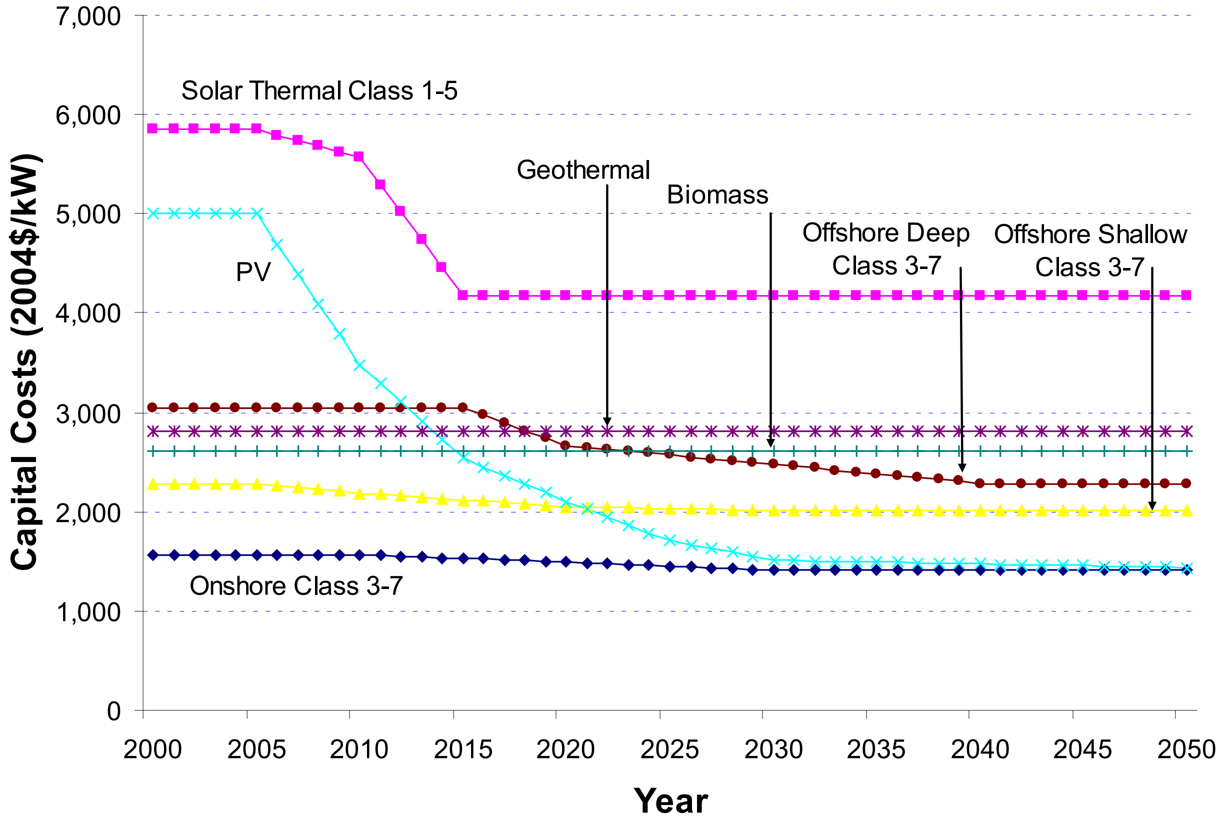


Figure 102. NREL-SEAC 2008, overnight capital cost for renewable technologies

The NREL-SEAC 2008 capital cost parameters provided by NREL are summarized for the five conventional technologies in Table 36 and shown Figure 103. In most cases, base overnight capital costs are adjusted over the modeling horizon (2000 through 2050).

Table 36. NREL-SEAC 2008, Overnight Capital Cost for Five Technologies (2004$/kW)

Year	Comb Turbine	Comb Cycle	IGCC	Coal	Nuclear
2000	595	742	2,617	2,018	3,103
2005	595	742	2,617	2,018	3,103
2010	714	742	2,703	2,075	3,016
2015	714	742	2,703	2,132	3,016
2020	714	742	2,703	2,132	2,874
2025	714	742	2,703	2,132	2,874
2030	714	742	2,703	2,132	2,801
2035	714	742	2,703	2,132	2,801

Year	Comb Turbine	Comb Cycle	IGCC	Coal	Nuclear
2040	714	742	2,703	2,132	2,801
2045	714	742	2,703	2,132	2,801
2050	714	742	2,703	2,132	2,801

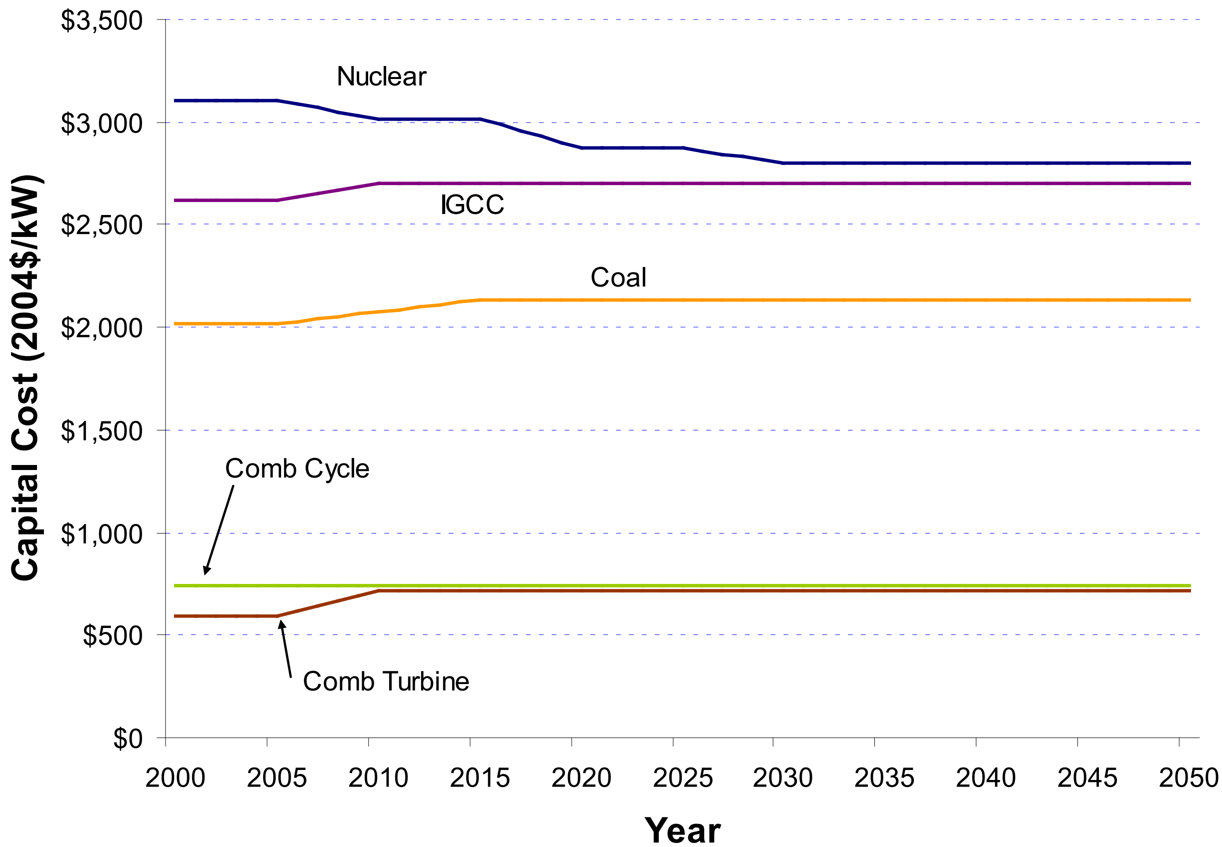


Figure 103. NREL-SEAC 2008, overnight capital cost for five technologies

Comparing Figure 102 and Figure 103, the highest capital cost between all 11 technologies is solar CSP. By the end of the modeling horizon, solar CSP decreases significantly, by nearly 30 percent, but it is still the highest. The capital cost for geothermal hydrothermal is constant across geo classes and regions over the modeling horizon. Although conventional combustion turbine technology increases in cost during the modeling period, it remains the lowest overnight cost throughout the period.

Learning

Overnight capital costs change over time for some technologies in the NREL-SEAC data set. While these changes are not based on learning rates within the NREL-SEAC model, effective learning rates can be calculated for the 2008 NREL-SEAC data set based on reported capital costs using the following simple formula:

$$\textbf{\textit{Learning Factor}} = \frac{\textbf{\textit{Future Year Capital Cost}}}{\textbf{\textit{Starting Year Capital Cost}}}$$

All NREL-SEAC technologies begin with data in the year 2000. The *future year capital cost* is the year in which the learning factor is calculated. Figure 104 shows the learning factors for all renewable technologies.

Figure 105 shows learning factors for five conventional technologies. This figure shows that some technologies are expected to increase in cost over time.

Geothermal, combined cycle, and biomass technologies have a learning factor of one because they had no change in capital costs. These series are all indicated in the chart as part of the bold black line.

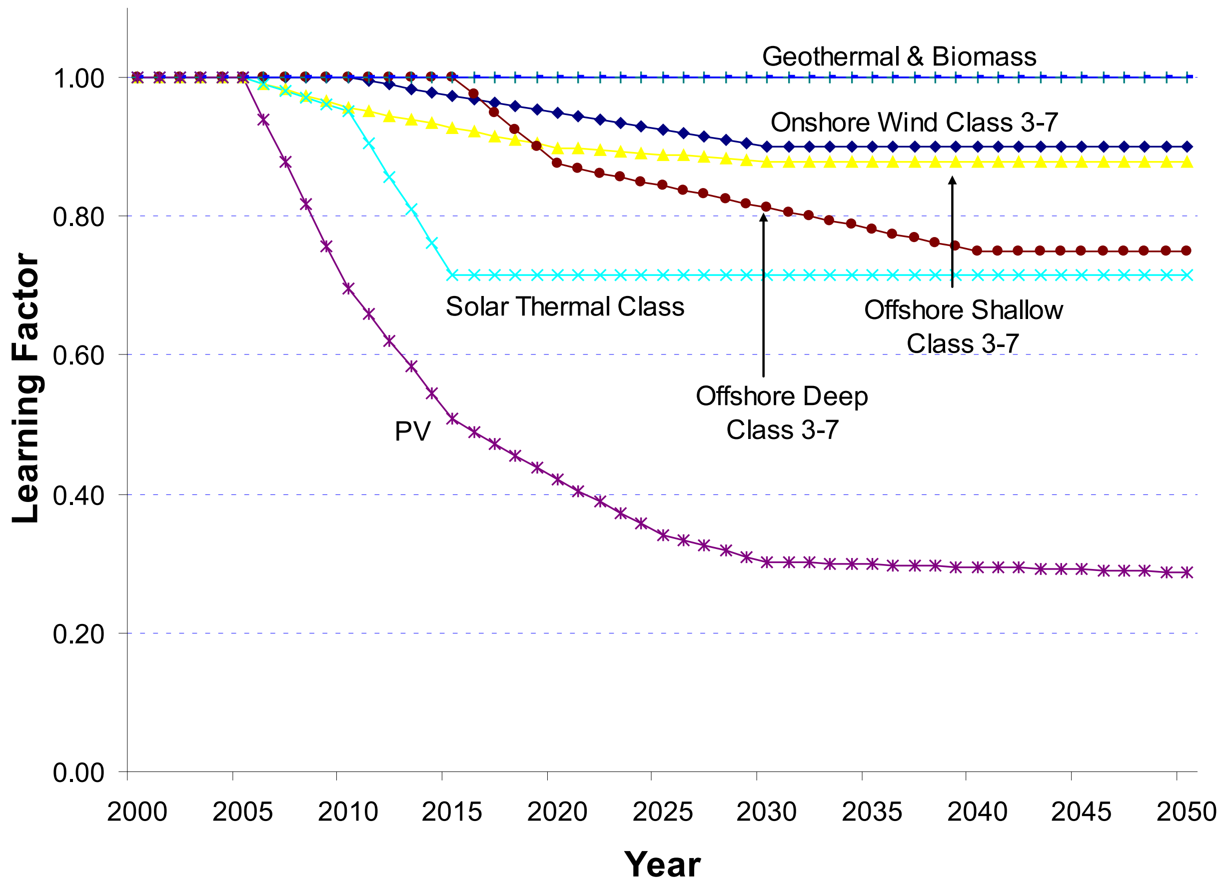


Figure 104. NREL-SEAC 2008, learning factor for renewable technologies

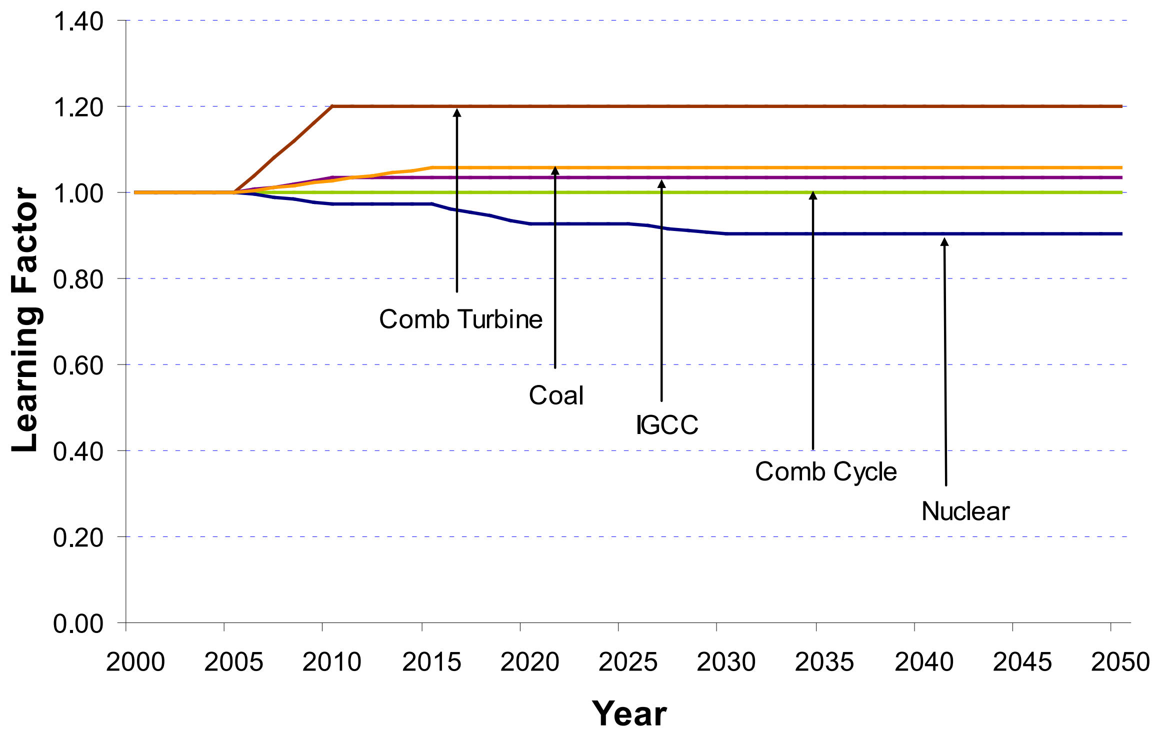


Figure 105. NREL-SEAC 2008, learning factors for five conventional technologies

O&M Costs

Table 37 shows the fixed O&M costs for some of the technologies with changing costs. Fixed O&M costs changed over time for solar thermal, PV, combustion turbines, CAES, and batteries in NREL-SEAC 2008. Wind and offshore wind technologies have different fixed costs but maintain those costs throughout the modeling period. Fixed O&M costs for geothermal hydrothermal and geothermal EGS are not expected to change over time.

Table 37. NREL-SEAC, Fixed O&M Costs (2004$/kW/yr)

Year	Comb Turbine	PV	Solar Thermal
2000	7.33	70.00	55.72
2005	7.33	70.00	55.72
2010	6.28	22.00	51.07
2015	6.28	9.06	44.57
2020	6.28	7.50	44.57
2025	6.28	6.09	44.57
2030	6.28	5.40	44.57
2035	6.28	5.33	44.57
2040	6.28	5.27	44.57
2045	6.28	5.20	44.57
2050	6.28	5.13	44.57

Figure 106 shows fixed O&M costs for the same technologies listed in Table 37 with costs that have been linearly interpolated to allow comparisons between technology costs for gap years.

Figure 107 shows fixed O&M costs for technologies with constant costs. Geothermal has the highest fixed O&M cost. In NREL-SEAC 2008, combustion turbine is the technology with the lowest fixed O&M, but by 2025, PV is essentially tied with combustion turbines for the technology with the lowest fixed O&M cost.

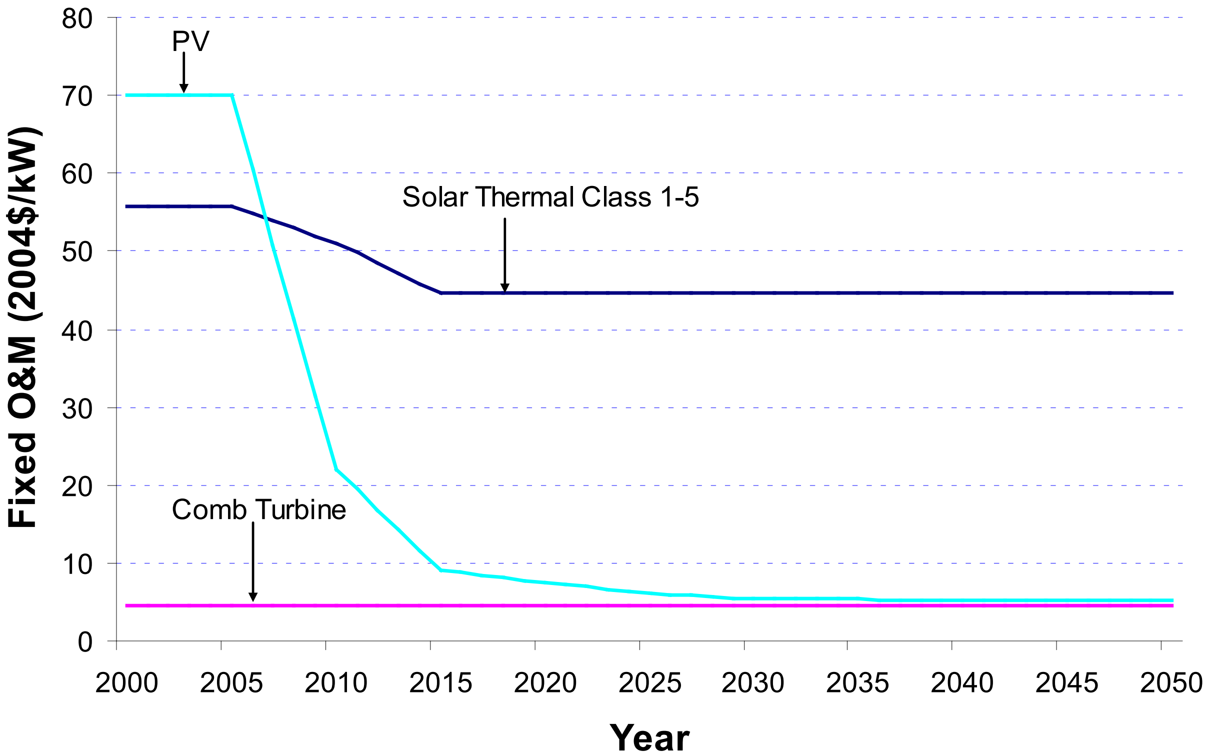


Figure 106. NREL-SEAC 2008, fixed O&M costs

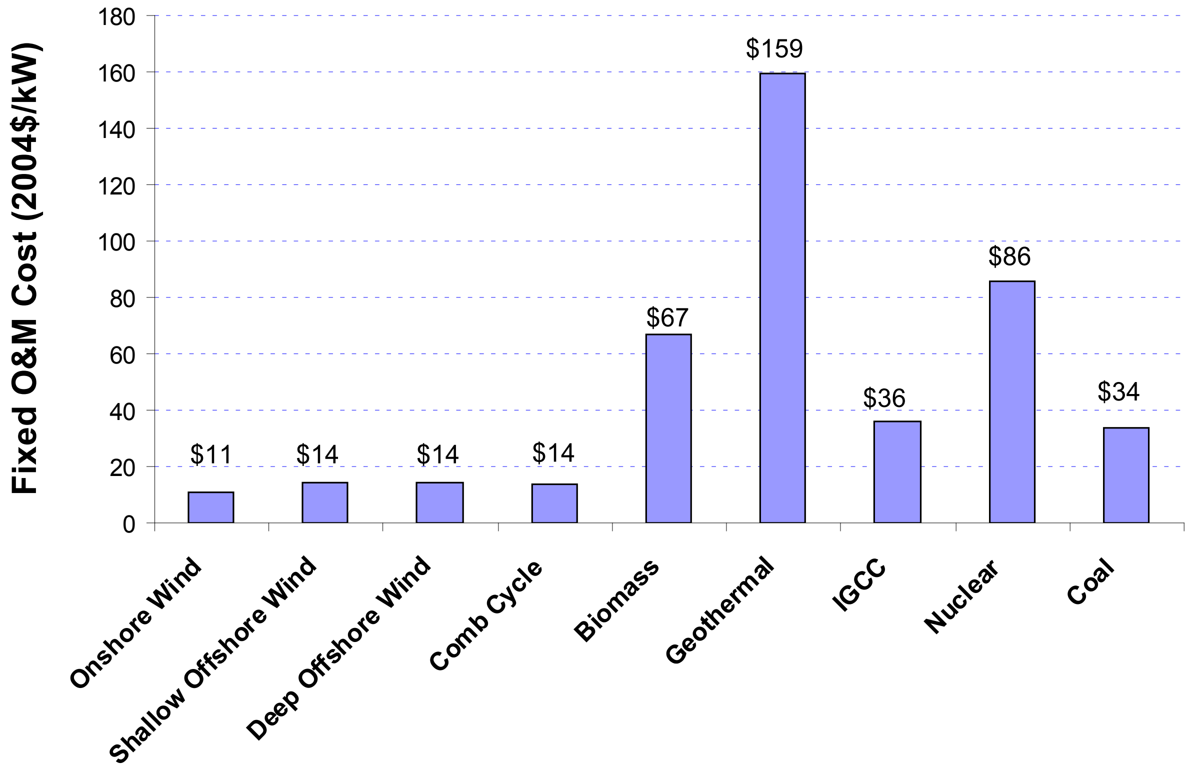


Figure 107. NREL-SEAC 2008, fixed O&M costs

Table 38 shows variable O&M costs for four technologies that having changing costs (3 wind technologies and combustion turbines).

Table 38. NREL-SEAC Variable O&M (2004$/MWh)

Year	Wind Class 3-7	Shallow Class 3-7	Deep Class 3	Comb Turbine
2000	6.66	19.99	22.84	11.42
2005	6.66	19.99	22.84	11.42
2010	5.19	17.13	22.84	2.67
2015	4.76	15.23	22.84	2.67
2020	4.41	13.33	19.99	2.67
2025	4.28	11.90	17.61	2.67
2030	4.16	10.47	15.23	2.67
2035	4.16	10.47	14.28	2.67
2040	4.16	10.47	13.33	2.67
2045	4.16	10.47	13.33	2.67
2050	4.16	10.47	13.33	2.67

Figure 108 shows variable O&M costs for the same four technologies found in Table 38 with linearly interpolated values for gap years to make relative comparisons between technology costs. Deep offshore wind has the highest variable O&M cost in the NREL-SEAC 2008 data set.

Variable O&M costs in the NREL-SEAC 2008 data set do not change over time for CSP, PV, hydro, landfill, biomass, nuclear, combined cycle, combined cycle with CCS, new coal, IGCC, coal with CCS, new cofired, and pumped hydro. Figure 109 compares variable O&M costs for six technologies in NREL-SEAC 2008 with constant costs. In NREL-SEAC 2008, PV and geothermal technologies do not have variable O&M costs.

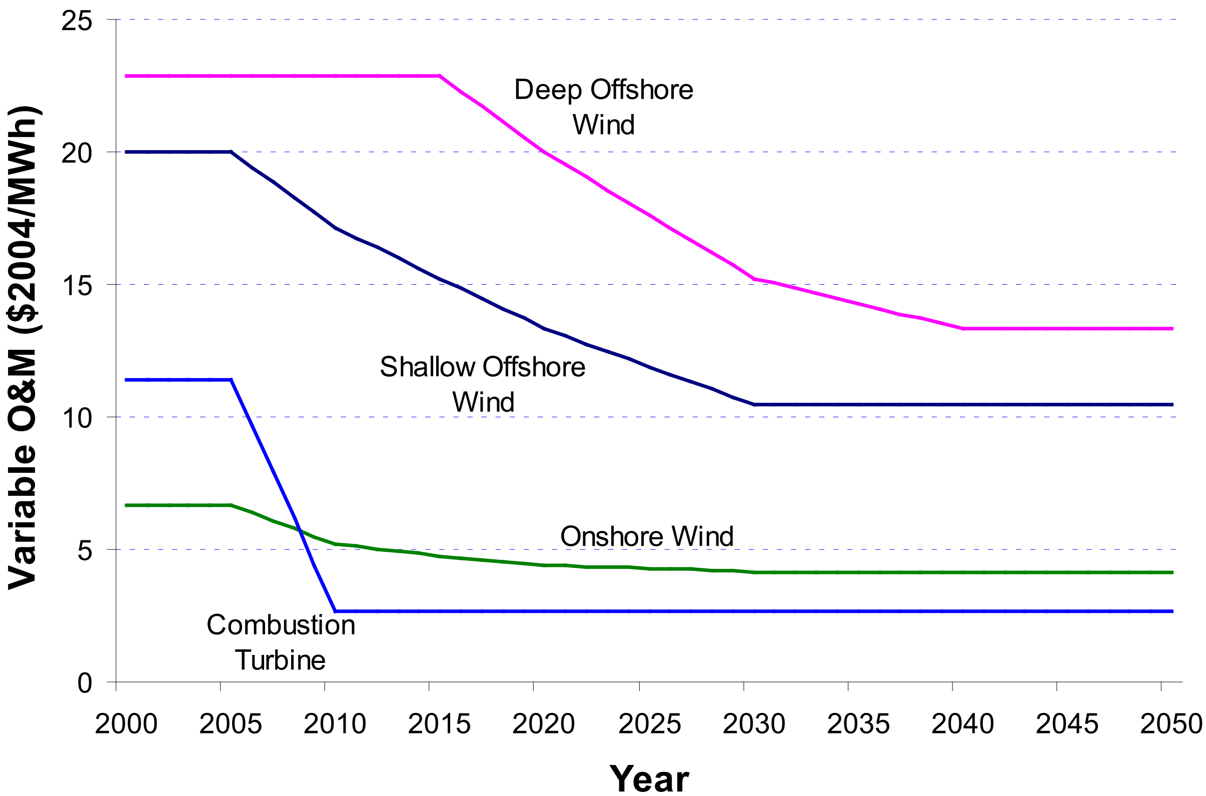


Figure 108. NREL-SEAC 2008, variable O&M costs

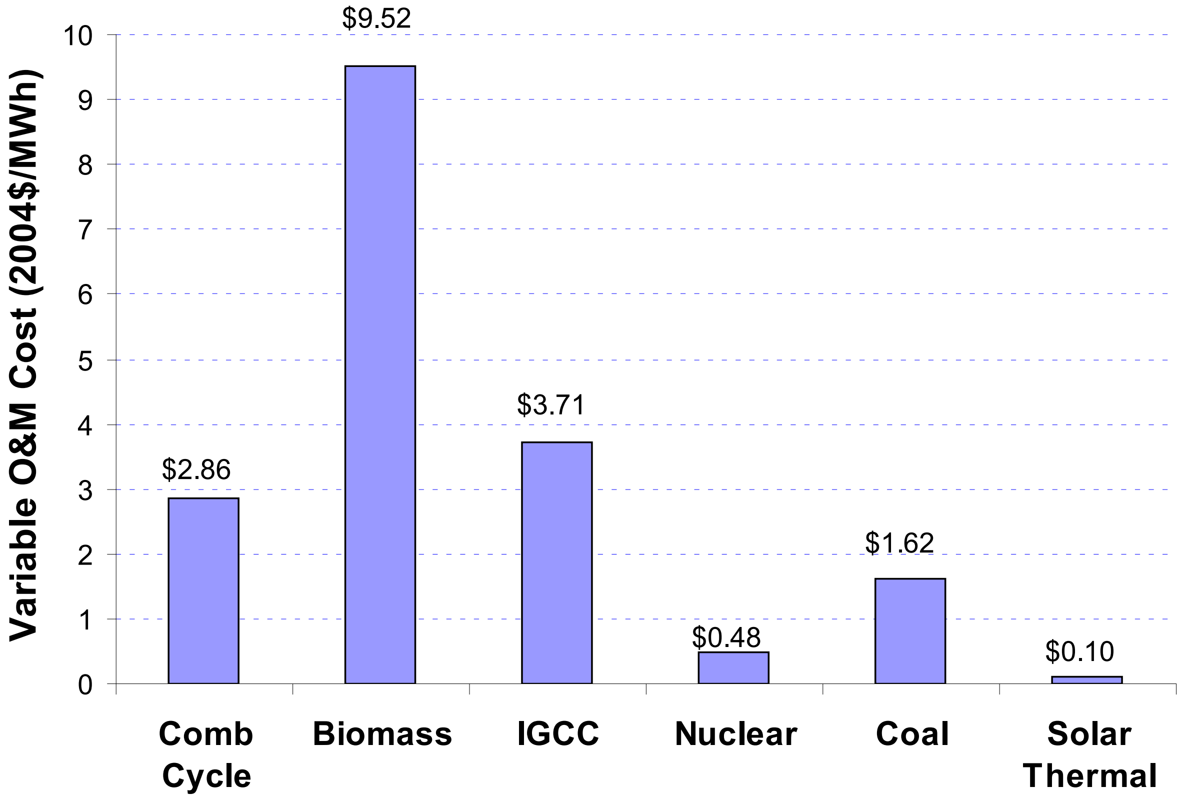


Figure 109. NREL-SEAC 2008 variable O&M cost for technologies with constant costs

Appendix D. MiniCAM (MiniCAM 2008 Data Set)

The MiniCAM modeling framework was developed by Pacific Northwest National Laboratory (PNNL), and PNNL maintains the power plant technology files that support this model. For this project, NREL obtained a MiniCAM data set from PNNL, and provided this data set to ICF.

The cost assumptions and efficiencies for the power plant technologies used in MiniCAM are generally consistent with the 2008 Annual Energy Outlook.[48] However, there are differences. For example, in the MiniCAM data set the geothermal characteristics were adjusted based on information in addition to the AEO 2008 report.[49] Costs for solar and wind technologies were altered based on GIS data.

ICF contacted PNNL to determine if there are plans to update the power plant characteristics in MiniCAM, which are now based on AEO 2008 data, with AEO 2009 values.[50] PNNL responded that they are aware that power generation capital costs have risen substantially since the AEO 2008 report was released due to commodity price increases and other factors. However, PNNL reported that they have no current plans to update power plant costs in MiniCAM.

The data set obtained for the MiniCAM model has cost and performance characteristics for 12 electricity generation technologies (see Table 39).[51] This data set has power plant characteristics in 15 year increments extending over a 45 year time period from 2005 through 2050. The key characteristics of the MiniCAM data set are described in this section, which is organized as follows:

- Technical Performance Characteristics
    - Plant Size
    - Heat Rate
    - Capacity Factor
    - Plant Lifetime
- Cost Characteristics
    - Overnight Capital Costs
    - Learning
    - O&M Costs

---

[48] CO_2 Emission Mitigation and Technological Advance: An Updated Analysis of Advance Technology Scenarios, PNNL, PNNL-18075, December 2008, p 3.9.
[49] CO_2 Emission Mitigation and Technological Advance: An Updated Analysis of Advance Technology Scenarios, PNNL, PNNL-18075, December 2008, p 3.14.
[50] E-mail exchange, November 10 and 11, 2009.
[51] In addition to the 12 technologies described, the MiniCAM data set included a 13th technology for an oil-fired turbine. However, this technology is not discussed in this report because it is expected to have limited market penetration in future years.

5.1.7 Technical Performance Characteristics

Plant Size

Power plant name plate capacities for 10 of the 12 MiniCAM technologies are shown in Figure 110. These 10 technologies represent all of the MiniCAM renewable technologies and all of the MiniCAM fossil technologies with the exception of those fossil technologies that are expected to come online in future years with carbon capture capabilities. As indicated, the capacities range from 5 MW for PV to 1,350 MW for nuclear.

The MiniCAM capacities match the capacities used in the AEO 2008 report, which is to be expected since the source for much of the MiniCAM data is the AEO 2008 report. The power plant capacities did not change for most technologies between the AEO 2008 report and the AEO 2009 report. Therefore, the power plant capacities for MiniCAM shown in Figure 110 generally match the power capacities for the AEO 2009 data set shown in Figure 71. One difference is that the MiniCAM data set only has conventional combustion turbine and combined cycle technologies, while the AEO 2009 data set has both conventional and advanced technologies (advanced technologies are shown in Figure 71).

Table 39. MiniCAM, Cost and Performance Characteristics

Technology	Online Year	Size (MW)	Overnight Capital Cost (2004 $/kW)	O&M (2004$) Variable ($/MWh)	O&M (2004$) Fixed ($/kW/yr)	Heat Rate (Btu/kWh)	Capacity Factor (%)	Life (yrs)
Coal, scrubbed	2005	600	1,545	4.58	27.50	9,319	80%	45
IGCC	2020	550	1,791	2.92	38.62	8,005	80%	45
IGCC, with carbon storage	2020	380	3,301	11.82	52.44	9,367	80%	45
Combustion Turbine, conventional	2005	160	492	3.36	11.31	8,877	10%	45
Combined Cycle, conventional	2005	250	725	2.03	12.07	6,164	80%	45
Combined Cycle, with carbon capture	2020	400	2,551	8.95	15.24	6,950	80%	45
Nuclear	2005	1,350	2,300	1.80	64.00	10,339	90%	60
Biomass	2005	80	1,899	4.65	33.60	12,133	80%	45
Geothermal	2005	50	2,419	0.00	78.74	34,120	90%	30
Wind (onshore)	2005	50	1,167	7.00	11.50	---	40%	30
Solar Thermal (CSP)	2020	100	3,731	0.00	34.37	---	73%	30
PV	2005	5	9,500	0.00	100.00	---	25%	30

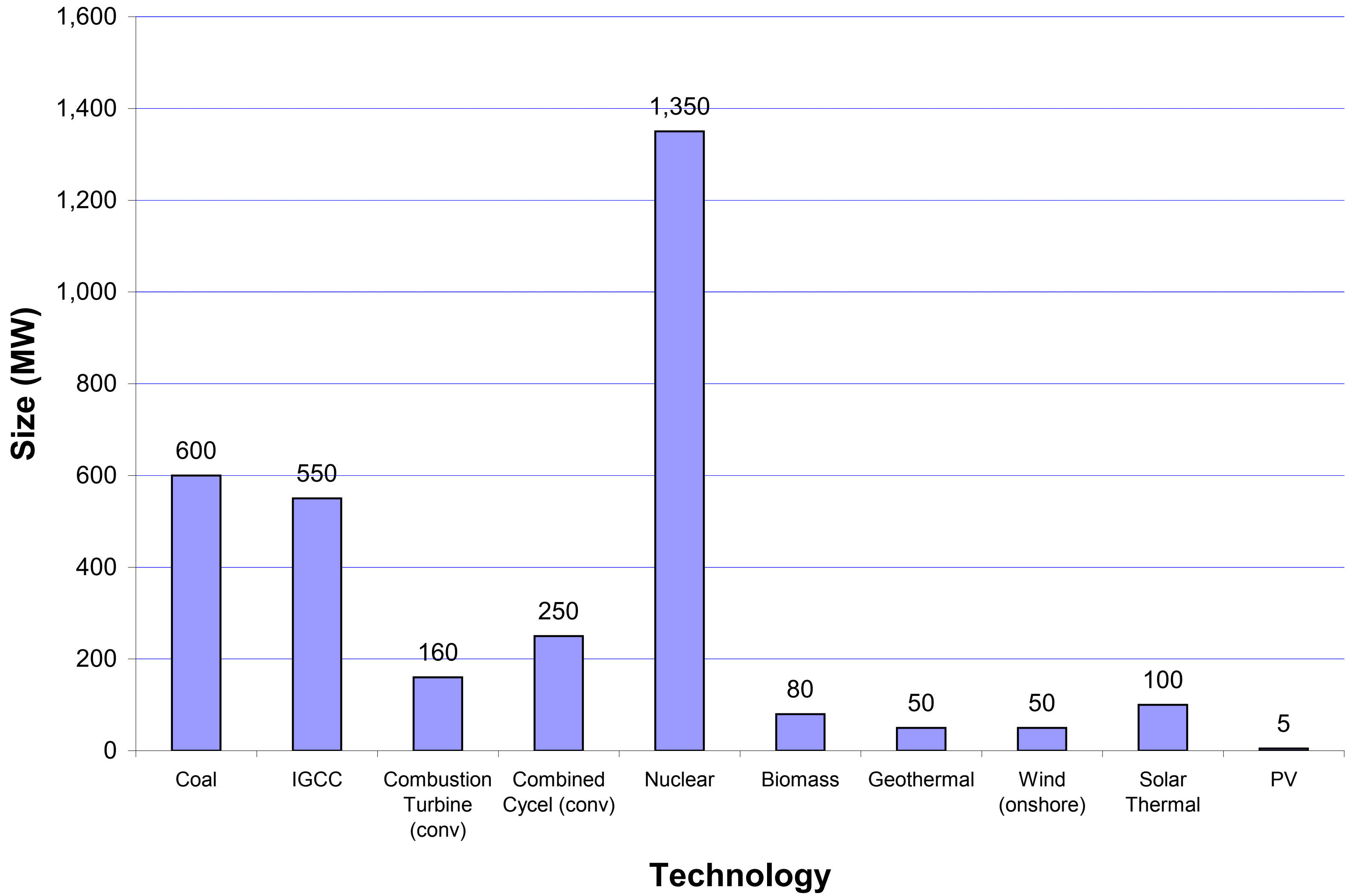


Figure 110. MiniCAM, plant size

Heat Rate

In the MiniCAM data, heat rates for fossil and nuclear power plants show improvement over time. The heat rates for fossil and nuclear technologies for the time period of 2005 through 2050 are shown in Table 40 and Figure 111. The table also shows heat rate values for geothermal technologies. In the MiniCAM data set, geothermal technologies have a constant heat rate of 34,120 Btu/kWh (10% thermal efficiency) over the entire modeling horizon.

Table 40. MiniCAM, Heat Rates

	Heat Rate by Year (Btu/kWh)			
Technology	**2005**	**2020**	**2035**	**2050**
Coal, scrubbed	9,319	8,719	8,525	8,336
IGCC	---	8,005	7,598	7,266
Combustion Turbine, conventional	8,877	8,877	8,680	8,487
Combined Cycle, conventional	6,164	6,164	5,698	5,334
Nuclear	10,339	10,035	10,035	10,035
Biomass	12,133	8,939	8,740	8,546
Geothermal	34,120	34,120	34,120	34,120
Wind (onshore)	---	---	---	---
Solar Thermal (CSP)	---	---	---	---
PV	---	---	---	---

Capacity Factors

The MiniCAM capacity factors remain constant over the modeling horizon (to 2050) for all technologies with the exception of onshore wind. For onshore wind, the capacity factor rises from 40% in 2005 to 49% in 2050. The capacity factor is relatively low for the combustion turbine (10%), because the MiniCAM model handles this technology as a peaking turbine. The capacity factors for 10 MiniCAM technologies are shown in Table 41 and Figure 114.

Table 41. MiniCAM, Capacity Factors

	Capacity Factor by Year (%)			
Technology	**2005**	**2020**	**2035**	**2050**
Coal, scrubbed	80%	80%	80%	80%
IGCC	---	80%	80%	80%
Combustion Turbine, conventional	10%	10%	10%	10%
Combined Cycle, conventional	80%	80%	80%	80%
Nuclear	90%	90%	90%	90%
Biomass	80%	80%	80%	80%
Geothermal	90%	90%	90%	90%
Wind (onshore)	40%	45%	47%	49%
Solar Thermal (CSP)	---	73%	73%	73%
PV	25%	25%	25%	25%

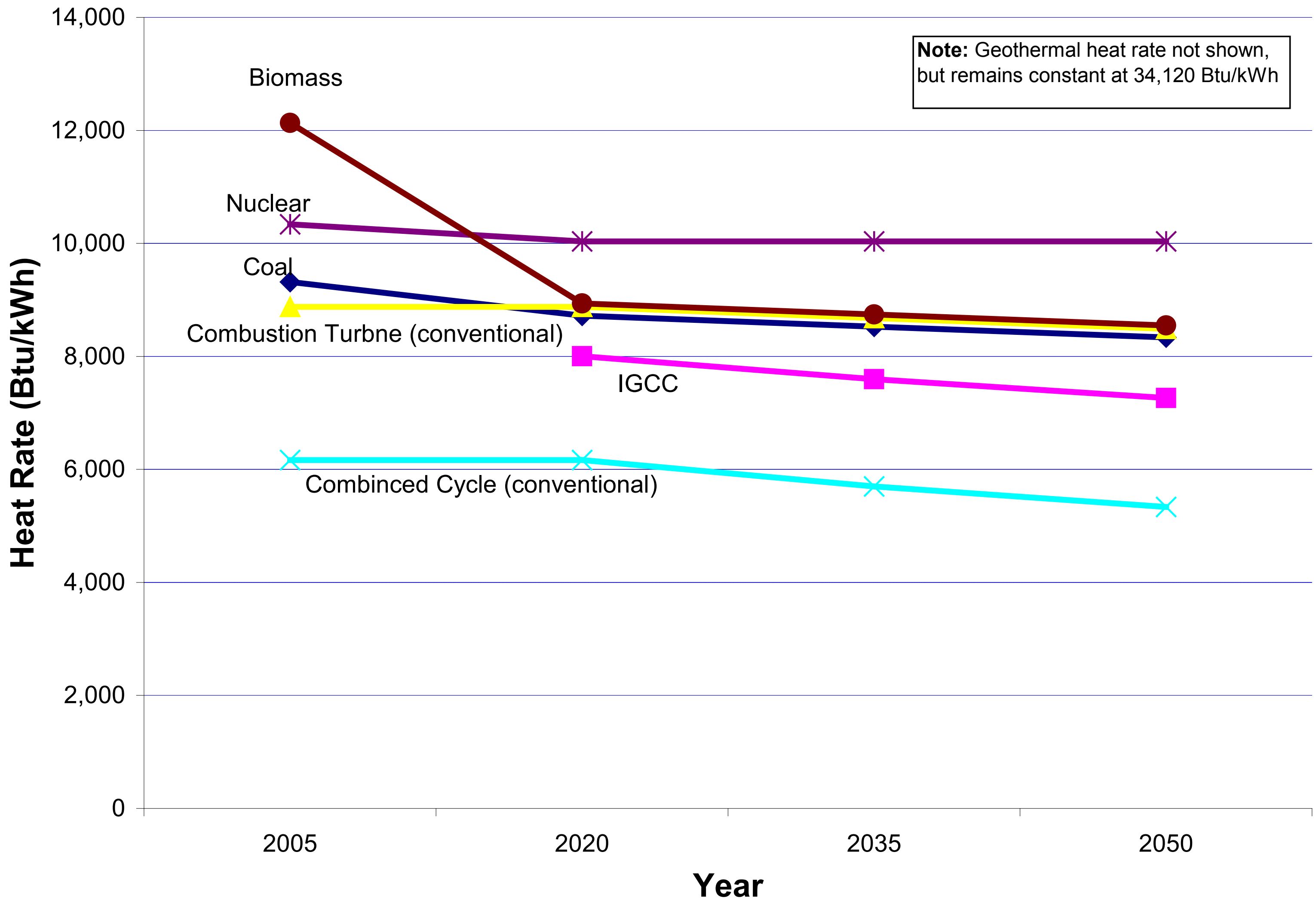


Figure 111. MiniCAM, heat rates for fossil and nuclear technologies

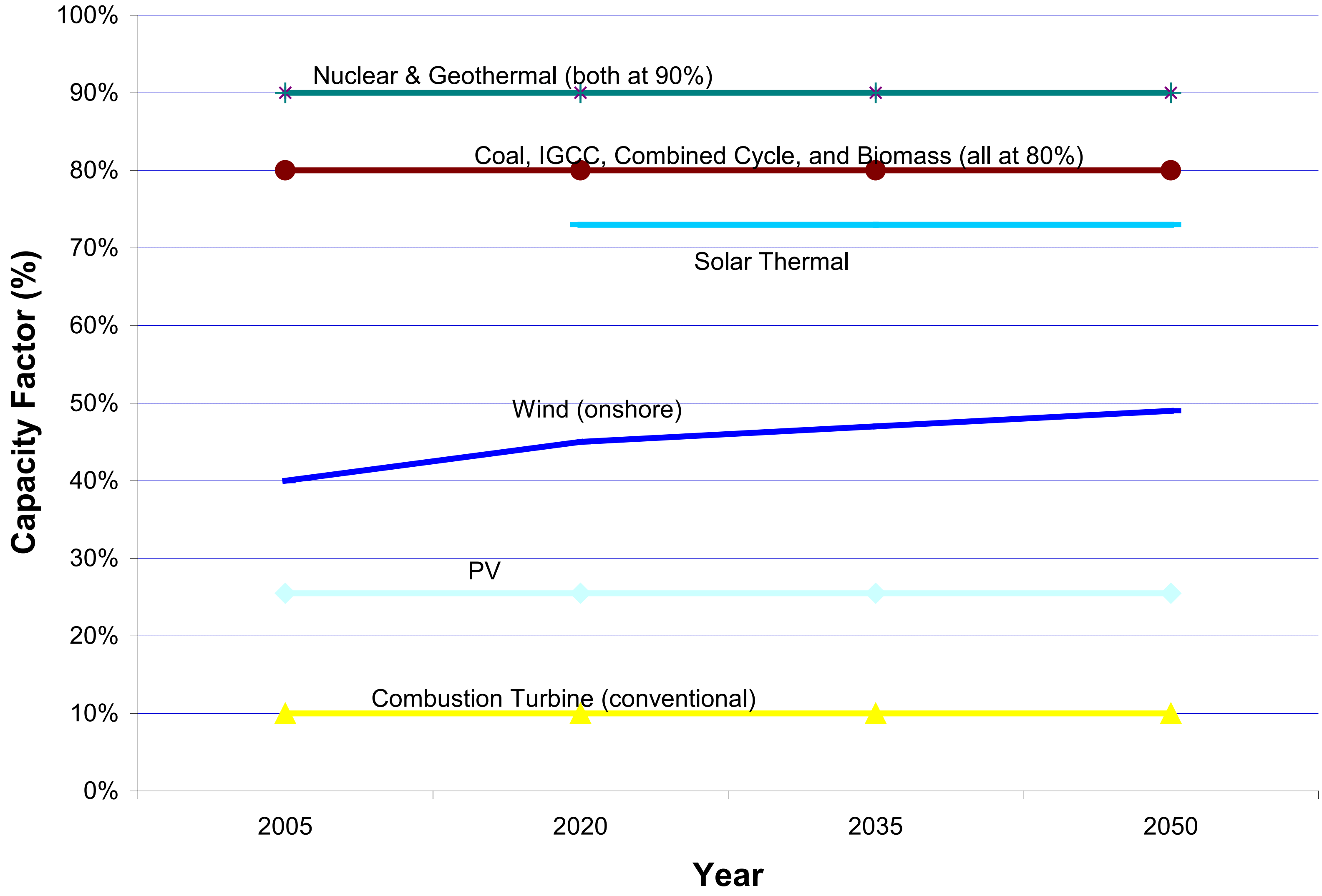


Figure 112. MiniCAM, capacity factors

Plant Lifetime

In the MiniCAM modeling, plant lifetime values ranging from 30 to 60 years are used for computing the levelized cost of energy. The lifetimes are shown in Figure 113.

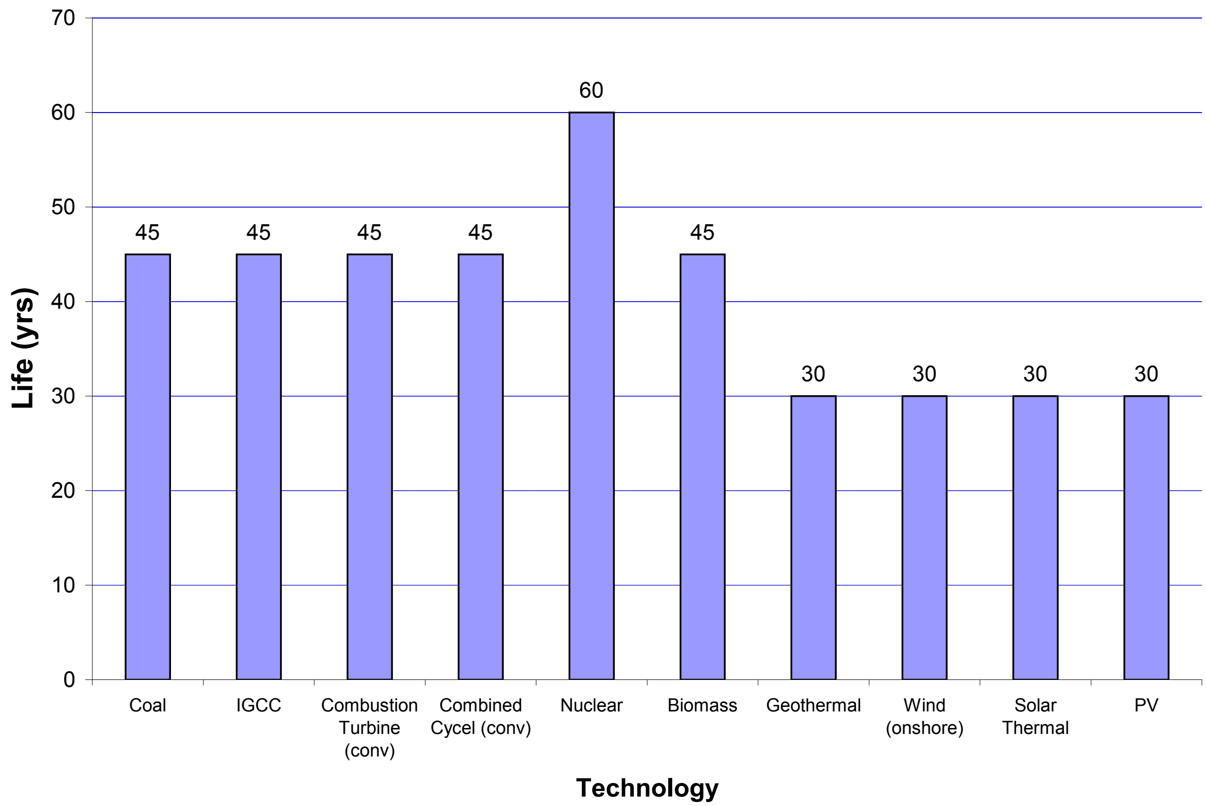


Figure 113. MiniCAM, power plant lifetime

5.1.8 Cost Characteristics

Capital Cost

Table 42 and Figure 114 show the overnight capital costs for 10 technologies in the MiniCAM data set. Similar to other models, PV technology has the highest cost and combustion turbine and combined cycle technologies are at the low end of the overnight capital cost range.

Table 42. MiniCAM, Capital Costs

	Overnight Capital Cost (2004$/kW)			
Technology	**2005**	**2020**	**2035**	**2050**
Coal, scrubbed	1,545	1,545	1,455	1,370
IGCC	---	1,791	1,610	1,361
Combustion Turbine, conventional	492	509	479	451
Combined Cycle, conventional	725	725	632	551
Nuclear	2,300	2,266	2,232	2,199
Biomass	1,899	1,899	1,789	1,684
Geothermal	2,419	2,419	2,220	2,082
Wind (onshore)	1,167	1,082	1,004	931
Solar Thermal (CSP)	---	3,731	3,209	2,976
PV	9,500	4,258	2,879	2,246

Learning

Learning is not explicitly modeled in MiniCAM. Rather, changes in technology characteristics, such as capital costs over time, are exogenously specified. Based on discussions with PNNL staff,[52] the exact process that leads to changes in capital costs is left ambiguous. Capital cost changes could result from government or private R&D (learning by R&D), or spillover effects from other industries.

[52] E-mail exchange between PNNL and ICF, January 4, 2010.

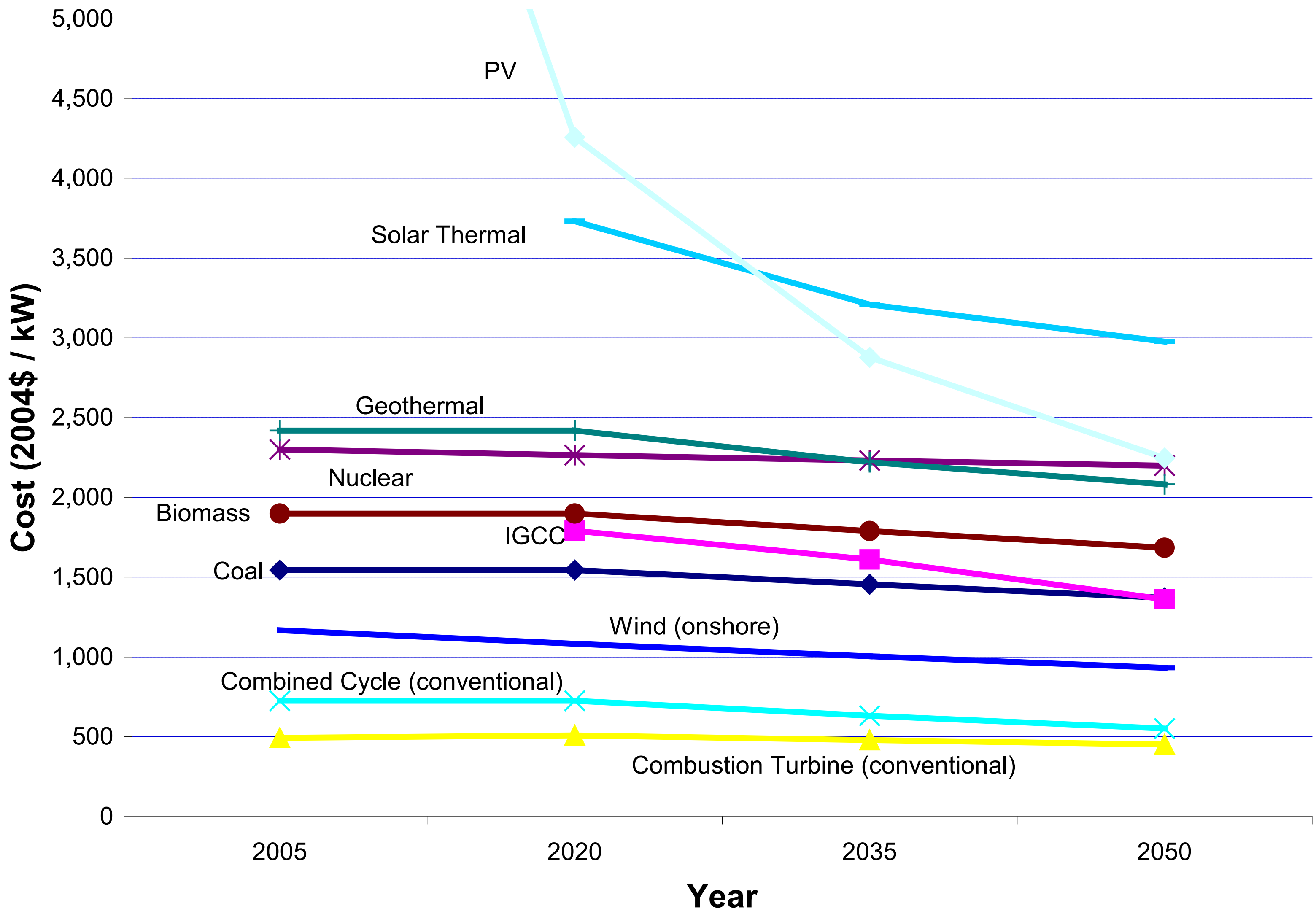


Figure 114. MiniCAM, capital costs

O&M

Fixed and variable O&M values for the MiniCAM data set are shown in Table 43. The fixed and variable O&M costs are graphed in Figure 115 and Figure 116, respectively.

Table 43. MiniCAM, Fixed and Variable O&M

	Fixed O&M (2004$/kW/yr)				Variable O&M (2004$/MWh)			
Technology	**2005**	**2020**	**2035**	**2050**	**2005**	**2020**	**2035**	**2050**
Coal, scrubbed	27.50	27.50	25.89	24.38	4.58	4.58	4.32	4.06
IGCC	---	38.62	36.02	32.44	---	2.92	2.72	2.45
Combustion Turbine, conventional	11.31	11.68	11.00	10.36	3.36	3.48	3.27	3.08
Combined Cycle, conventional	12.07	12.07	11.04	10.14	2.03	2.03	1.86	1.71
Nuclear	64.00	64.00	64.00	64.00	1.80	1.80	1.80	1.80
Biomass	33.60	33.60	31.64	29.79	4.65	4.65	4.38	4.12
Geothermal	78.74	78.74	72.25	67.75	0.00	0.00	0.00	0.00
Wind (onshore)	11.50	11.50	10.67	9.89	7.00	4.60	4.27	3.96
Solar Thermal (CSP)	---	34.37	29.56	27.42	---	0.00	0.00	0.00
PV	100.00	30.00	25.00	20.00	0.00	0.00	0.00	0.00

As indicated, PV is projected to have a sharp drop in fixed O&M costs, starting at $100 per kW per year in 2005, and then dropping to between $20 and $30 per kW per year for 2020 and beyond. All other technologies in the MiniCAM data set show a constant or slightly declining fixed O&M cost over the modeling horizon.

Variable O&M costs for geothermal, solar thermal, and PV are set at zero in the MiniCAM data set. Variable O&M costs for other technologies decline or remain constant over the modeling time period (**see** Figure 116). Onshore wind technologies have the largest decline in variable O&M, falling from $7 per MWh in 2005 to under $4 per MWh in 2050.

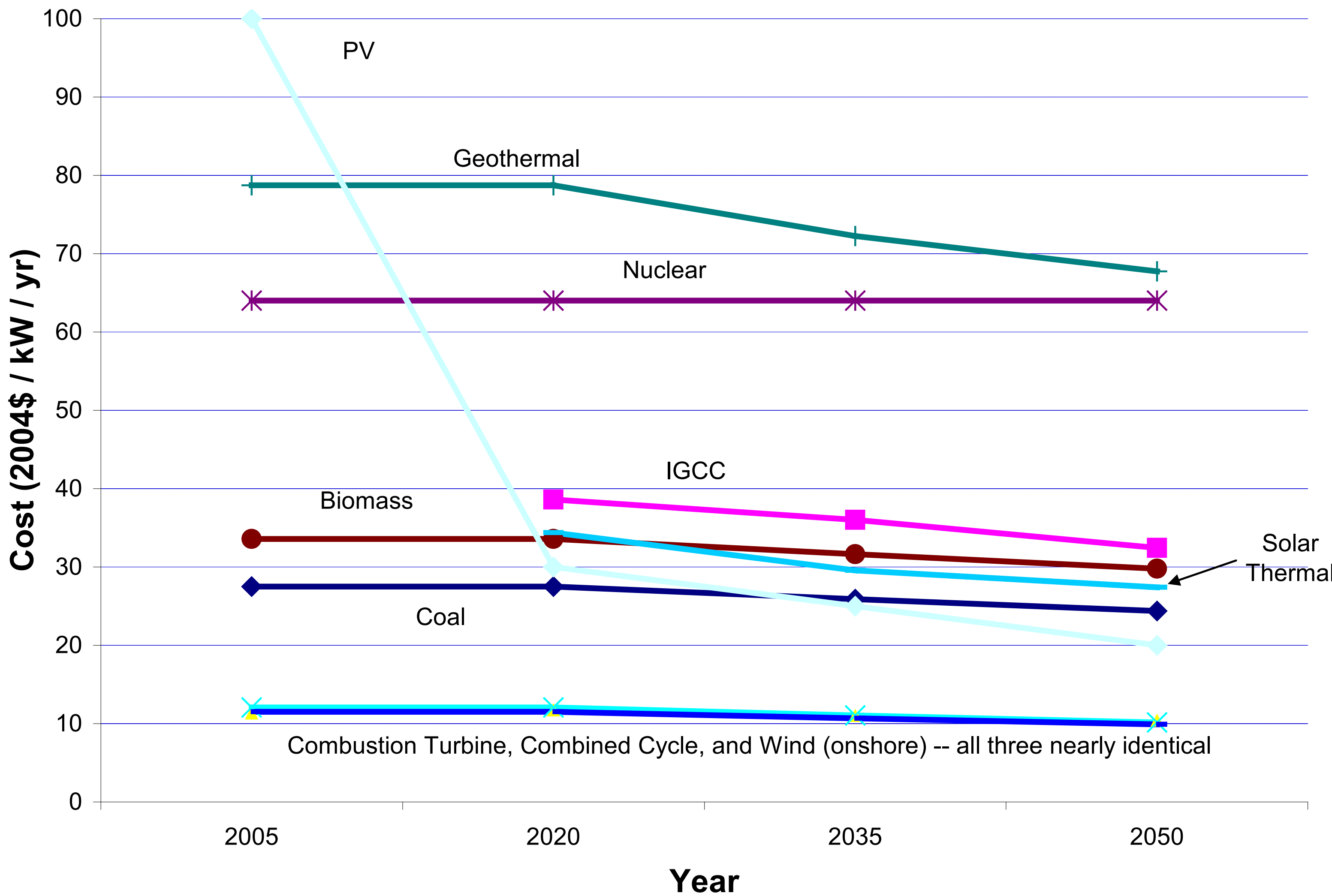


Figure 115. MiniCAM, fixed O&M costs

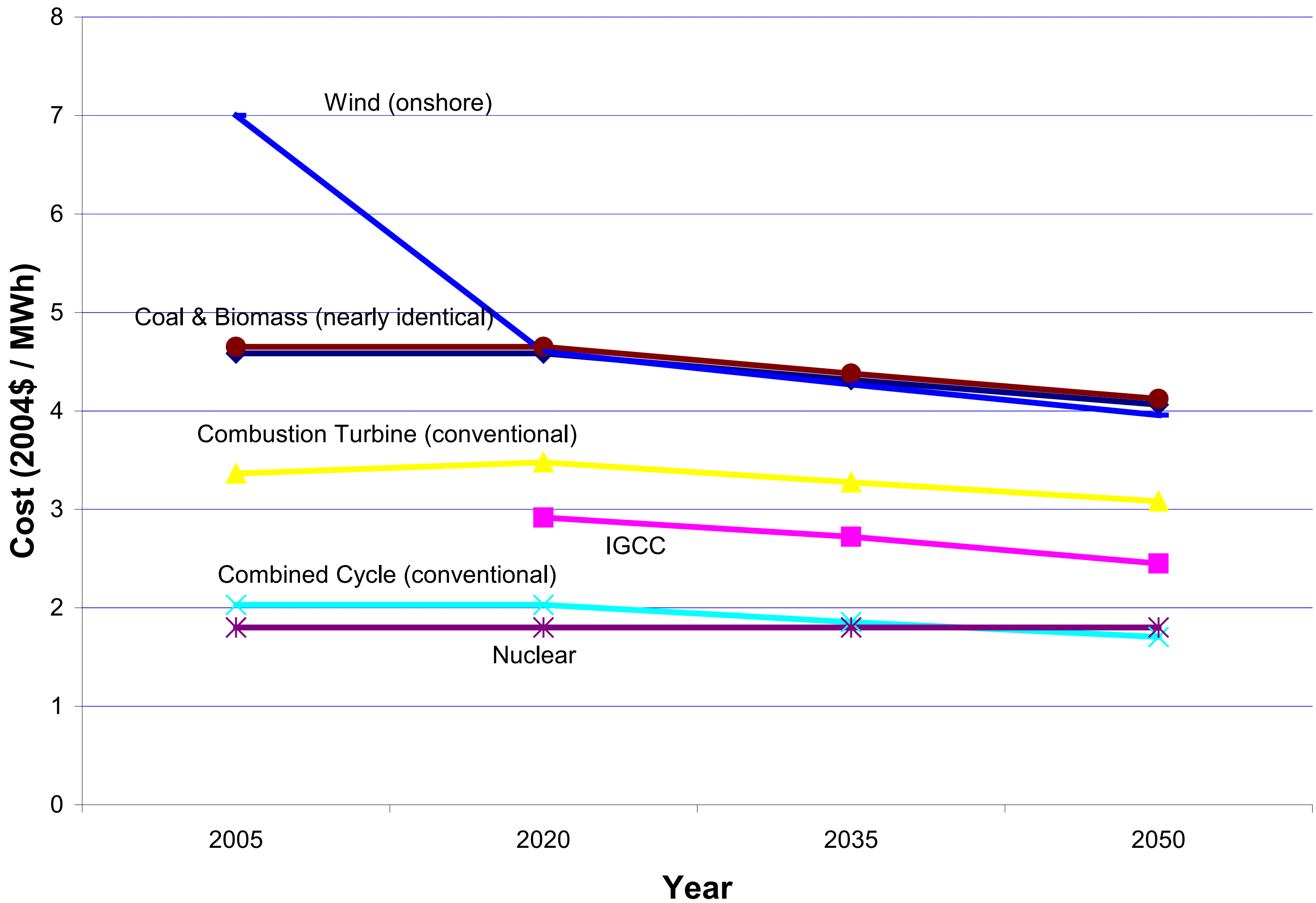


Figure 116. MiniCAM, variable O&M costs

Appendix E. IPM (EPA 2009 Data Set)

The IPM model, developed by ICF, has been used by many clients, including the U.S. Environmental Protection Agency (EPA). The EPA recently conducted an analysis with IPM in response to the 2009 American Recovery and Reinvestment Act (ARRA). The results of the EPA ARRA analysis are in the public domain, and for this project, the power generation technology characteristics used in this study were evaluated. The data set of power plant characteristics that corresponds to the EPA ARRA analysis is referred to as the EPA 2009 data set.

The power generation technology characteristics used in the EPA 2009 data set were taken from the AEO 2009 analysis. For the EPA 2009 data set, some adjustments were necessary to accommodate the IPM modeling structure, but these adjustments were, for the most part, minor. Other aspects of the EPA data set, such as carbon constraints, are significantly different compared to the AEO 2009 data set. However, this project is focused on power generation technologies, and in the case of power generation characteristics the EPA 2009 and AEO 2009 data sets are nearly identical.

Observations related to the technical performance and cost characteristics in the EPA 2009 data set are included in the remainder of this section, which is organized as follows:

- Technical Performance Characteristics
    - Plant Size
    - Online Year
    - Heat Rate
    - Capacity Factor
    - Plant Lifetime
- Cost Characteristics
    - Overnight Capital Costs
    - Learning
    - O&M Costs (fixed and variable)

5.1.9 Technical Performance Characteristics

The EPA data set has 13 technologies (compared to 20 for AEO 2009). These 13 technologies are shown in Table 44 , along with the online year, heat rate, and availability.

Plant Size

Plant sizes remain constant in all years. Table 44 shows plant sizes for all IPM technologies.

Online Year

As noted in Table 44 (and shown in Figure 117 for eight technologies), the online years range from 2012 to 2020. Because nuclear is based on advanced technology, it has the latest online year (2020).

Table 44. EPA 2009, Technical Data

Technology	Online Year	Heat Rate (Btu/kWh)	Capacity Factor (%)	Plant Size (MW)
Coal	2015	9,200	85%	600
Coal (with CCS)	2015	10,781	80%	380
IGCC	2015	8,765	85%	550
Combustion Turbine (adv)	2012	9,289	92%	230
Combined Cycle (adv)	2012	6,752	87%	400
Nuclear	2020	10,434	89%	1,350
Biomass	2012	9,646	83%	80
MSW, LFG	2012	13,648	90%	30
Fuel Cells	2012	7,930	87%	10
Wind (onshore)	2012	---	39%	50
PV	2012	---	24%	5
Solar Thermal	2012	---	36%	100
Geothermal	2012	---	87%	50

Heat Rate

One difference between the EPA 2009 and AEO 2009 data sets is that EPA 2009 uses constant heat rates over the modeling horizon (2009 through 2035), while AEO 2009 allows for improved heat rates over time. The constant value heat rates in EPA data set are shown in Table 44 and Figure 118 for eight common technologies.

Capacity Factor

The EPA data set uses availability factors for fossil fuel, biomass, and MSW/LFG power plants, which are a measure of a plant's mechanical integrity. Unlike capacity factors, availability factors do not account for resource availability. The availability factors for fossil fuel, biomass, and MSW/LFG power plants are shown in Table 44 and Figure 119 under the heading "capacity factor" and are all 80% or higher. The EPA data set uses capacity factors for nuclear, wind, and solar. Resource availability has a big impact on wind and solar. In all technologies, the capacity factor remains constant over the time horizon.

Plant Lifetime

EPA 2009 does not assume plant lifetimes for technology. Plants are retired based on economic optimization within the linear program. Furthermore, EPA 2009 has no degradation. A plant will run just as efficiently in the last year a plant is built in the model as it did in the first year it was built.

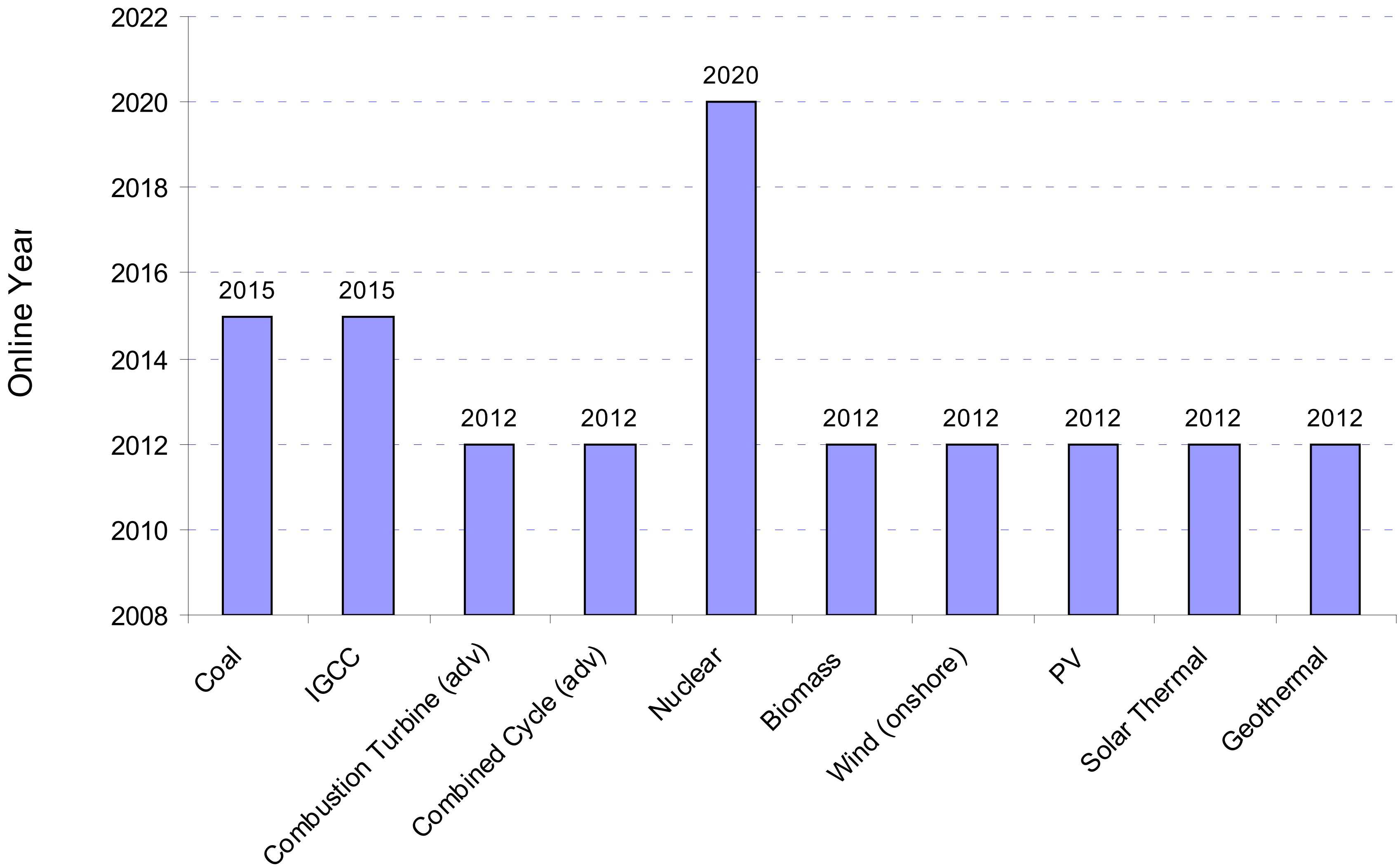


Figure 117. EPA 2009, online year

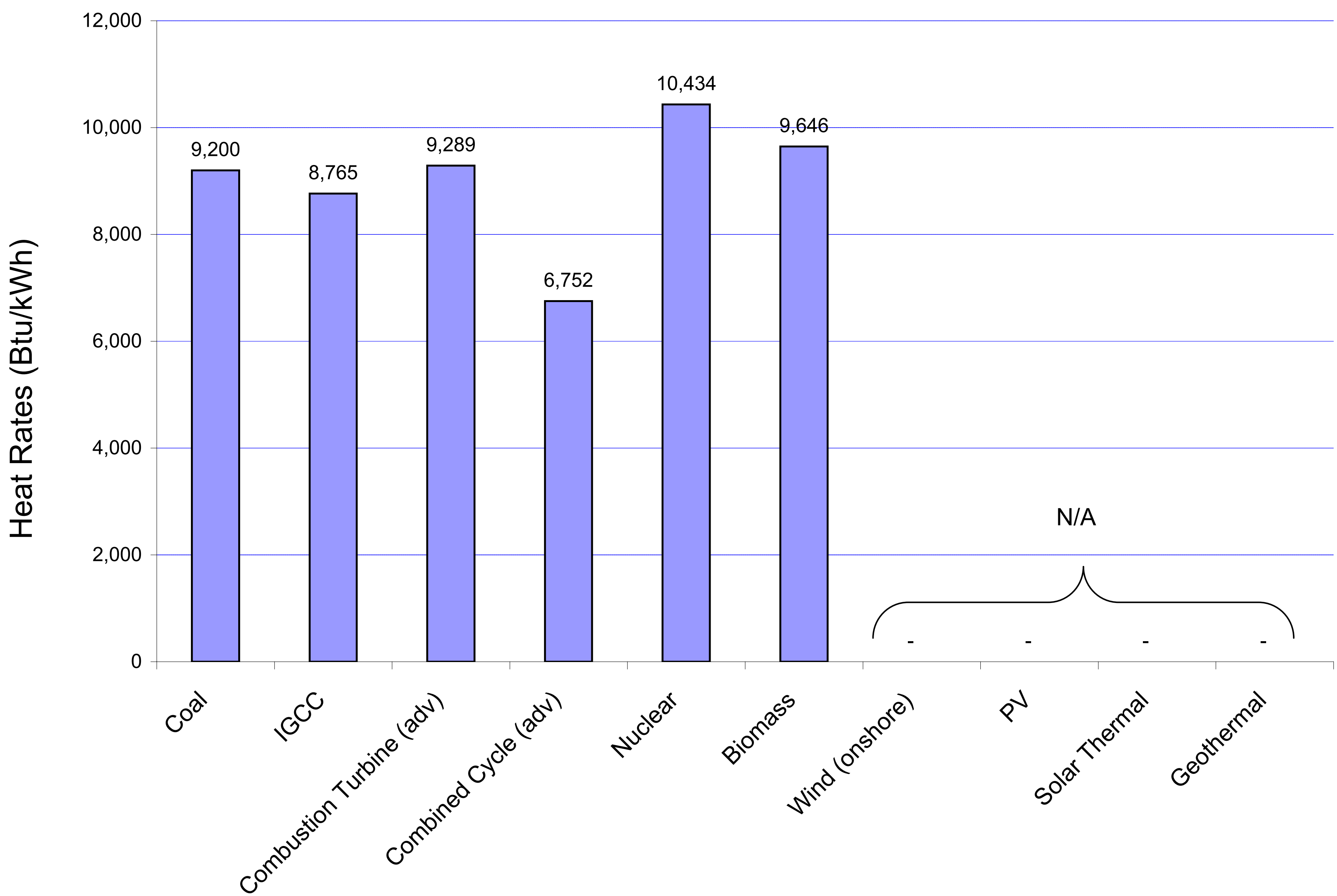


Figure 118. EPA 2009, heat rates

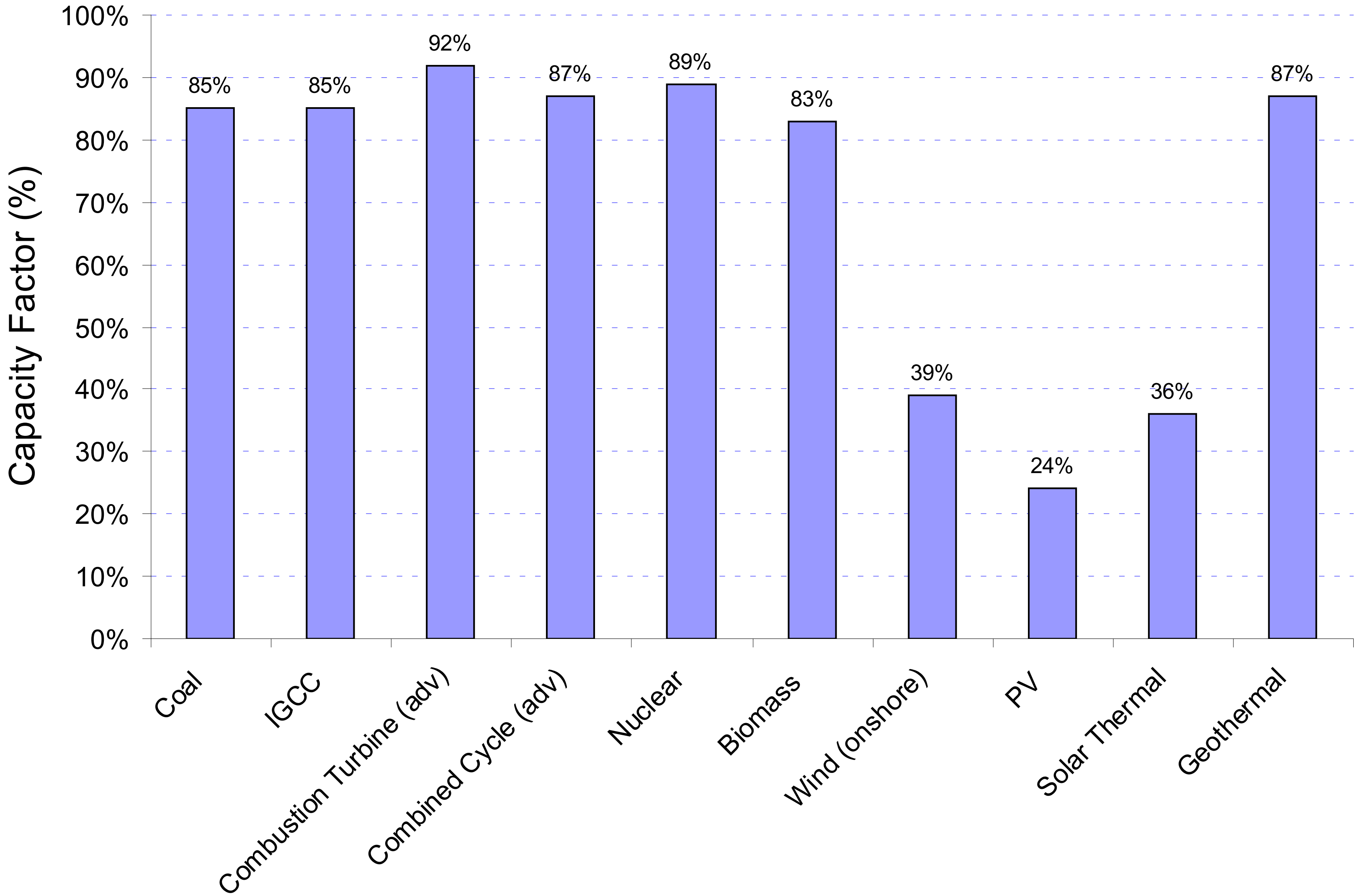


Figure 119. EPA 2009, capacity factors

5.1.10 Cost Characteristics

Overnight Capital Costs

Overnight capital costs and O&M costs for technologies in the EPA 2009 data set are shown in Table 45. These costs correspond to the first year that a technology is adopted (online year).

Table 45. EPA 2009, Cost Data (2006$)

Technology	Overnight Capital Cost (online year, 2006$/kW)	Variable O&M (2006$/MWh)	Fixed O&M (2006$/kW/yr)
Coal	2,113	4.47	26.80
Coal (with CCS)	3,503	4.32	44.90
IGCC	2,414	2.84	37.70
Combustion Turbine (adv)	603	3.09	10.30
Combined Cycle (adv)	903	1.95	11.40
Nuclear	2,995	0.48	87.70
Biomass	3,559	6.50	62.80
MSW, LFG	2,430	2.84	111.30
Fuel Cells	4,983	46.70	5.50
Wind (onshore)	1,831	0.00	29.50
PV	5,614	0.00	11.40
Solar Thermal	4,668	0.00	55.30
Geothermal	9,361	0.00	179.50

Overnight capital costs are shown for 10 technologies in Figure 120. A few notes concerning these costs:

- The geothermal cost of $9,361/kW needs to be viewed with caution. In the EPA data set, geothermal costs are assumed to range from $1,364/kW to $17,358/kW depending on site specific factors. The value of $9,361 is a simple average of these two extremes.
- Most technologies have an online year of 2012. However, the online year for coal and IGCC is 2015, and the online year for nuclear is 2020.
- Most technologies extend through 2035. However, coal, IGCC, combustion turbine, and combined cycle technologies end in 2031.

Learning

Learning factors were calculated using the following formula:

learning factor for year "n" = (capital cost in year n) / (starting year capital cost)

Geothermal, nuclear, PV, solar thermal, and wind show no improvement in costs over time, and have a learning factor of one for all years. Coal, IGCC, combustion turbine, combined cycle, and biomass technologies have learning factors not equal to one over the modeling horizon (see Figure 121).

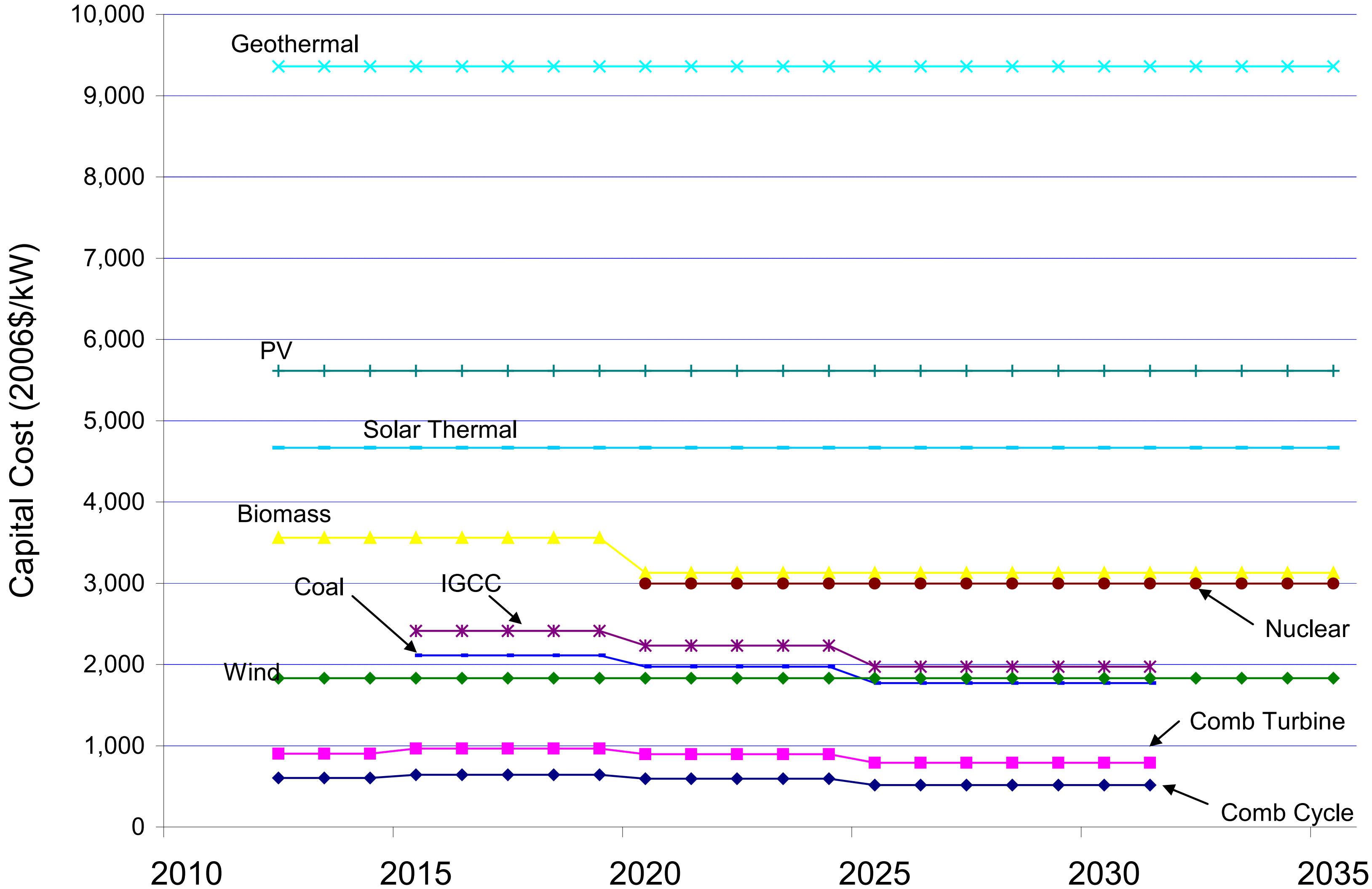


Figure 120. EPA 2009, capital costs

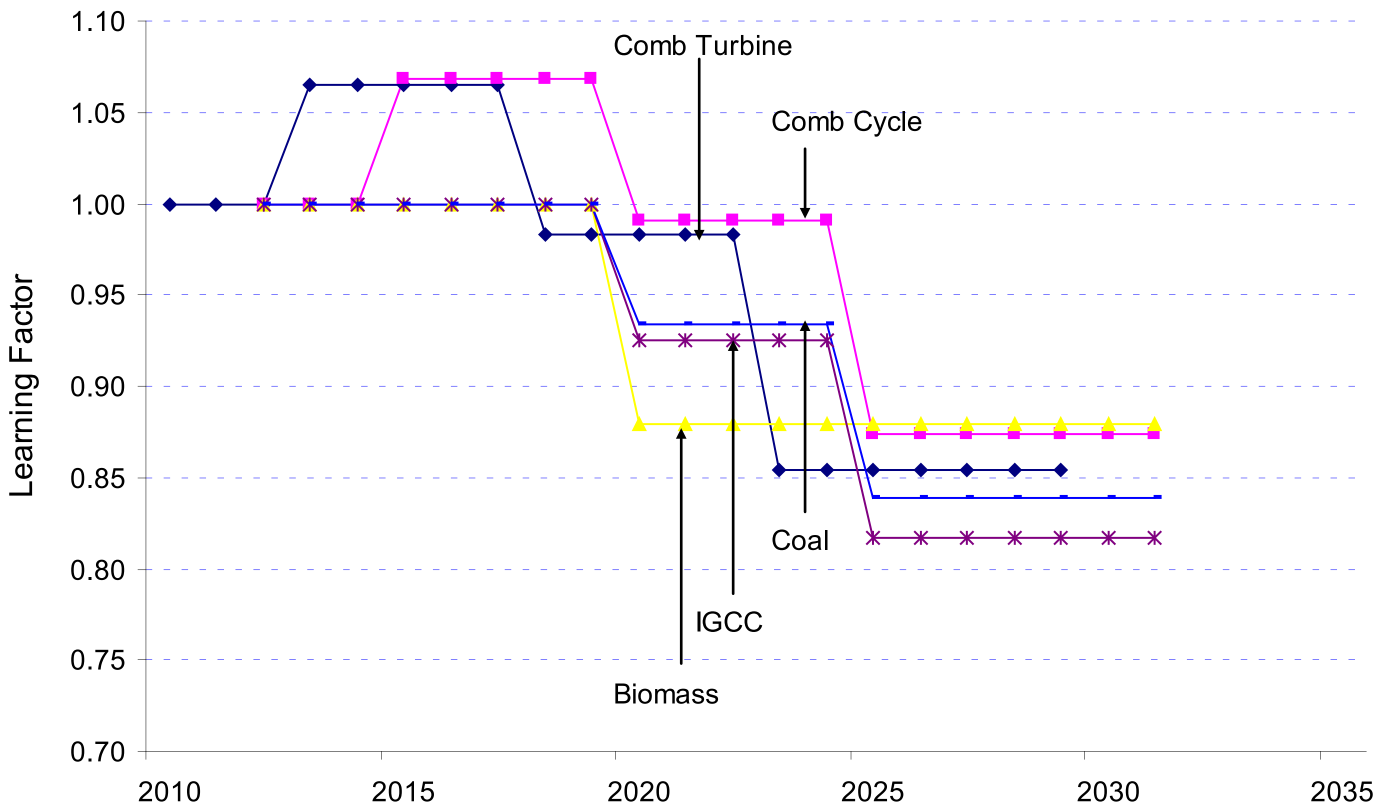


Figure 121. EPA 2009, learning factor

O&M Costs

In the EPA data set, the O&M costs remain fixed over time. Variable O&M costs are shown in Figure 122, and fixed O&M values are compared in Figure 123.

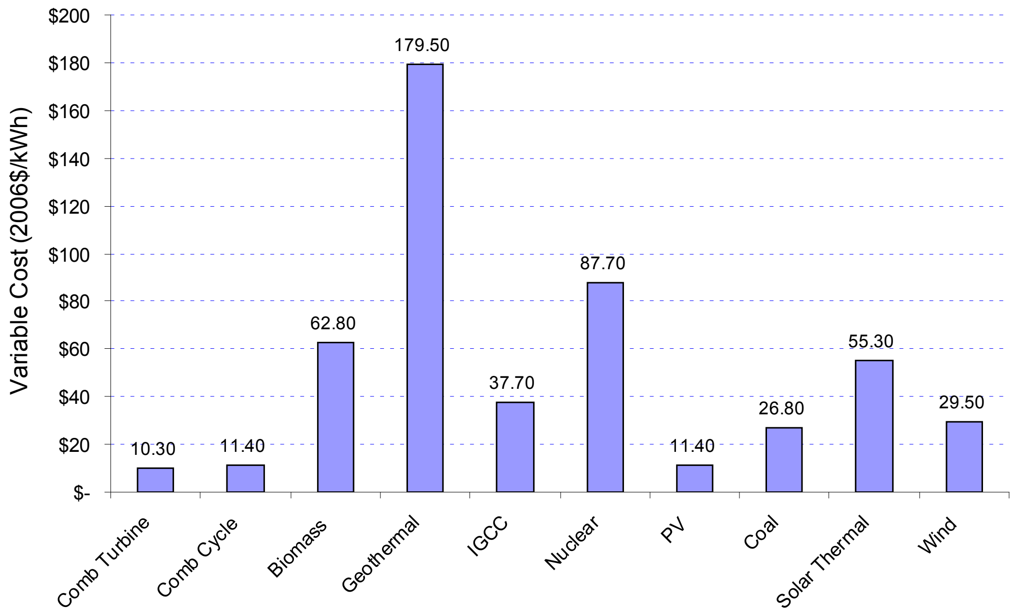


Figure 122. EPA 2009, variable O&M costs

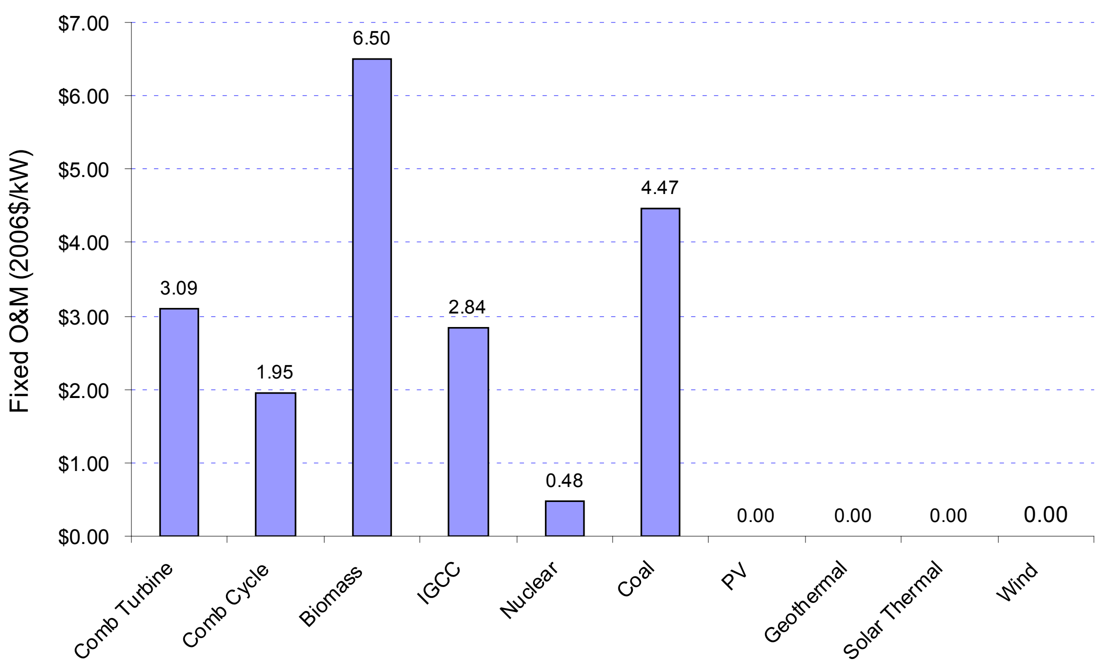


Figure 123. EPA 2009, fixed O&M costs

Appendix F. MERGE (MERGE 2009 Data Set)

The MERGE model is a private sector model developed by the Electric Power Research Institute (EPRI). The power generation technology characteristics used in MERGE are based on EPRI's proprietary Technology Assessment Guide (TAG).[53]

ICF reviewed several MERGE publications, including the following recent publication: "Program on Technology Innovation: Integrated Generation Technology Options," EPRI, Report No. 1019539, November 2009. This report contains overview information with highlights, but does not contain detailed characteristics for power generation technologies over the full modeling horizon. For the most part, characteristics are only reported for two years – 2015 and 2025. One notable characteristic that is not reported is O&M costs.

The 2009 EPRI MERGE report referenced in the preceding paragraph describes characteristics for eight primary power generation technologies, as listed in Table 46. As indicated, two of the technologies – supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) – include options for carbon capture. For the carbon capture options, performance characteristics are provided for both standard (first generation) and advanced (second generation) versions of the technology. For the SCPC and IGCC technologies, the carbon capture technologies are only reported for 2025, and the non-carbon capture designs are reported only for 2015.

Table 46. MERGE 2008, Technologies Covered

Technology	Technology Design		Years Provided	
	CO_2 Capture	Version	2015	2025
Supercritical Pulverized Coal (SCPC)	No	---	X	---
	Yes	1st gen	---	X
	Yes	2nd gen	---	X
Integrated Gasification Combined Cycle (IGCC)	No	---	X	---
	Yes	1st gen	---	X
	Yes	2nd gen	---	X
Combustion Turbine Combined Cycle (CTCC)	no	---	X	X
Nuclear	---	---	X	X
Biomass Circulating Fluidized Bed (CFB)	---	---	X	X
Wind (onshore)[54]	---	---	X	X
Solar Thermal Trough	---	---	X	X
Solar Photovoltaic (PV)	---	---	X	X

[53] Telephone call between ICF and EPRI, November 9, 2009.
[54] The EPRI reports did not distinguish between onshore and offshore wind. However, a quick comparison of the EPRI wind data to the AEO 2009 data for onshore and offshore wind suggests that the EPRI wind data applies to onshore technologies.

Table 47 shows a summary of characteristics for the MERGE technologies for 2015. These characteristics were compiled based on the EPRI documentation as well as ICF estimates in some cases. For example, ICF calculated the O&M costs based on the reported levelized cost of energy (LCOE), overnight capital costs, and fuel costs.

Table 47. MERGE Characteristics for Eight Technologies

(Characteristics for 2015)

Power Generation Technology	Plant Size (MW)	Heat Rate		Capacity Factor (%)	Life (yrs)	Costs (2008$)	
		(%)	(Btu/kWh)			Overnight Capital ($/kW)	O&M (all inclusive, $/MWh)
Coal, no CO_2 capture (CC)	675	38%	8,979	80%	30	$2,650	$23.82
Coal, 1st gen CC	no data in 2015						
Coal, 2nd gen CC	no data in 2015						
IGCC, no CO_2 capture (CC)	800	38%	8,979	80%	30	$2,960	$25.78
IGCC, 1st gen CC	no data in 2015						
IGCC, 2nd gen CC	no data in 2015						
Combined Cycle	450	47%	7,260	80%	30	$880	$7.52
Nuclear	1,400	33%	10,339	90%	30/60[55]	$4,860	$33.31
Biomass	75	28%	12,186	85%	30	$3,580	$29.46
Wind (onshore)	100	N/A	N/A	35%	30	$2,350	$46.26
Solar Thermal[56]	125	N/A	N/A	22%	30	$4,851	$116.81
PV	20	N/A	N/A	26%	30	$7,981	$188.54

The MERGE characteristics, including a discussion of how they were developed, are discussed in the remainder of this section, which is organized as follows:

- Technical Performance Characteristics
    - Plant Size
    - Heat Rate
    - Capacity Factor
    - Plant Lifetime
- Cost Characteristics
    - Overnight Capital Costs
    - Learning
    - O&M Costs (all inclusive)

[55] For economic calculations, all plants (including nuclear) are assumed to operate for 30 years. However, in the actual MERGE analysis, plants are allowed to operate as long as they are economic. Nuclear plants have a fixed retirement age of 60 years.
[56] MERGE contained three scenarios for solar thermal. The data shown in this table, and throughout this section, are based on a scenario with 100% solar and wet cooling.

5.1.11 Technical Performance Characteristics

Plant Size

The nameplate plant capacities are shown in Figure 124. As indicated, the capacities range from 20 MW for solar PV to 1,500 MW for nuclear. The capacities remain constant between 2015 and 2025 with the exception of nuclear (increase from 1,400 MW to 1,500 MW).

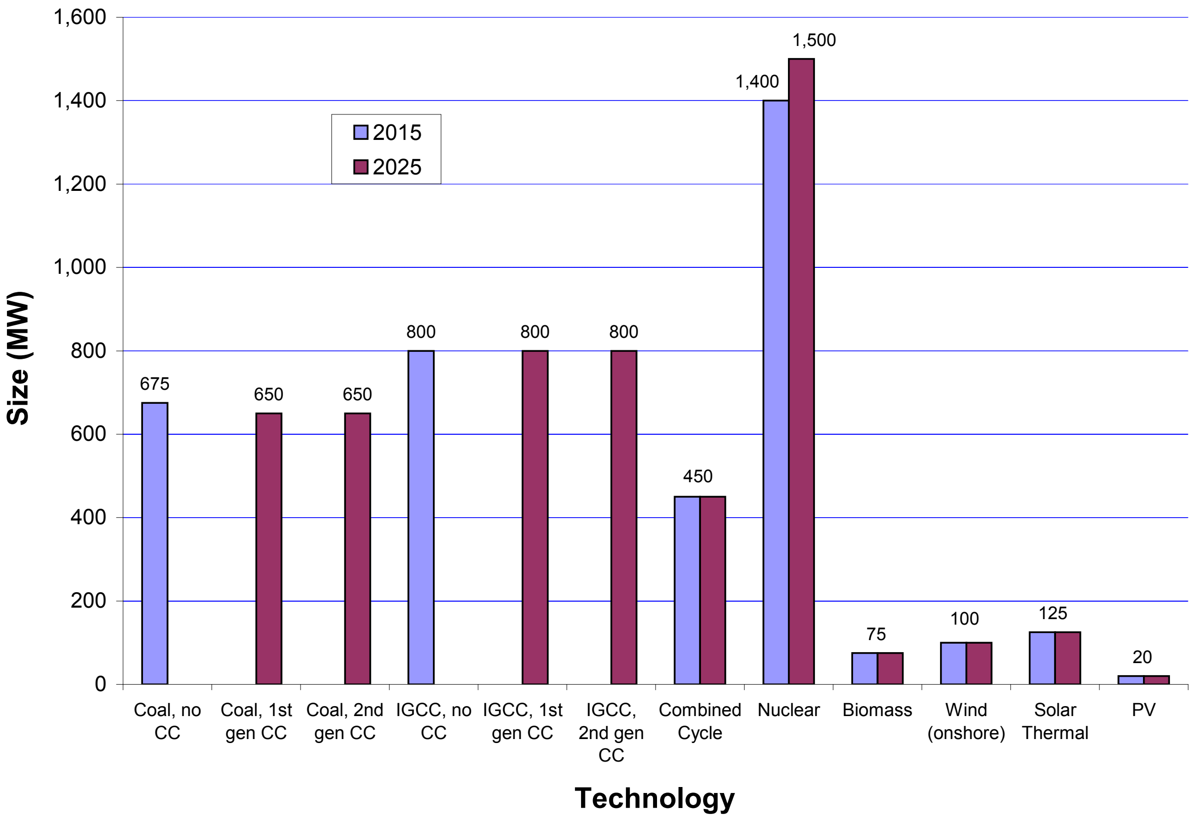


Figure 124. MERGE, plant size

Heat Rate

The EPRI MERGE documentation provides heat rates for two years – 2015 and 2025 – and these heat rates are shown in Table 48 and Figure 125. As indicated, the heat rates for nuclear and biomass technologies remain constant for the two years (10,339 and 12,186, respectively). The combined cycle system has an improved heat rate over time – declining from 7,260 Btu/kWh in 2015 to 6,319 Btu/kWh in 2025.

Table 48. MERGE, Heat Rates

Power Generation Technology		Heat Rate by Year (Btu/kWh)	
		2015	2025
	Coal, no CC	8,979	---
Coal	Coal, 1st gen CC	---	12,637
	Coal, 2nd gen CC	---	10,339
	IGCC, no CC	8,979	---
IGCC	IGCC, 1st gen CC	---	11,006
	IGCC, 2nd gen CC	---	10,035
Combined Cycle	---	7,260	6,319
Nuclear	---	10,339	10,339
Biomass	---	12,186	12,186
Wind (onshore)	---	N/A	N/A
Solar Thermal[57]	---	N/A	N/A
PV	---	N/A	N/A

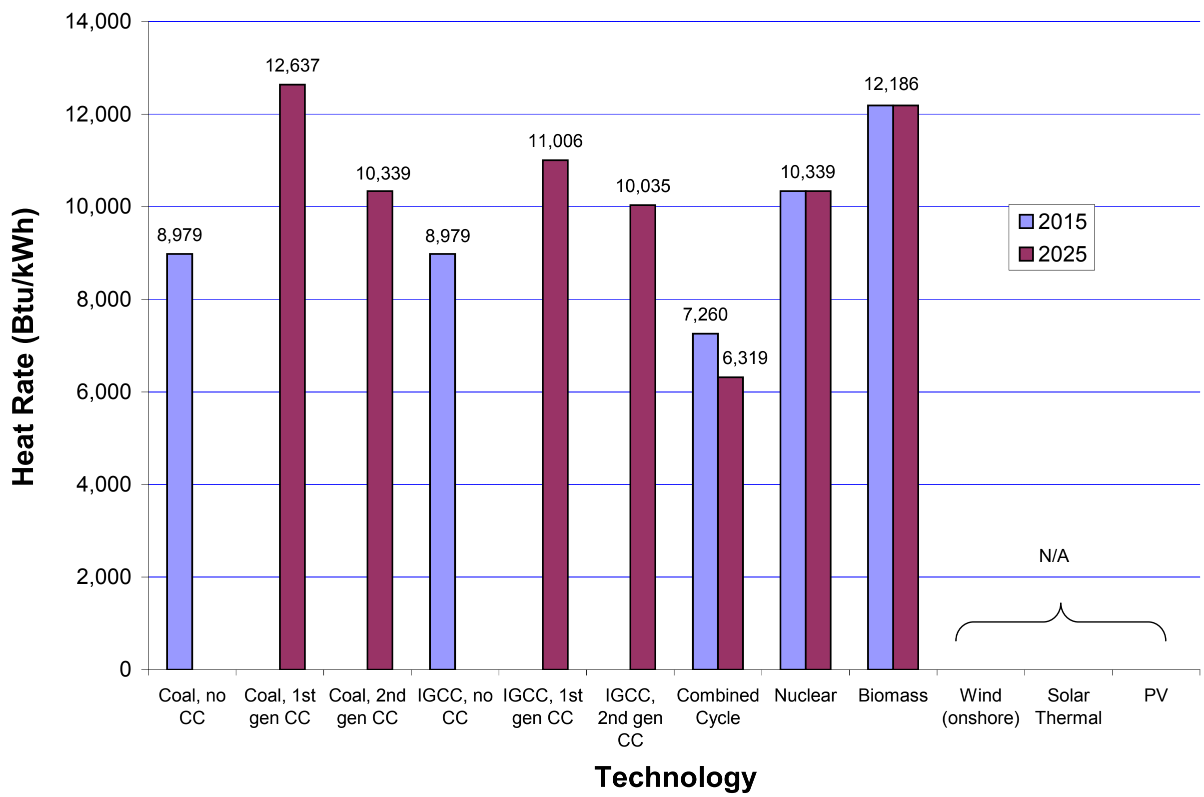


Figure 125. MERGE, heat rates

[57] MERGE contained three scenarios for solar thermal. The data shown in this table, and throughout this section, are based on a scenario with 100% solar and wet cooling.

Capacity Factors

The capacity factors are shown in Table 49, and graphed in Figure 126. All fossil technologies have a capacity factor of 80%, and nuclear is set at 90% (in both 2015 and 2025). Biomass, solar thermal, and PV are modeled with constant capacity factors of 85%, 22%, and 26%, respectively. The wind capacity factor increases from 35% in 2015 to 42% in 2025.

Table 49. MERGE, Capacity Factors

Power Generation Technology		**Capacity Factor by Year (%)**	
		2015	**2025**
Coal	Coal, no CC	80%	---
	Coal, 1st gen CC	---	80%
	Coal, 2nd gen CC	---	80%
IGCC	IGCC, no CC	80%	---
	IGCC, 1st gen CC	---	80%
	IGCC, 2nd gen CC	---	80%
Combined Cycle	---	80%	80%
Nuclear	---	90%	90%
Biomass	---	85%	85%
Wind (onshore)	---	35%	42%
Solar Thermal[58]	---	22%	22%
PV	---	26%	26%

[58] MERGE contained three scenarios for solar thermal. The data shown in this table, and throughout this section, are based on a scenario with 100% solar and wet cooling.

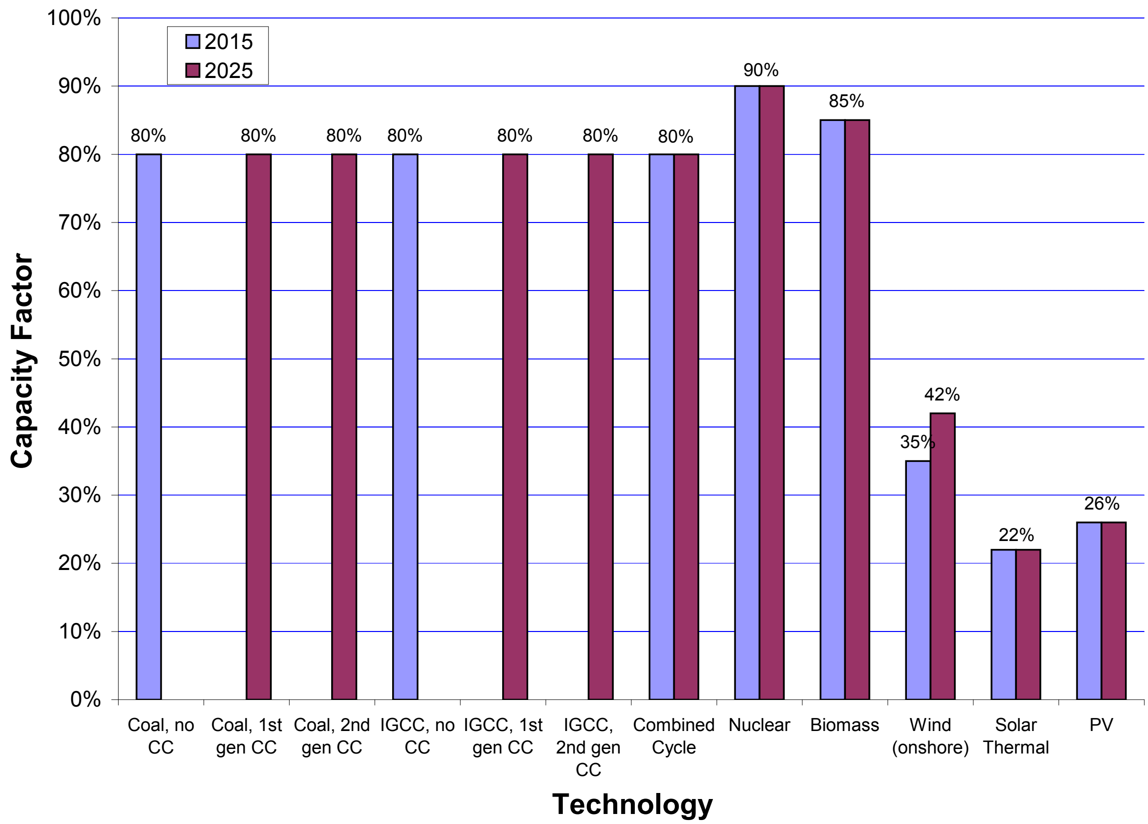


Figure 126. MERGE, capacity factors

Plant Lifetime

Based on an e-mail exchange with EPRI personnel,[59] it was explained that levelized cost of energy (LCOE) calculations are computed using a plant lifetime value of 30 years for all technologies. The levelized costs were first developed in the EPRI Technical Assessment Guide (TAG), and then used as inputs for the MERGE analysis.

While LCOE values are calculated on a 30 year basis, the MERGE model allows plants to operate as long as they are economical. One exception is nuclear plants, which are retired after 60 years of operation.

5.1.12 Cost Characteristics

Overnight Capital Costs

Overnight capital costs for 2015 and 2025 are shown in Table 50. These costs range from a low of $880/kW for a combustion turbine combined cycle plant in 2015, to $7,981/kW for PV technology (all costs reported in 2008 dollars). For coal and IGCC plants without CO_2 capture, data are only reported for 2015. Coal and IGCC technologies with CO_2 capture have costs reported in 2025. For those technologies that have costs reported in both 2015 and 2025, overnight capital costs remain constant except for combined cycle and nuclear plants. The combined cycle plant shows a slight increase from $880/kW to $902/kW (2.5% increase), while the nuclear plant shows a reduction from $4,860/kW to $4,127/kW (15% reduction).

[59] Revis James (EPRI) and Rick Tidball (ICF), December 18, 2009.

Table 50. MERGE, Overnight Capital Costs

Technology		Overnight Capital Cost by Year (2008$/kW)	
		2015	2025
Coal	Coal, no CC	$2,650	---
	Coal, 1st gen CC	---	$4,435
	Coal, 2nd gen CC	---	$3,678
IGCC	IGCC, no CC	$2,960	---
	IGCC, 1st gen CC	---	$4,083
	IGCC, 2nd gen CC	---	$3,317
Combined Cycle	---	$880	$902
Nuclear	---	$4,860	$4,127
Biomass	---	$3,580	$3,580
Wind (onshore)	---	$2,350	$2,350
Solar Thermal[60]	---	$4,851	$4,851
PV	---	$7,981	$7,981

The MERGE model extends to the year 2050, and the cost data shown in Table 50 provide only a glimpse of how overnight capital costs are expected to change over time. These limited data were interpolated and extrapolated to produce the cost curves shown in Figure 127 (fossil and nuclear) and Figure 128 (renewables). In these figures, the 2015 capital costs are assumed to apply for the time period of 2010 through 2024, and the 2025 capital costs are assumed to apply from 2025 and beyond.

[60] MERGE contained three scenarios for solar thermal. The data shown in this table, and throughout this section, are based on a scenario with 100% solar and wet cooling.

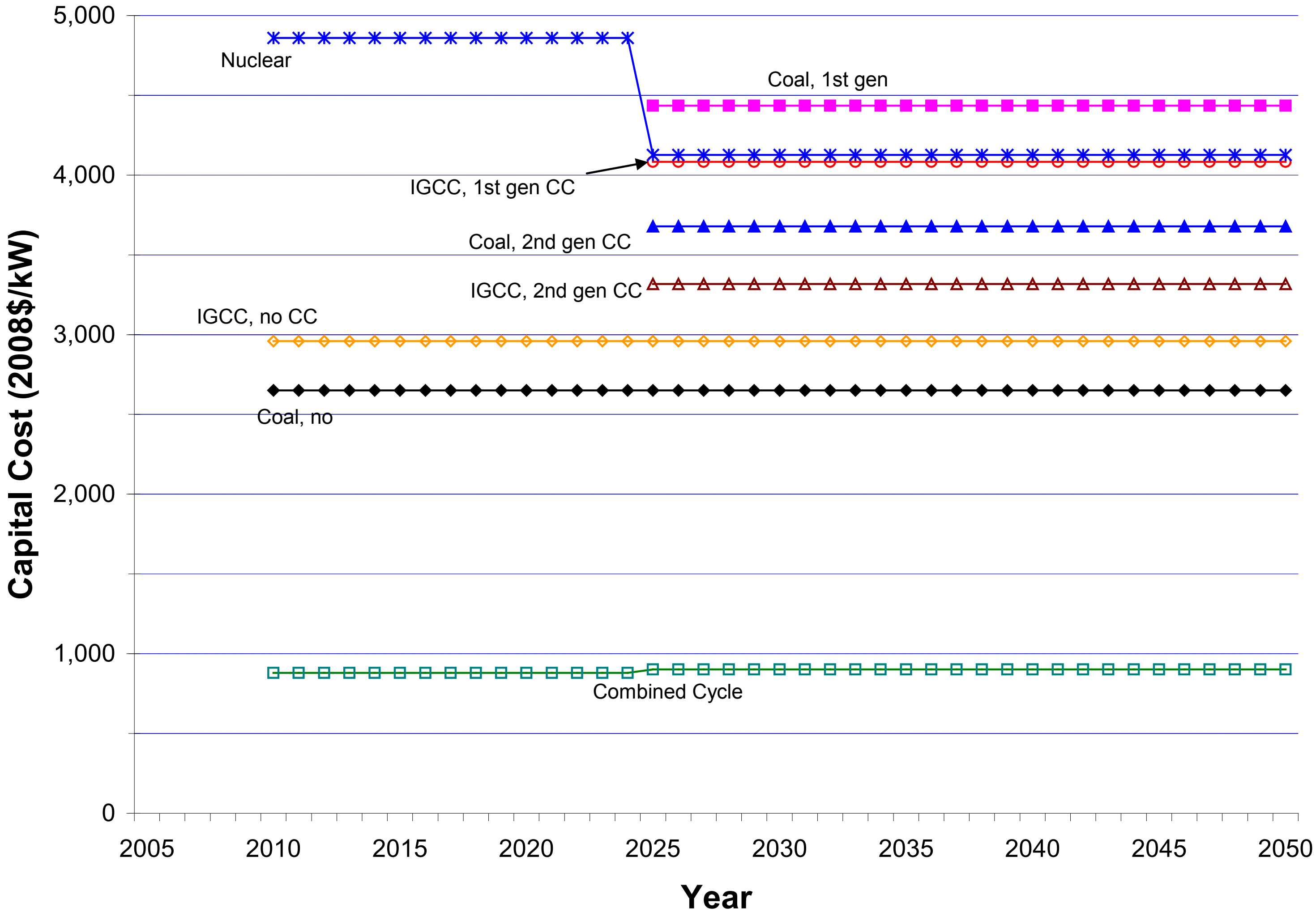


Figure 127. MERGE, overnight capital costs, fossil and nuclear

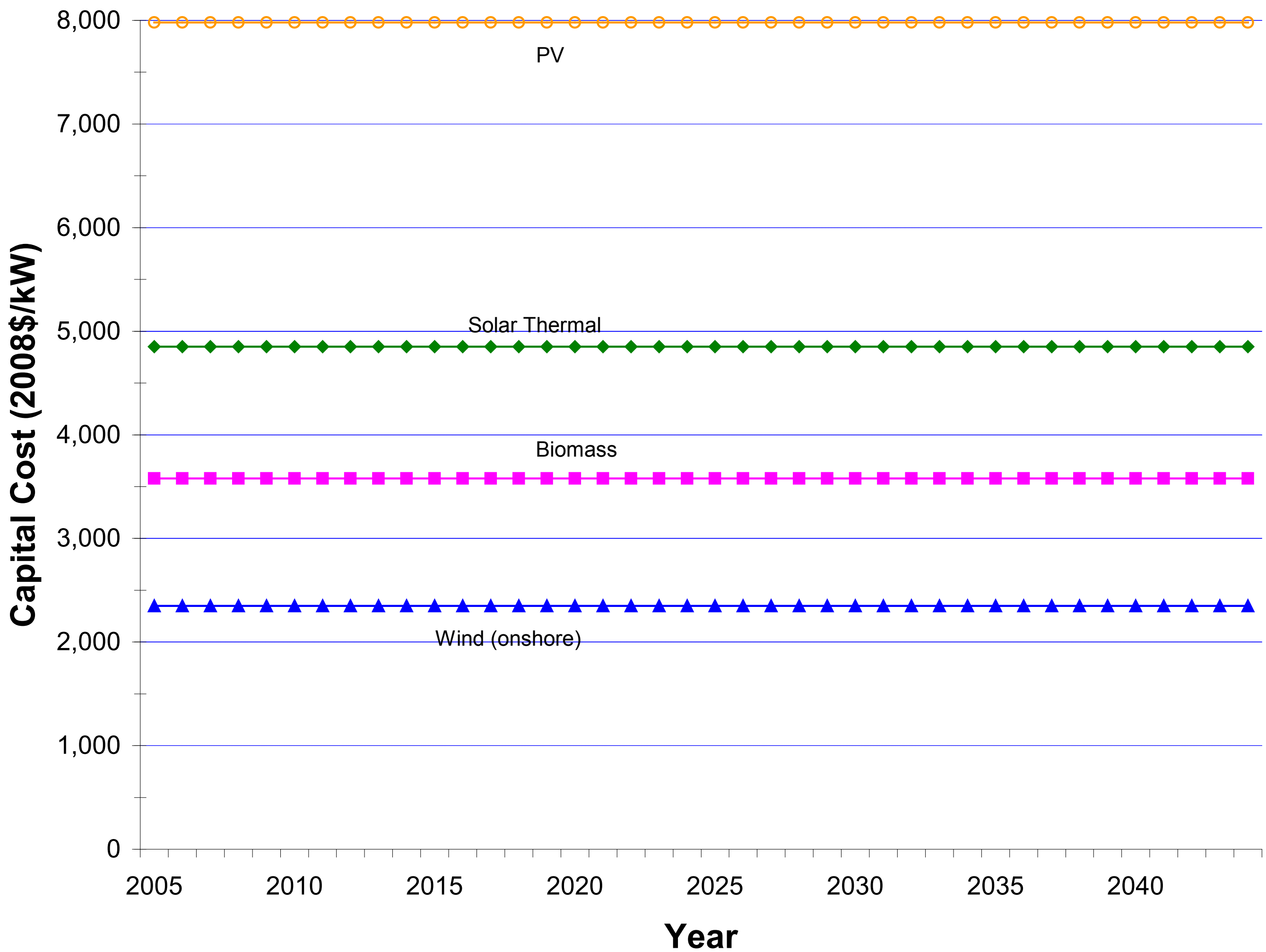


Figure 128. MERGE, overnight capital costs, renewables

Learning

EPRI indicated that learning is handled as an exogenous input to MERGE[61] (presumably developed in the EPRI Technical Assessment Guide). EPRI reported that, for most technologies, the learning rates are conservative, with the exception of fast growing technologies like wind and solar.

Based on the limited data available, it appears that no learning occurs for biomass, onshore wind, and solar thermal technologies, at least for the time period between 2015 and 2025 (i.e., the costs remain unchanged over this time period). Learning does seem apparent for nuclear technologies (decrease in cost between 2015 and 2025). The reason for the slight increase in combined cycle technology cost is probably due to introduction of advanced technology (GE 7F machine in 2015, and GE 7H machine in 2025).[62]

O&M Costs (all inclusive)

The EPRI literature provided no details on either fixed or variable O&M costs. However, the EPRI literature did provide LCOE values and fuel costs, and, based on these LCOE values and fuel costs, an "all inclusive" O&M cost was calculated (in $/MWh).

The all inclusive O&M costs, which include both fixed and variable O&M, were reverse calculated using the following LCOE formula[63]:

$$LCOE_{real} = \frac{OC * CT * S + \sum \frac{[FC * (1 + FE) + FOM * S + VOM * MWh * (1 - DF)^n]}{(1 + DR_{nominal})^n}}{\sum \frac{[MWh * (1 - DF)]^n}{(1 + DR_{real})^n}}$$

The variables used in the preceding LCOE equation are described in Table 51. In simple terms, the all inclusive O&M cost is equal to the LCOE cost less the annualized capital cost and less the annualized fuel cost (i.e., O&M Cost = LCOE – Annual Capital – Annual Fuel).

Table 51. LCOE Calculation Parameters

Abbreviation	Description	Units
$LCOE_{nominal}$	Levelized Cost of Energy (nominal dollars)	$/MWh
$LCOE_{real}$	Levelized Cost of Energy (real dollars)	$/MWh
OC	Overnight Capital Cost	$/kW
CT	Construction Cost Multiplier	---
FC	Fuel Cost (with inflation)	$/MMBtu
FE	Fuel Escalation Factor (annual change above inflation)	%
FOM	Fixed O&M (with inflation)	$/kW/yr

[61] E-mail exchange between R. James (EPRI) and R. Tidball (ICF), January 12, 2010.

[62] Program on Technology Innovation: Integrated Generation Technology Options, EPRI, Report No. 1018329, November 2008, Tables 1-4 and 1-5, (GE machines referenced in combined cycle discussion).

[63] LCOE equation discussed in greater detail in the following companion report: "Cost and Performance of Electricity Generation Technologies, Task 3 – Levelized Cost of Energy (LCOE) Tool Development."

Abbreviation	Description	Units
VOM	Variable O&M (with inflation)	$/MWh
DF	Degradation Factor (annual decline in maximum plant capacity)	%
S	Plant Capacity (nameplate)	MW
CF	Capacity Factor	%
MWh	Electricity Production (= S X CF X 8,760 hrs/yr)	MWh/yr
n	Number of Years (1 through end of plant lifetime)	---
e	Inflation Rate	%
$DR_{nominal}$	Nominal Discount Rate	%
DR_{real}	Real Discount Rate (= $[DR_{nominal} + 1] / [1 + e] - 1$)	%

The all inclusive O&M results for 2015 and 2025 are shown in Table 52 and Figure 129. The table shows the calculated O&M results as well as the LCOE and fuel costs used to calculate the O&M results. As indicated, the all-inclusive O&M costs range from a low of $7.52/MWh for a combined cycle plant to $188/MWh for a PV system.

Table 52. MERGE, All Inclusive O&M Costs (2015 values, reported in 2008$)

Technology		Fuel (2008$/MMBtu)	LCOE (2008$/MWh)		All Inclusive O&M (2008$/MWh)	
		2015 & 2025	2015	2025	2015	2025
Coal	Coal, no CC	$1.80	$66.00	---	$23.82	---
	Coal, 1st gen CC	$1.80	---	$101.00	---	$34.71
	Coal, 2nd gen CC	$1.80	---	$86.00	---	$31.28
IGCC	IGCC, no CC	$1.80	$71.00	---	$25.78	---
	IGCC, 1st gen CC	$1.80	---	$92.00	---	$32.10
	IGCC, 2nd gen CC	$1.80	---	$78.00	---	$27.37
Combined Cycle	---	$9.00	$81.50	$74.00	$7.52	$8.27
Nuclear	---	$0.80	$84.00	$74.00	$33.31	$29.71
Biomass	---	$1.72	$83.50	$77.00	$29.46	$22.96
Wind (onshore)	---	---	$99.00	$82.00	$46.26	$38.05
Solar Thermal[64]	---	---	$290.00	$290.00	$116.81	$116.81
PV	---	---	$456.00	$456.00	$188.54	$188.54

[64] MERGE contained three scenarios for solar thermal. The data shown in this table, and throughout this section, are based on a scenario with 100% solar and wet cooling.

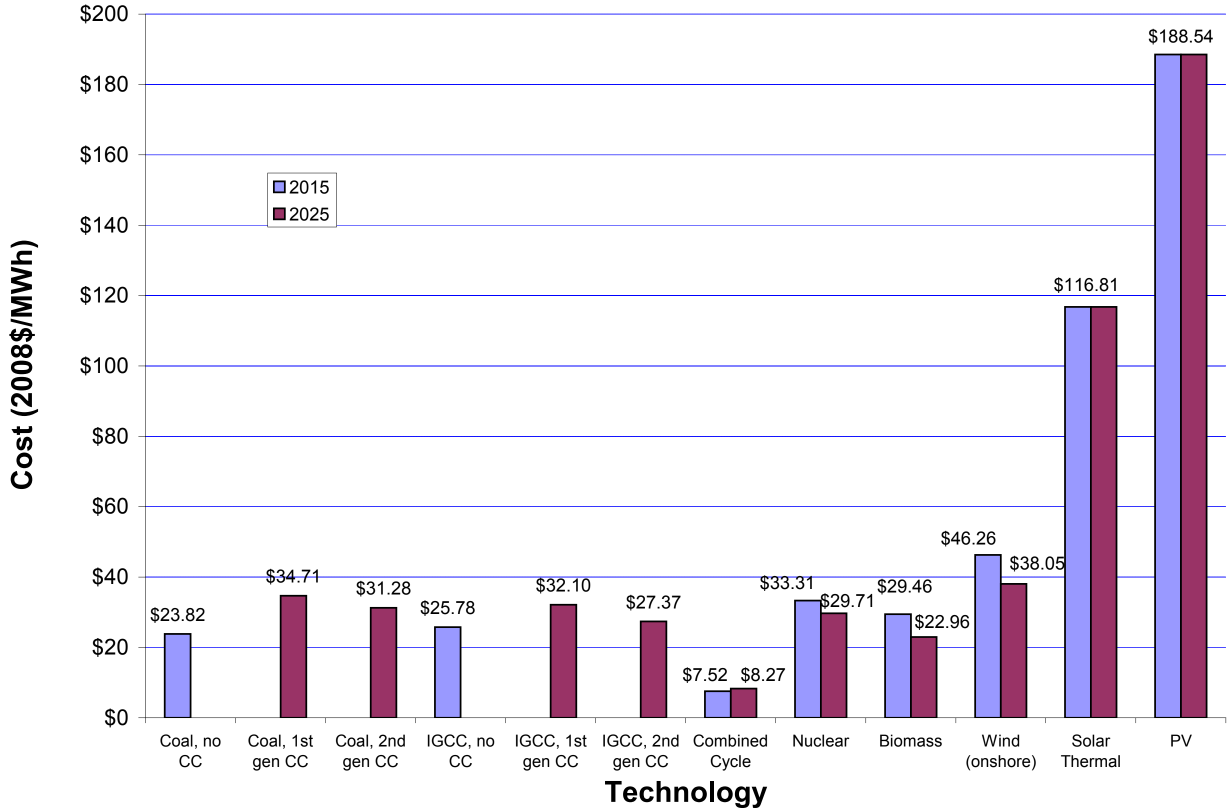


Figure 129. MERGE, all inclusive O&M costs

Appendix G. Description of LCOE Tool

A calculation tool was created to compute the levelized cost of energy (LCOE) for power generation technologies. The tool was created in Excel and is named "***LCOE_ver_x.xls"*** (x signifies the version number). This appendix describes the calculation methodology used in the Excel tool, and provides guidance on the input parameters required for the tool and the output results that are computed. The discussion is organized as follows:

- Methodology
- Excel Workbook Structure
- Excel Worksheet Descriptions

5.1.13 Methodology

LCOE results are calculated in both nominal and real dollars. The equations used for these LCOE calculations are shown below (first equation in nominal dollars and second equation in real dollars):

$$LCOE_{nom} = \frac{OC * CT * S + \sum \frac{[FC * (1 + FE) + FOM * S + VOM * MWh * (1 - DF)^{n}]}{(1 + DR_{nominal})^{n}}}{\sum \frac{[MWh * (1 - DF)]^{n}}{(1 + DR_{nominal})^{n}}}$$

$$LCOE_{real} = \frac{OC * CT * S + \sum \frac{[FC * (1 + FE) + FOM * S + VOM * MWh * (1 - DF)^{n}]}{(1 + DR_{nominal})^{n}}}{\sum \frac{[MWh * (1 - DF)]^{n}}{(1 + DR_{real})^{n}}}$$

The variables used in the preceding LCOE equations are described in Table 53.

Table 53. LCOE Calculation Parameters

Abbreviation	Description	Units
$LCOE_{nominal}$	Levelized Cost of Energy (nominal dollars)	$/MWh
$LCOE_{real}$	Levelized Cost of Energy (real dollars)	$/MWh
OC	Overnight Capital Cost	$/kW
CT	Construction Cost Multiplier	---
FC	Fuel Cost (with inflation)	$/MMBtu
FE	Fuel Escalation Factor (annual change above inflation)	%
FOM	Fixed O&M (with inflation)	$/kW/yr
VOM	Variable O&M (with inflation)	$/MWh
DF	Degradation Factor (annual decline in maximum plant capacity)	%
S	Plant Capacity (nameplate)	MW
CF	Capacity Factor	%
MWh	Electricity Production (= S X CF X 8,760 hrs/yr)	MWh/yr
n	Number of Years (1 through end of plant life)	---
e	Inflation Rate	%
$DR_{nominal}$	Nominal Discount Rate	%
DR_{real}	Real Discount Rate (= [$DR_{nominal}$ + 1] / [1 + e] - 1)	%

The fuel cost (FC), fixed O&M (FOM), and variable O&M (VOM) factors include inflation based on the following equations:

$$FC_j = FC_{j-1} * MWh_j * (1+e)$$

$$FOM_j = FOM_{j-1} * (1+e)$$

$$VOM_j = VOM_{j-1} * (1+e)$$

where "j" is the particular year and "e" is the inflation rate.

The construction cost multiplier (CT) is also adjusted with inflation as follows:

$$CT = CT_0 * (0.97 + e)$$

where CT_0 is the baseline construction cost multiplier for a particular technology at 3% inflation.

5.1.14 Excel Workbook Structure

Figure 130 shows a flow chart for the LCOE tool. As indicated, the first step is to select a single comparison year for the analysis. Based on the comparison year selected, power plant characteristics from a companion Access database are imported into the LCOE tool for the data sets shown in Table 1. The Access database, which is named "***TechChar.mdb,"*** needs to be saved in the same folder as the LCOE Excel file to establish a proper data transfer path.

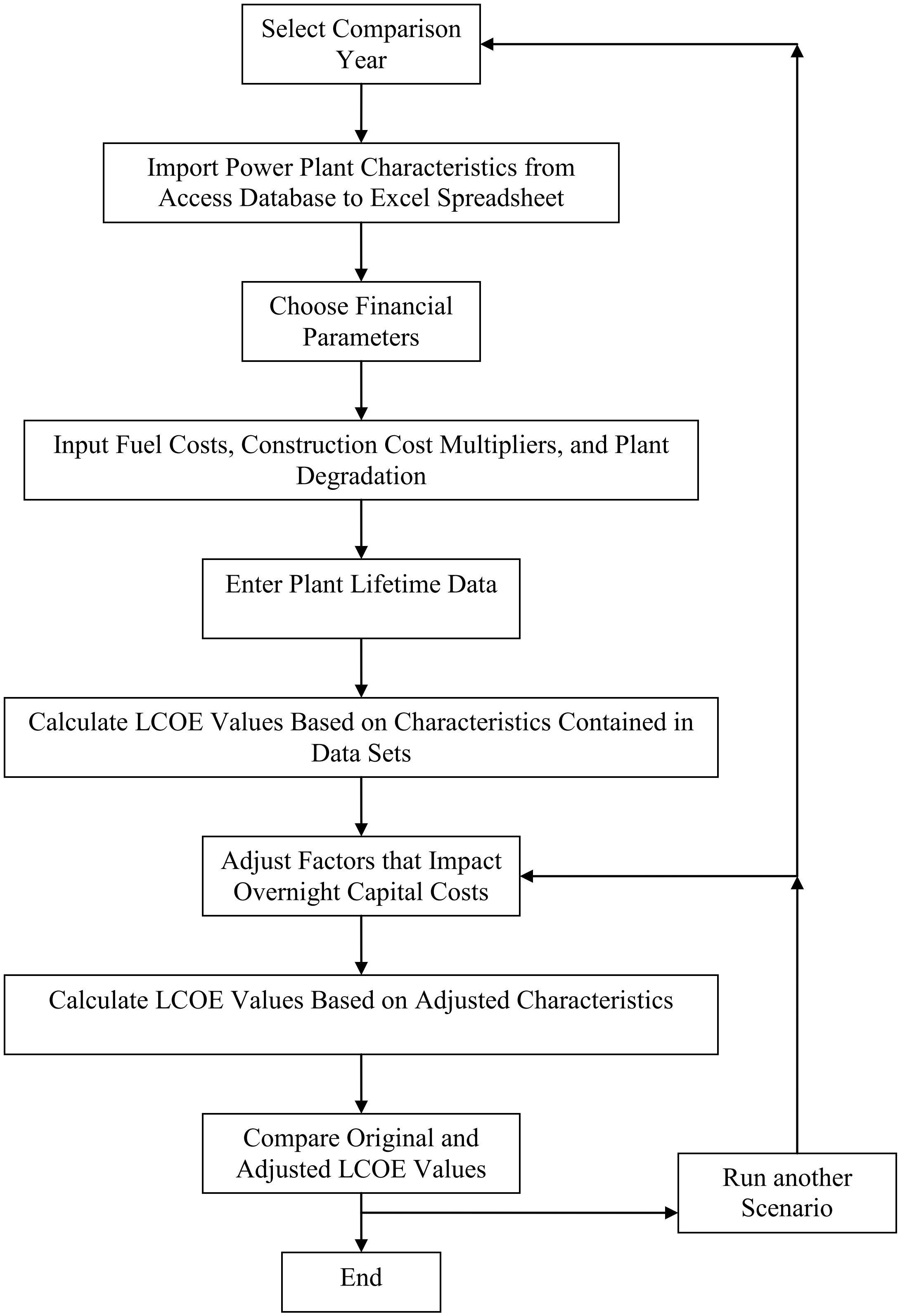


Figure 130. Flow chart for the LCOE tool

The Access database contains technical performance and cost characteristics for power plant technologies. However, additional data is required to compute LCOE values. After the power plant characteristics are imported into the spreadsheet, the user is guided through a series of steps (see Figure 130) to supply additional data needed to run the LCOE calculations. After the required data has been entered, baseline LCOE values are computed for the data sets.

In addition to computing baseline LCOE values for the six data sets, the user can create customized technical performance and cost characteristics for a “user defined” data set. Up to 29 unique power generation technologies can be characterized in this user defined data set. The LOCE values for the user defined data set are calculated in the LCOE spreadsheet.

After computing the baseline LCOE values in the six sets and the user defined data set, the user then has the ability to change a number of factors, such as learning and capital cost contributions. LCOE values are then re-computed based on the adjustments entered by the user. The user can then repeat the preceding steps to examine multiple scenarios for different parameter adjustments.

The workbook contains several macros to facilitate calculations. The principal macros are described in Table 54.

5.1.15 Excel Worksheet Descriptions

The Excel workbook is divided into several worksheets as listed in Table 55. In the following paragraphs, each of these worksheets is briefly discussed.

Introduction

This worksheet describes what calculations are completed and how the workbook is organized.

Year

This worksheet is used to enter the desired year for comparing power plant characteristics between the data sets. The user is prompted to enter a year, and based on the year selected, data is then imported from a companion Access database to the Excel spreadsheet.

Note that the Access database, which is named “***TechChar.mdb,”*** and the Excel workbook, which is named “***LCOE_ver_x.xls,”*** need to be saved in the same folder to ensure that a path can be created between the two files for data exchange.

Table 54. Macros

Macro	Sub-macros	Action
DatabaseLCOETable	---	Imports data from Access database to Excel spreadsheet for a single year entered by the user.
copy_methodology	---	The LCOE methodology is copied from the “Methodology” worksheet to the “Calculations” worksheet
baseline	aeo_copy_data calc_LCOE aeo_fill_base_nom aeo_fill_base_real	The “baseline” macro runs a set of four macros for each data set (including the user defined data set. Four macros for the AEO data set are shown for illustration. The real and nominal LCOE values are calculated for all technologies in each data set (up to 29 technologies per data set), and the key results are transferred to the “LCOE base nom” and “LCOE base real” worksheets.
adjust	aeo_copy_adjusted calc-LCOE aeo_fill_adj_nom aeo_fill_base_real	The “adjust” macro runs a set of four macros for each data set (including the user defined data set). The four macros for the AEO data set are shown for illustration. The real and nominal LCOE values are calculated for all technologies in each data set (up to 29 technologies per data set) based on adjusted overnight capital costs. Key results are transferred to the “LCOE adj real” and “LCOE adj nom” worksheets.
update	---	This macro runs both the “baseline” and “adjust” macros

Table 55. Worksheets in Excel Workbook

Worksheet Title	Type of Content	Description
Intro	Reference	This worksheet describes what the spreadsheet calculates and how the workbook is organized.
Year	Imported Data from Access database	This worksheet is used to select the comparison year used for the analysis. Based on the comparison year, data from a companion Access database will be imported for the data sets.
Currency	Input	On this worksheet, the user provides the currency year for reporting financial results, and applicable interest rates needed to run the financial calculations.
GDP Index	Input	This worksheet shows the macroeconomic index used to adjust capital and O&M costs. The default values are based on a GDP index. However, these default values can be changed.
Fuel	Input	On this sheet, the user determines fuel costs for coal, natural gas, and uranium. Users can provide customized costs or select from a menu of fuel costs that have been previously developed.
Construction	Input	This sheet shows construction cost multipliers that are applied to all overnight capital costs.
Degradation	Input	This sheet shows the expected annual decline in energy output from PV systems.
Lifetime	Input	This sheet is used to insert user specified plant lifetime data.
LCOE Base Nom	Output	This worksheet shows the baseline LCOE values calculated from the parameters input on the preceding worksheets as well as the plant characteristics contained in the data sets. The LCOE results are reported in nominal dollars.
LCOE Base Real	Output	This worksheet is similar to the previous worksheet, except the LCOE results are reported in real dollars.
Cost Contribution	Input	This worksheet shows a breakdown of overnight capital cost components for each of the power generation technologies. These values are used in conjunction with user specified adjustments (see next work sheet).
Cost Adj	Input	This worksheet allows the user to adjust factors, such as learning and cost components, that impact overnight capital costs.
LCOE Adj Nom	Output	This worksheet shows the impact of the adjusted overnight capital costs on LCOE values (nominal dollars).
LCOE Adj Real	Output	This worksheet shows the impact of the adjusted overnight capital costs on LCOE values (real dollars).
LCOE Comp Nom	Output	This sheet compares baseline and adjusted values (in nominal dollars).
LCOE Comp Real	Output	This sheet compares baseline and adjusted values (in real dollars).
Methodology	Equations	This worksheet contains the LCOE equations.
Calculations	Intermediate Calculations	This worksheet is used to complete all LCOE calculations. The methodology is copied from the preceding worksheet to this worksheet for each set of calculations.
Data Set Sheets	Data Summary	These worksheets show the power plant characteristics for the individual data sets – one worksheet for each data set.
User Defined	Input	This worksheet is used to enter customized power plant characteristics for a user defined data set.
Charts and Tables	Summary of Results	Following the “User Defined” worksheet, there are several summary tables and charts.

Currency

This sheet is used to enter the following parameters:

- Desired currency year
- Discount rate (real)
- Inflation rate

Based on the real discount rate and the inflation rate, a nominal discount rate is automatically computed.

GDP Index

This worksheet contains the indices used to adjust financial data to the currency year supplied by the user on the “Currency” worksheet. The default adjustments are based on a gross domestic product (GDP) index that is consistent with the index used in the AEO 2009 data set. An alternate index can be supplied. For example, if a producer price index (PPI) or power plant index is desired, the user can enter this data by following the instructions on the worksheet.

Fuel

On this worksheet, the user selects fuel costs and fuel escalation factors for coal, natural gas, and uranium. The fuel escalation factor accounts for cost increases that occur above the inflation rate. The user can enter customized fuel prices and escalation factors, or select from three pre-determined fuel cost tables. The pre-determined fuel costs are based on the AEO 2009, NREL-SEAC 2008, and EPA 2009 data sets. These three data sets represent a cross section of all data sets covered in the LCOE tool.

In addition to selecting the fuel price and escalation factor, the user must also select a currency year and an applicable year for each fuel. Fuel costs in the desired comparison year (entered on the “Year” worksheet) and in the desired currency, dollars (entered on the “Currency” worksheet) are automatically calculated.

Note that fuel costs only apply to fossil and nuclear technologies. In the LCOE spreadsheet tool, fuel costs for all renewable technologies are set to zero.

Construction

A uniform set of construction cost multipliers are applied to all technologies in all data sets and the user defined data set. There are a total of 29 technologies represented in the data sets, and default construction cost multipliers for these 29 technologies are shown on this worksheet. The default values can be changed by the user.

The default construction cost multipliers were derived from the ReEDS 2009 data set. For technologies not covered in the ReEDS 2009 data set, construction cost multipliers were adapted to provide full coverage across all 29 technologies in the LCOE tool.

Degradation

Solar photovoltaic (PV) power systems typically show a decline in maximum capacity as the systems age. On this worksheet, the user is prompted to enter a degradation factor for solar PV (suggested default is 1%). The degradation factor is expressed as an annual percentage reduction in maximum output. Degradation factors for all technologies other than solar PV are set to 0%.

Lifetime

On this worksheet, the user can enter unique power plant lifetime values for all 29 technologies. The LCOE values shown on subsequent worksheets are calculated based on plant lifetimes entered by the user as well as plant lifetimes contained in each data set.

Note that some data sets, such as AEO 2009 and EPA 2009, do not contain plant lifetime values. These data sets are used with the NEMS and IPM models, respectively, and these models do not use firm power plant lifetimes. In the case of NEMS and IPM, these models allow power plants to run until they are no longer economically viable – there is no pre-determined age limit. For data sets that do not have inherent plant lifetimes, the LCOE results are only computed using the lifetime values entered by the user.

LCOE Base Nom

This worksheet shows LCOE values calculated with the data entered on previous worksheets. The LCOE values are calculated in nominal dollars for the technologies in all data sets plus the user defined data set.

LCOE values are not calculated if a particular technology is not represented in a specific data set. If a technology is represented in a specific data set, but there is no pre-determined life, the LCOE results will only be reported for the lifetime entered by the user.

LCOE Base Real

This worksheet makes the same calculations as the previous worksheet. However, results are reported in real dollars (previous worksheet is based on nominal dollars).

Cost Contribution

This worksheet and the Cost Adjustments worksheet (see next section) are used to evaluate the impact on LCOE values as a result of changes in cost components that contribute to overnight capital costs. The overnight capital cost components that can be adjusted are shown in Table 56.

Table 56. Overnight Capital Cost Components

Overnight Capital Cost Components
Concrete
Steel
Other Onsite Materials
Equipment (major pieces delivered to site)
Labor
Other Cost Components

On the Cost Contributions worksheet, default values are provided for the contribution of each cost component to overnight capital costs for each of the 29 technologies included in the LCOE tool. The user can modify the cost contributions if desired. References used to estimate contributions to capital costs are shown below

5.1.16 References for Estimating Capital Cost Contributions

Energy Information Administration (EIA), Assumptions to AEO 2009, Report # DOE/EIA-0554, March 2009.

Engineering News Record, http://enr.construction.com/economics/default.asp, accessed December 18, 2009.

Hance, C. N., Factors Affecting Costs of Geothermal Power Development, prepared by Geothermal Energy Association, prepared for the U.S. Department of Energy, August 2005.

Mahjouri, F., and A. Nunez, The Relative Cost of Solar Thermal Collector Installations, http://www.thermomax.com/.

Meier, P. J., Life-cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis, UWFDM-1181, Aug. 2002

NETL, Cost and Performance Baseline for Fossil Energy Plants, Report No. DOE/NETL-2007/1281, Vol. 1, August 2007 (revised).

NREL, Job and Economic Development Impact (JEDI) model, http://www.nrel.gov/analysis/jedi/, default data, accessed January 2010.

Peterson, P., Future of Nuclear Energy, U Cal Berkeley, Aug. 2005

Resource Dynamics Corporation, Assessment of DG Technology Applications, report prepared for Maine PUC, February 2001.

Spitzley, D. V., and G. A. Keoleian, Life Cycle Environmental and Economic Assessment of Willow Biomass Electricity: A Comparison with Other Renewable and Non-Renewable Sources, February 2005, CSS04-05R.

White, S. W. and G. L. Kulcinski, "Birth to Death" Analysis of the Energy Payback Ratio and CO2 Gas Emission Rates from Coal, Fission, Wind, and DT Fusion Electrical Power Plants, Fusion Technology Institute, Univ. of Wisconsin, UWFDM-1063, Feb. 1999

White, S. W. and G. L. Kulcinski, Net Energy Payback and CO2 Emissions from Wind-Generated Electricity in the Midwest, Fusion Technology Institute, Univ. of Wisconsin, UWFDM-1092, Dec. 1998

Wiser, R., G. Barbose, and C. Peterman, Tracking the Sun, LBNL-1516e, February 2009.

The LCOE tool does allow for an interaction between steel prices and equipment prices. On the Cost Contribution worksheet, the estimated fraction of equipment costs attributed to steel – based on all equipment delivered to the construction site – is shown. The default factors shown for each of the 29 technologies can be modified. Data sources for estimating the cost contribution of steel to power generation technologies were scarce. The estimates in the spreadsheet should be regarded as rough approximations only.

Cost Adj

This worksheet is used to evaluate the impact of changes to the six overnight capital cost components shown in Table 56. In addition to the six capital cost components, the user can adjust learning rates as well as three factors that apply only to the AEO data set (metal and metal products PPI, technology optimism, and project contingency). On this sheet, the user provides estimated changes (expressed as a percent), and based on these estimates the overnight capital costs in all data sets are adjusted by the same percentage levels.

LCOE Adj Nom

This worksheet shows the baseline (before) LCOE values and the adjusted (after) LCOE values reported in nominal dollars. Like the "LCOE (baseline)" worksheet, LCOE results are not reported for technologies not contained in a particular data set, or for technologies that are included but do not have a pre-determined life.

LCOE Adj Real

This worksheet is comparable to the previous worksheet, but the LCOE values are reported in real dollars.

LCOE Comp Nom

This worksheet compares the baseline and adjusted LCOE results in nominal dollars.

LCOE Comp Real

This worksheet compares the baseline and adjusted LCOE results in real dollars.

Methodology

This worksheet contains the LCOE equations.

Calculations

The LCOE methodology is copied from the Methodology worksheet to this worksheet for all calculations. As calculations are completed, the results are transferred using macros to the respective results tables. For example, the tables contained in the LCOE (baseline), LCOE (adj, nom), and LCOE (adj, real) worksheets are populated dynamically as the calculations are completed.

Data Set Worksheets (multiple sheets)

These worksheets contain information needed to compute LCOE results. There are six worksheets – one for each data set.

User Defined

This worksheet is used to create a customized data set with up to 29 unique power generation technologies.

Summary Tables and Charts

Following the "User Defined" worksheet, there are several charts and tables that summarize results for 11 key technologies as shown in Table 57.

Table 57. Eleven Technologies Included in Summary

Technology
Coal
IGCC
Combustion Turbine
Combined Cycle
Nuclear
Biomass
Geothermal (hydrothermal)
Wind (onshore)
Wind (offshore)
Solar Thermal
PV

Appendix H. GDP Index

Table 58. GDP Index

Year	Relative GDP Values (2000 = 1)	(2007 =1)
1990	0.816	0.681
1991	0.844	0.705
1992	0.864	0.721
1993	0.884	0.738
1994	0.903	0.753
1995	0.921	0.769
1996	0.939	0.783
1997	0.954	0.796
1998	0.965	0.805
1999	0.979	0.817
2000	1.000	0.835
2001	1.024	0.855
2002	1.042	0.870
2003	1.064	0.888
2004	1.095	0.914
2005	1.130	0.943
2006	1.167	0.974
2007	1.198	1.000
2008	1.225	1.022
2009	1.237	1.032
2010	1.243	1.038
2011	1.258	1.050
2012	1.274	1.063
2013	1.297	1.082
2014	1.324	1.105
2015	1.354	1.130
2016	1.385	1.156
2017	1.417	1.182
2018	1.450	1.210
2019	1.484	1.239
2020	1.521	1.270

Source: The 1990 through 2009 values are based on data from the U.S. Department of Commerce, Bureau of Economic Analysis. The 2010 through 2020 values are based on data from EIA’s 2009 Annual Energy Outlook.

Appendix I. LCOE Results

Table 59. LCOE Results, 2015

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
AEO 2009	Coal	$23	$8	$19	$49	46%	16%	38%	0.50	0.30
GPRA 2009	Coal								0.50	0.30
NREL-SEAC 2008	Coal	$25	$7	$19	$50	49%	13%	38%	0.50	0.30
MiniCAM	Coal	$19	$9	$18	$46	41%	20%	40%	0.50	0.30
EPA 2009	Coal	$23	$8	$19	$50	46%	16%	38%	0.50	0.30
MERGE 2009	Coal	$29	$23	$18	$70	41%	32%	26%	0.50	0.30
`AEO 2009	IGCC	$28	$8	$17	$53	52%	15%	33%	0.50	0.20
GPRA 2009	IGCC								0.50	0.20
NREL-SEAC 2008	IGCC	$35	$9	$19	$63	56%	15%	29%	0.50	0.20
MiniCAM	IGCC								0.50	0.20
EPA 2009	IGCC	$28	$8	$18	$54	52%	15%	34%	0.50	0.20
MERGE 2009	IGCC	$35	$24	$18	$77	45%	32%	24%	0.50	0.20
AEO 2009	Combustion Turbine	$7	$4	$50	$61	11%	7%	82%	0.75	0.10
GPRA 2009	Combustion Turbine								0.75	0.10
NREL-SEAC 2008	Combustion Turbine	$9	$4	$49	$62	15%	6%	79%	0.75	0.10
MiniCAM	Combustion Turbine	$53	$18	$49	$120	44%	15%	41%	0.75	0.10
EPA 2009	Combustion Turbine	$7	$4	$51	$63	11%	7%	82%	0.75	0.10
MERGE 2009	Combustion Turbine								0.75	0.10
AEO 2009	Combined Cycle	$11	$3	$37	$51	22%	7%	71%	0.60	0.15
GPRA 2009	Combined Cycle								0.60	0.15
NREL-SEAC 2008	Combined Cycle	$9	$5	$38	$52	18%	10%	72%	0.60	0.15
MiniCAM	Combined Cycle	$10	$4	$34	$48	20%	8%	71%	0.60	0.15
EPA 2009	Combined Cycle	$11	$3	$37	$52	22%	7%	72%	0.60	0.15

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
MERGE 2009	Combined Cycle	$11	$7	$40	$58	18%	12%	69%	0.60	0.15
AEO 2009	Nuclear	$42	$12	$10	$64	66%	18%	16%	0.50	0.30
GPRA 2009	Nuclear								0.50	0.30
NREL-SEAC 2008	Nuclear	$41	$12	$10	$63	65%	19%	16%	0.50	0.30
MiniCAM	Nuclear	$31	$11	$10	$51	60%	21%	19%	0.50	0.30
EPA 2009	Nuclear								0.50	0.30
MERGE 2009	Nuclear	$59	$32	$10	$100	59%	32%	10%	0.50	0.30
AEO 2009	Biomass	$40	$15	$18	$73	55%	21%	24%	0.50	0.30
GPRA 2009	Biomass								0.50	0.30
NREL-SEAC 2008	Biomass	$31	$20	$29	$80	39%	25%	36%	0.50	0.30
MiniCAM	Biomass	$24	$10	$20	$54	44%	19%	37%	0.50	0.30
EPA 2009	Biomass	$40	$15	$20	$75	54%	20%	26%	0.50	0.30
MERGE 2009	Biomass	$38	$28	$25	$91	42%	31%	27%	0.50	0.30
AEO 2009	Geothermal (HT)	$61	$20	$0	$81	75%	25%	0%	0.20	0.40
GPRA 2009	Geothermal (HT)	$56	$14	$0	$70	80%	20%	0%	0.20	0.40
NREL-SEAC 2008	Geothermal (HT)	$43	$23	$0	$66	65%	35%	0%	0.20	0.40
MiniCAM	Geothermal (HT)	$35	$11	$0	$45	77%	23%	0%	0.20	0.40
EPA 2009	Geothermal (HT)	$130	$23	$0	$154	85%	15%	0%	0.20	0.40
MERGE 2009	Geothermal (HT)								0.20	0.40
AEO 2009	Wind (onshore)	$58	$8	$0	$66	87%	13%	0%	0.70	0.10
GPRA 2009	Wind (onshore)	$31	$6	$0	$38	83%	17%	0%	0.70	0.10
NREL-SEAC 2008	Wind (onshore)	$43	$8	$0	$51	84%	16%	0%	0.70	0.10
MiniCAM	Wind (onshore)	$32	$9	$0	$41	78%	22%	0%	0.70	0.10
EPA 2009	Wind (onshore)	$55	$9	$0	$64	86%	14%	0%	0.70	0.10
MERGE 2009	Wind (onshore)	$74	$44	$0	$118	63%	37%	0%	0.70	0.10
AEO 2009	Wind (offshore)	$112	$25	$0	$136	82%	18%	0%	0.70	0.10
GPRA 2009	Wind (offshore)	$55	$35	$0	$90	61%	39%	0%	0.70	0.10

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
NREL-SEAC 2008	Wind (offshore)	$57	$20	$0	$77	74%	26%	0%	0.70	0.10
MiniCAM	Wind (offshore)								0.70	0.10
EPA 2009	Wind (offshore)								0.70	0.10
MERGE 2009	Wind (offshore)								0.70	0.10
AEO 2009	Solar Thermal (CSP)	$153	$20	$0	$174	88%	12%	0%	0.50	0.30
GPRA 2009	Solar Thermal (CSP)	$97	$13	$0	$110	88%	12%	0%	0.50	0.30
NREL-SEAC 2008	Solar Thermal (CSP)	$138	$17	$0	$155	89%	11%	0%	0.50	0.30
MiniCAM	Solar Thermal (CSP)								0.50	0.30
EPA 2009	Solar Thermal (CSP)	$130	$18	$0	$148	88%	12%	0%	0.50	0.30
MERGE 2009	Solar Thermal (CSP)	$208	$111	$0	$319	65%	35%	0%	0.50	0.30
AEO 2009	PV	$290	$6	$0	$297	98%	2%	0%	0.60	0.10
GPRA 2009	PV	$109	$3	$0	$112	98%	2%	0%	0.60	0.10
NREL-SEAC 2008	PV	$140	$6	$0	$146	96%	4%	0%	0.60	0.10
MiniCAM	PV	$279	$28	$0	$307	91%	9%	0%	0.60	0.10
EPA 2009	PV	$255	$6	$0	$261	98%	2%	0%	0.60	0.10
MERGE 2009	PV	$319	$179	$0	$498	64%	36%	0%	0.60	0.10

Table 60. LCOE Results, 2030

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
AEO 2009	Coal	$17	$8	$20	$45	38%	18%	44%	0.50	0.30
GPRA 2009	Coal								0.50	0.30
NREL-SEAC 2008	Coal	$25	$7	$20	$52	48%	13%	40%	0.50	0.30
MiniCAM	Coal	$18	$9	$20	$46	39%	19%	42%	0.50	0.30
EPA 2009	Coal	$19	$8	$21	$48	40%	17%	44%	0.50	0.30
MERGE 2009	Coal	$29	$23	$20	$72	40%	31%	28%	0.50	0.30
`AEO 2009	IGCC	$20	$8	$17	$45	45%	18%	38%	0.50	0.20
GPRA 2009	IGCC								0.50	0.20
NREL-SEAC 2008	IGCC	$35	$9	$20	$64	55%	15%	31%	0.50	0.20
MiniCAM	IGCC	$22	$9	$18	$48	45%	18%	37%	0.50	0.20
EPA 2009	IGCC	$23	$8	$20	$51	45%	16%	39%	0.50	0.20
MERGE 2009	IGCC	$35	$24	$20	$79	43%	31%	26%	0.50	0.20
AEO 2009	Combustion Turbine	$5	$4	$52	$62	8%	7%	85%	0.75	0.10
GPRA 2009	Combustion Turbine								0.75	0.10
NREL-SEAC 2008	Combustion Turbine	$9	$4	$55	$68	14%	6%	81%	0.75	0.10
MiniCAM	Combustion Turbine	$52	$17	$54	$122	42%	14%	44%	0.75	0.10
EPA 2009	Combustion Turbine	$6	$4	$57	$67	8%	7%	85%	0.75	0.10
MERGE 2009	Combustion Turbine								0.75	0.10
AEO 2009	Combined Cycle	$8	$3	$39	$50	16%	7%	77%	0.60	0.15
GPRA 2009	Combined Cycle								0.60	0.15
NREL-SEAC 2008	Combined Cycle	$9	$5	$42	$57	17%	9%	75%	0.60	0.15
MiniCAM	Combined Cycle	$9	$4	$36	$49	18%	8%	74%	0.60	0.15
EPA 2009	Combined Cycle	$9	$3	$41	$54	17%	6%	77%	0.60	0.15
MERGE 2009	Combined Cycle	$11	$8	$39	$57	19%	14%	67%	0.60	0.15
AEO 2009	Nuclear	$29	$12	$13	$53	54%	22%	24%	0.50	0.30

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
GPRA 2009	Nuclear								0.50	0.30
NREL-SEAC 2008	Nuclear	$38	$12	$13	$63	60%	19%	21%	0.50	0.30
MiniCAM	Nuclear	$30	$11	$12	$53	57%	20%	23%	0.50	0.30
EPA 2009	Nuclear	$38	$12	$13	$63	61%	19%	21%	0.50	0.30
MERGE 2009	Nuclear	$50	$28	$13	$91	55%	31%	14%	0.50	0.30
AEO 2009	Biomass	$27	$15	$17	$58	46%	26%	29%	0.50	0.30
GPRA 2009	Biomass								0.50	0.30
NREL-SEAC 2008	Biomass	$31	$20	$31	$82	38%	24%	38%	0.50	0.30
MiniCAM	Biomass	$23	$10	$19	$52	45%	19%	37%	0.50	0.30
EPA 2009	Biomass	$36	$15	$21	$71	50%	21%	29%	0.50	0.30
MERGE 2009	Biomass	$38	$22	$26	$86	44%	25%	30%	0.50	0.30
AEO 2009	Geothermal (HT)	$43	$20	$0	$63	68%	32%	0%	0.20	0.40
GPRA 2009	Geothermal (HT)	$51	$13	$0	$64	80%	20%	0%	0.20	0.40
NREL-SEAC 2008	Geothermal (HT)	$43	$23	$0	$66	65%	35%	0%	0.20	0.40
MiniCAM	Geothermal (HT)	$33	$10	$0	$43	77%	23%	0%	0.20	0.40
EPA 2009	Geothermal (HT)	$130	$23	$0	$154	85%	15%	0%	0.20	0.40
MERGE 2009	Geothermal (HT)								0.20	0.40
AEO 2009	Wind (onshore)	$45	$8	$0	$54	84%	16%	0%	0.70	0.10
GPRA 2009	Wind (onshore)	$25	$5	$0	$30	84%	16%	0%	0.70	0.10
NREL-SEAC 2008	Wind (onshore)	$38	$7	$0	$45	84%	16%	0%	0.70	0.10
MiniCAM	Wind (onshore)	$28	$8	$0	$35	79%	21%	0%	0.70	0.10
EPA 2009	Wind (onshore)	$55	$9	$0	$64	86%	14%	0%	0.70	0.10
MERGE 2009	Wind (onshore)	$74	$36	$0	$110	67%	33%	0%	0.70	0.10
AEO 2009	Wind (offshore)	$79	$25	$0	$104	76%	24%	0%	0.70	0.10
GPRA 2009	Wind (offshore)	$35	$13	$0	$49	73%	27%	0%	0.70	0.10
NREL-SEAC 2008	Wind (offshore)	$52	$15	$0	$67	78%	22%	0%	0.70	0.10
MiniCAM	Wind (offshore)								0.70	0.10

Data Set	Technology	Baseline Costs							Contribution to Capital (%)	
		Cost Breakdown ($/MWh)			LCOE	Cost Breakdown (%)				
		Capital	O&M	Fuel	($/MWh)	Capital	O&M	Fuel	Equipment	Labor
EPA 2009	Wind (offshore)								0.70	0.10
MERGE 2009	Wind (offshore)								0.70	0.10
AEO 2009	Solar Thermal (CSP)	$95	$20	$0	$115	82%	18%	0%	0.50	0.30
GPRA 2009	Solar Thermal (CSP)	$37	$5	$0	$42	88%	12%	0%	0.50	0.30
NREL-SEAC 2008	Solar Thermal (CSP)	$138	$17	$0	$155	89%	11%	0%	0.50	0.30
MiniCAM	Solar Thermal (CSP)	$49	$5	$0	$54	90%	10%	0%	0.50	0.30
EPA 2009	Solar Thermal (CSP)	$130	$18	$0	$148	88%	12%	0%	0.50	0.30
MERGE 2009	Solar Thermal (CSP)	$208	$111	$0	$319	65%	35%	0%	0.50	0.30
AEO 2009	PV	$182	$6	$0	$189	97%	3%	0%	0.60	0.10
GPRA 2009	PV	$59	$1	$0	$60	98%	2%	0%	0.60	0.10
NREL-SEAC 2008	PV	$84	$3	$0	$87	96%	4%	0%	0.60	0.10
MiniCAM	PV	$155	$14	$0	$169	92%	8%	0%	0.60	0.10
EPA 2009	PV	$255	$6	$0	$261	98%	2%	0%	0.60	0.10
MERGE 2009	PV	$319	$179	$0	$498	64%	36%	0%	0.60	0.10

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. REPORT DATE *(DD-MM-YYYY)*	2. REPORT TYPE	3. DATES COVERED *(From - To)*
November 2010	Subcontract Report	

4. TITLE AND SUBTITLE
Cost and Performance Assumptions for Modeling Electricity Generation Technologies

5a. CONTRACT NUMBER
DE-AC36-08-GO28308

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

6. AUTHOR(S)
R. Tidball, J. Bluestein, N. Rodriguez, and S. Knoke

5d. PROJECT NUMBER
NREL/SR-6A20-48595

5e. TASK NUMBER
SAO9.2502

5f. WORK UNIT NUMBER

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
ICF International
Fairfax, VA

8. PERFORMING ORGANIZATION REPORT NUMBER
KACX-8-88312-04

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

10. SPONSOR/MONITOR'S ACRONYM(S)
NREL

11. SPONSORING/MONITORING AGENCY REPORT NUMBER
NREL/SR-6A20-48595

12. DISTRIBUTION AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

13. SUPPLEMENTARY NOTES
NREL Technical Monitor: Jordan Macknick

14. ABSTRACT *(Maximum 200 Words)*
The goal of this project was to compare and contrast utility scale power plant characteristics used in data sets that support energy market models. Characteristics include both technology cost and technology performance projections to the year 2050. Cost parameters include installed capital costs and operation and maintenance (O&M) costs. Performance parameters include plant size, heat rate, capacity factor or availability factor, and plant lifetime. Conventional, renewable, and emerging electricity generating technologies were considered. Six data sets, each associated with a different model, were selected. Two of the data sets represent modeled results, not direct model inputs. These two data sets include cost and performance improvements that result from increased deployment as well as resulting capacity factors estimated from particular model runs; other data sets represent model input data. For the technologies contained in each data set, the levelized cost of energy (LCOE) was also evaluated, according to published cost, performance, and fuel assumptions.

15. SUBJECT TERMS
cost and performance; electricity generation; power plants; utility scale; data; model inputs; model results; learning by doing; capacity factors; levelized cost of energy (LCOE); NEMS; National Energy Modeling System; EIA; Energy Information Administration; MARKAL; Market Allocation International Energy Agency; ReEDS; Regional Energy Deployment System; MiniCAM; Mini Climate Assessment Model; IPM; Integrated Planning Model; MERGE; Model for Estimating the Regional and Global Effects of Greenhouse Gas Reductions

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT	b. ABSTRACT	c. THIS PAGE			
Unclassified	Unclassified	Unclassified	UL		19b. TELEPHONE NUMBER *(Include area code)*