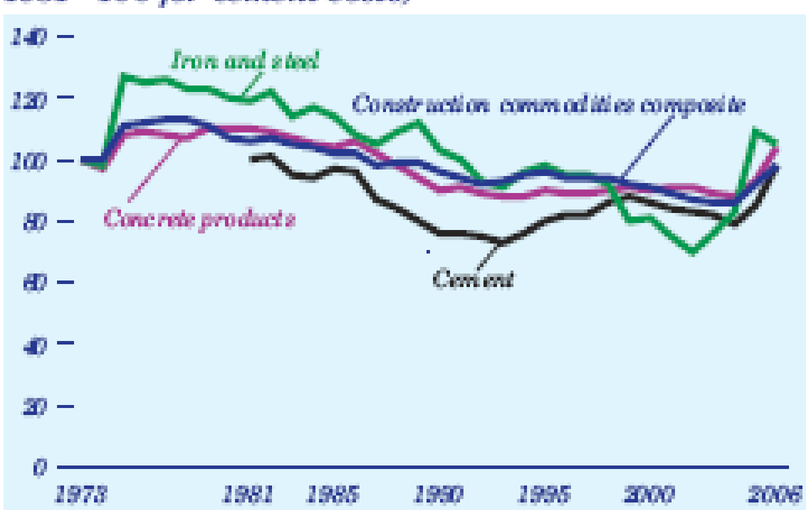
Technical Appendix for 2007 UCS National RPS Analysis

Costs and performance assumptions for new power plants

This section describes the changes we made to the costs and performance assumptions for new electric generating technologies included in the National Energy Modeling System (NEMS). We made these changes to incorporate the results of new research and data from actual and proposed projects and to more accurately reflect the recent cost increases in equipment, materials, and labor that are not included in EIA's assumptions.

The recent costs increases that are affecting power plants and other construction projects have been well documented, including by EIA. For example, EIA's Annual Energy Outlook 2007 report shows that after following a general downward trend from the 1970's through 2002, iron and steel prices increased by nearly 50 percent in real terms between 2002 and 2005 (and additional 22 percent through June 2006), construction materials increased by 21 percent or 7 percent per year on average over the same period, and cement and concrete prices have followed similar trends (see Figure). EIA also shows significant real escalation in the cost of oil and gas drilling and surface mining coal equipment costs, which has contributed to the recent increases in fuel prices.

Figure 11. Changes in construction commodity costs, 1973-2006 (constant dollar index, 1973=100; 1981=100 for cement costs)



The cost increases in construction materials, fuel, and labor have had a noticeable impact on the costs of building and operating power plants. After following a downward trend since the 1970's, the Handy-Whitman index for electric utility construction shows an average annual cost increase of 5 percent in real terms between 2003 and 2006, which is slightly lower than that of the overall construction cost index (see Figure). EIA claims this is largely due to the power plant construction boom between 2000 and 2004, when an average of 38 GW per year of mostly natural gas power plant capacity was added in the U.S.[1]

Similar indices reported by the Electric Power Research Institute show an increase in construction costs for large engineered projects of approximately 4 percent per year from 2003 to 2006 in real terms (see Figure). A report prepared by the Brattle Group provides further support, showing that the cost of steam generation plant, transmission projects, and distribution equipment rose by 25 percent to 35 percent between January 2004 and January 2007.[2] These costs increases are evident in data from recently built and proposed projects covering a wide range of technologies, as shown in two request for proposals from Puget Sound Energy in 2004 and 2006 (see Figure) and in more detail in the sections below.

Figure 14. Changes in construction commodity costs and electric utility construction costs, 1973-2006 (constant dollar index, 1973=100)

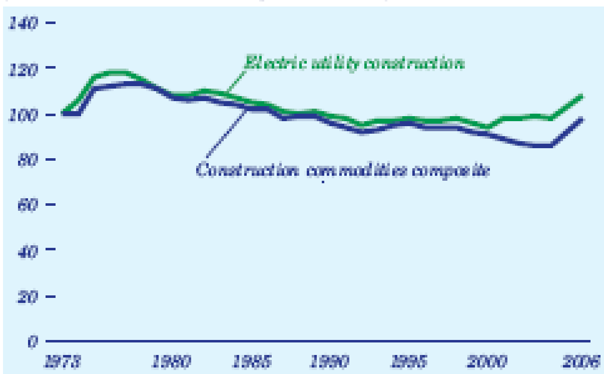
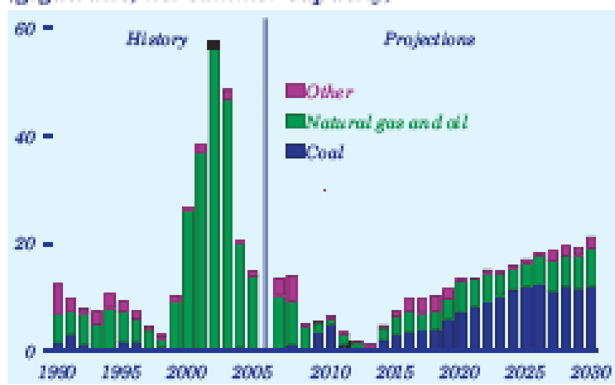
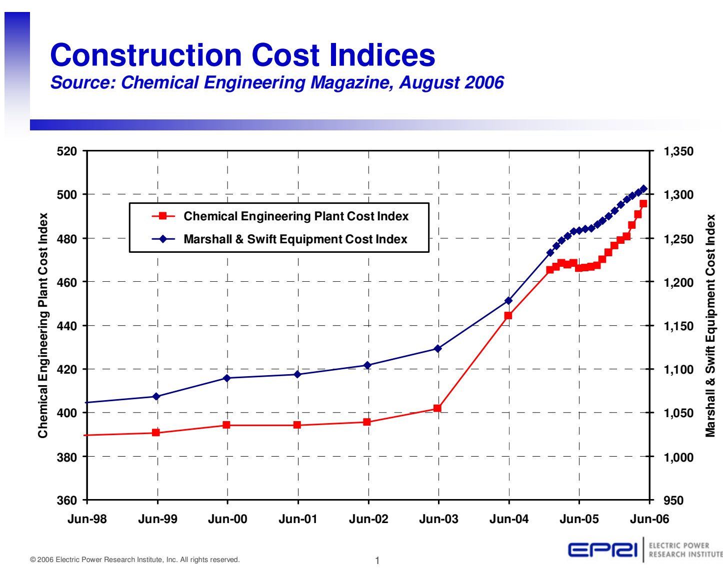


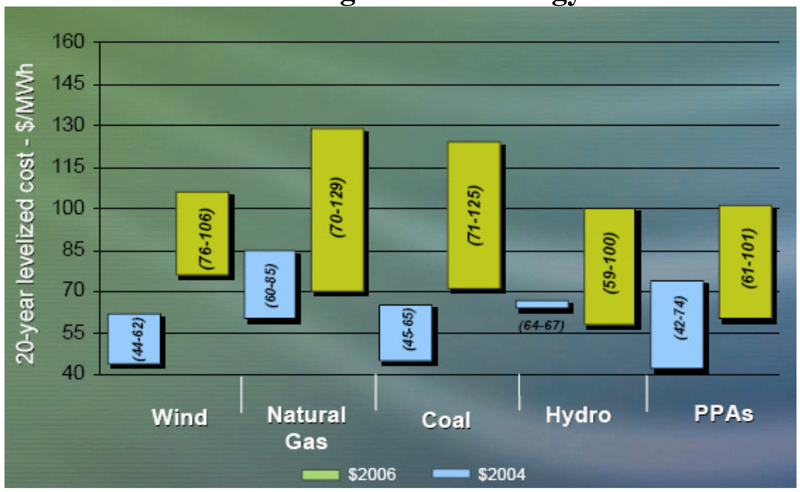
Figure 15. Additions to electricity generation capacity in the electric power sector, 1990-2030 (gigawatts, net summer capacity)





[1] For more information see EIA, Annual Energy Outlook 2007, pp. 36-41.
[2] Marc W. Chupka and Gregory Basheda, *Rising Utility Construction Costs: Sources and Impacts*, prepared by the Brattle Group for the Edison Foundation, September 2007.

Prices from Puget Sound Energy RFPs



Source: Puget Sound Energy IRPAG, powerpoint presentation, June 22, 2006.

While the recent increase in construction, materials, and labor costs for electric generating technologies is well-documented, there is considerable uncertainty about how long this trend will continue or whether costs will come back down and follow trends seen over the past few decades. This uncertainty is reflected in long-term cost projections from various electricity sector and technology experts. Some federal government agencies (e.g. EIA, NETL, and NREL), academic institutions (e.g. MIT), and industry groups (e.g. EPRI) that are frequently used as references for power plant costs have chosen not include the recent cost increases in either their short-term or long-term projections. For example, recent reports from EIA and MIT have assumed that the recent cost increases are the result of short-term supply constraints and that costs will likely revert back to long-term trends in the future. However, others sources such as Black & Veatch, a global engineering, consulting and power plant construction company, and Standard and Poors, tend to use more conservative assumptions that reflect the recent increases in costs seen for recent projects, and assume that costs will remain at higher levels over time.

Since both outcomes are plausible, we developed a range of assumptions to capture the uncertainty going forward under two scenarios. The "EIA case" assumes no changes to the assumptions used in the Annual Energy Outlook 2007 version of the National Energy Modeling System. These assumptions do not include the recent increase in construction, materials, and labor costs in either the short-term or the long-term. The "UCS case" does capture these cost increases by:

- using cost and performance assumptions for wind, coal, natural gas, and nuclear technologies developed by Black & Veatch as part of a broad stakeholder process for the U.S. Department of Energy's National Wind Collaborative.
- using costs and performance assumptions for solar, geothermal, and biomass technologies that are more in line with projections by the DOE's Office of Energy Efficiency and Renewable Energy and the National Renewable Energy Laboratory (NREL), and
- taking into account recent cost increases from actual conventional and renewable energy projects.

For each case, we made a concerted effort to adopt a consistent approach across all technologies. This is challenging given that different technologies are at various stages of maturity and commercial viability and some technologies are currently experiencing supply constraints due to high demand, while others are not. In addition, different technologies have different mixes and types of equipment, materials, and labor that result in higher or lower cost impacts than other technologies. We attempted to account for these differences in developing our assumptions, which are discussed in more detail below for each technology.

Unless otherwise noted below, both cases use EIA assumptions for financing costs, capacity factors, and fuel prices. These variables are all calculated within the model. Fuel prices vary somewhat based on the supply and demand for different types of fuel under different scenarios. Capacity factors also vary based on the relative economics and operating characteristics of different electricity technologies.

In addition, we evaluated the contribution made by states with renewable electricity standards that fully achieve their annual targets to a national renewable standard. In AEO 2007, EIA assumed that states will only achieve a faction of their annual targets. Our evaluation also includes several states that adopted new or higher standards over the past year that were not included in AEO 2007.

Below, we describe the cost and performance assumptions used for electric generating technologies in the UCS case and compare them to the assumptions from the EIA case.

CONVENTIONAL TECHNOLOGIES

Supercritical Pulverized Coal

Capital costs

Overnight capital costs for the UCS case are based on Black and Veatch's (B&V) projections for the DOE National Wind Collaborative and data from actual projects. B&V claims their projections went through a rigorous internal review process and are based on data from dozens of recent projects that are either under construction or going through the regulatory approval process. B&V's projections are consistent with data collected by UCS and Synapse Energy Economics for more than a dozen actual projects, with proposed online years between 2011 and 2014. In the past year, at least six proposed projects have announced capital cost increases of 30-80 percent compared to their original estimates. These projects have significantly higher costs than the generation of plants that have been recently built or are currently under construction (e.g. Weston 4, Nebraska City 2, and Council Bluffs).

As shown in the figure below, the capital costs of actual projects are significantly higher than EIA's most recent estimate and several other commonly referenced sources (MIT, EPRI, EPA, and NETL). It appears that these sources are relying on data from plant design studies completed before the recent run-up in construction, equipment, material, and labor costs. For example, as discussed in the MIT Future of Coal study:

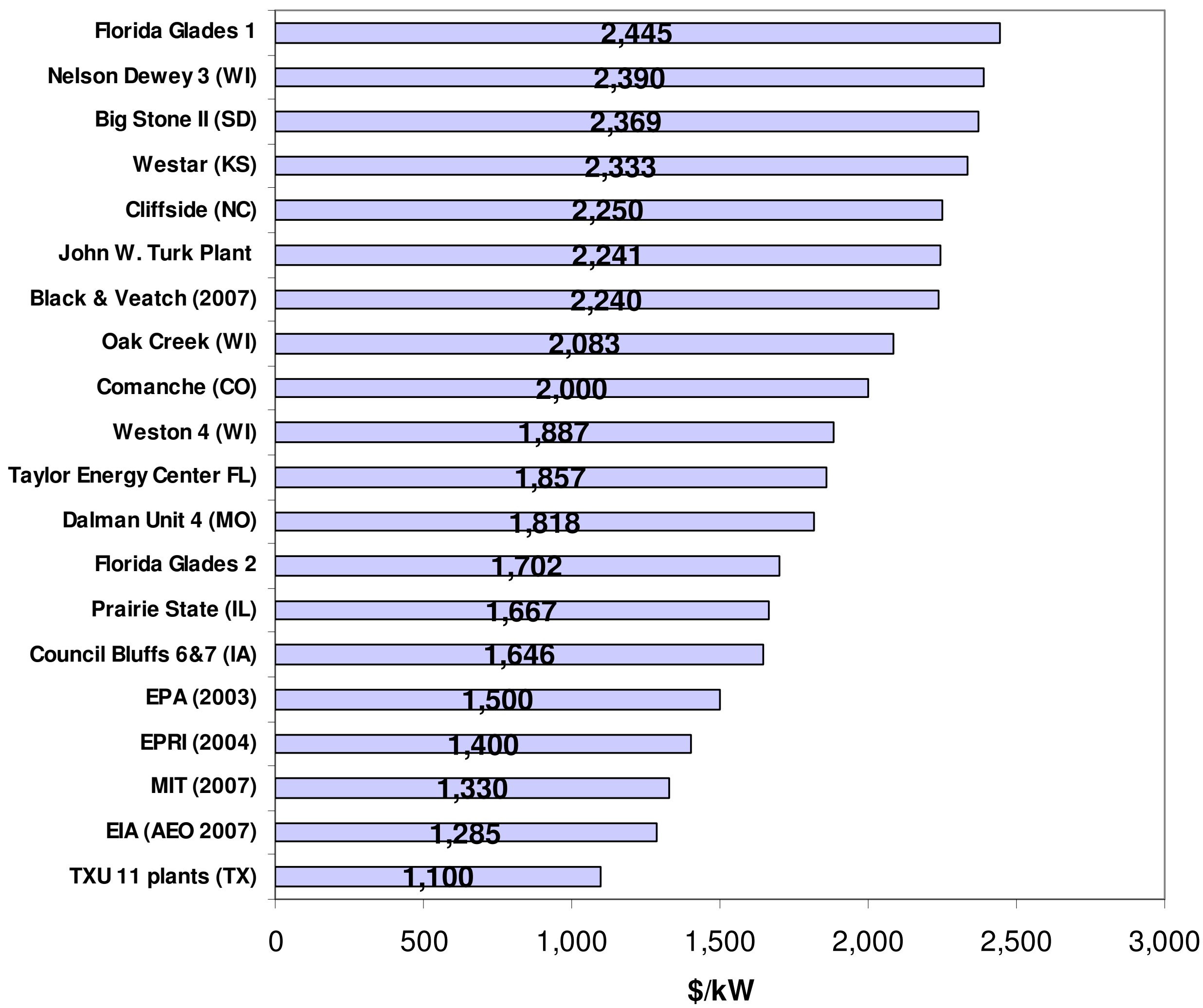
> Total plant costs…were developed during a period of price stability [2000-2004]…These costs and the deltas among them were well vetted, broadly accepted, and remain valid in comparing different generation technologies. However, significant cost inflation from 2004 levels due to increases in engineering and construction costs, including labor, steel, concrete, and other consumables used for power plant construction, has been between 25 and 30 percent.

The MIT study goes on to say that that they were not able to get firm data on how these cost increases will affect other technologies evaluated in the report so they decided not to include them. While they also claim that the assumptions may be reasonable for comparing the relative cost of different generating technologies, it is not clear that this is the case. For example, Black & Veatch's capital costs estimates are approximately 60-70 percent higher than MIT's and EIA's estimates, while B&V's capital cost estimates for wind power are only 11 percent higher than EIA's. B&V's assumptions for coal include owners costs of 20 percent and assume real escalation until 2015, which could explain some, but not all, of the higher cost. Most of the coal plants illustrated in the figure below also include owners costs and real escalation.

Table 1. Supercritical Pulverized Coal Assumptions

	UCS Case	EIA (2005$)
Overnight capital cost (2005$/kW)	$2,115 (2010) $2,173 (2015)	$1,285 (2010) $1,268 (2015)
Real Escalation	0.5% per year from 2005 to 2015	None
Learning	None, mature technology	6% reduction by 2030 in AEO 2007 reference case
O&M (2005$)	$34.3/kW-yr fixed $1.6/MWh variable	$25.9/kW-yr fixed $4.3/MWh variable
Heat Rate (Btu/kWh)	9,200 in 2010 declining to 9,000 in 2020	8,783 in 2010 declining to 8,600 in 2019

Capital Costs for new pulverized coal plants (2006$/kW)



Coal IGCC

Capital costs

Reliable cost estimates for producing electricity from coal IGCC plants are very limited. No projects have been built in the US recently and only four projects have been demonstrated in the US in the 1990s, with mixed success. While coal gasification technology has been demonstrated fairly extensively in the industrial sector, the application of the technology for producing electricity on a large scale is limited to a handful of demonstration plants built in the US in the 1980s and 1990s.

As of October, 2007, 33 coal IGCC projects have been proposed in the US, according to the DOE National Energy Technology Laboratory (NETL). The cost and performance data for most of these projects is not publicly available and is based largely on optimistic estimates from vendors vs. actual installations. While we were able to obtain data from 6 proposed projects, only four of these projects included data on capital costs. Out of these four data points, the cost for the proposed Mesaba unit 1 is likely to be the most accurate as it recently went through an extensive review process and contested case proceeding before the Minnesota PUC. This project has an estimated capital cost of over $3,000 including EPC and owners costs, with a total cost of nearly $3,600/kW including financing, transmission, and other site costs.

By comparison, B&V assumes overnight capital costs of $2,840/kW (2006$) for a plant with an in-service date of 2010 and Standard and Poors (S&P) assumes capital costs of $2,795/kW for using eastern coal and $2,925/kW for using western coal from the Powder River Basin. Other commonly referred to sources such as EIA, MIT, NETL, and IPCC assume capital costs for IGCC ranging from $1,326-$1,977/kW. As indicated above, these sources do not reflect all of the recent escalation in costs, do not include owners costs, and in some cases (e.g. MIT) assume some cost reductions for the nth of a kind plant.

Therefore, we conservatively use B&V's projections, which are reasonably consistent with the estimates from S&P. We believe B&V's assumptions are somewhat optimistic as they are below the $3,000/kW estimated cost of the limited number of IGCC projects. B&V also assume capital costs will stayed fixed over time, while EIA's AEO 2007 reference case includes real capital cost reductions of 15% by 2030. (Note: larger cost reductions are possible using EIA's assumptions under scenarios that include additional IGCC capacity additions).

The S&P report claims that IGCC has "substantially higher construction and start-up risks compared with traditional pulverized coal plants." They also conclude that federal support through loan guarantees or tax credits will be needed to launch the first few IGCC units.

Capacity Factor
The UCS case assumes a maximum capacity factor of 80 percent based on B&V and S&P estimates compared to a maximum capacity of 85 percent under EIA's assumptions from AEO2007. According to S&P, while major IGCC suppliers have claimed readiness and assume capacity factors of 85%, no EPC contractor has offered a fixed price turnkey contract with liquidated damages for cost, time, and performance.

Lead-time
The UCS case assumes a construction lead-time of five years based on Black & Veatch data compared to EIA's assumption of four years.

Levelized costs
Using these assumptions, along with EIA's assumptions for fuel costs and financing, results in a all-in levelized cost of electricity of roughly $86/MWh for the UCS case and $48/MWh for the EIA case for an IGCC plant installed in the year 2015. We believe these costs are optimistic even for the UCS case, as they are below the low end of the range of costs from recently proposed projects. For example, an NRG proposal to shut down two units at its Indian River plant in Delaware and convert the site to a 600 MW IGCC plant ranked third behind a natural gas combined cycle plant and an offshore wind project, according to an evaluation completed by outside consultants for the Delaware Public Service Commission (New Energy Opportunities, 2007). The project was reported to have a levelized cost of $107/MWh in real 2005 dollars, not including carbon capture and storage.

Minnesota Department of Commerce testimony before the Minnesota PUC indicated that the Mesaba IGCC proposal in northern Minnesota would have a levelized cost of $96-131/MWh without transmission or carbon capture and storage and $155-190/MWh with transmission and CCS. MidAmerican Energy Holdings recently announced that it had received a reasonably firm contractual offer for an IGCC plant with carbon capture and storage in Wyoming with a levelized cost between $110 and $120/MWh, according to Standard and Poors (2007).

Table 2. Coal IGCC Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	2,756 (2010-2030)	1,421 (2010) 1,274 (2030)
Real Escalation	Included above for projects built in 2010	None
Learning	No reduction in capital costs, but heat rates are projected to decline	Different learning rates applied to different components. AEO 2007 reference cases includes 15% cost reduction by 2030
Capacity factor	80%	85%
O&M (2005$)	Fixed: $37/kW-yr Variable: $3.8/MWh	Fixed: $36.38/kW-yr Variable: $2.75/MWh
Heat Rate (Btu/kWh)	9,000 (2010) 8,580 (2030)	8,309 (2010) 7,200 (nth of a kind)
Lead time	5 years	4 years

Coal IGCC with CCS

For the UCS case, we added the incremental capital cost of CCS from EIA's assumptions to B&Vs cost estimates for IGCC (from the table above). EIA's incremental cost for CCS was in the range of values from four studies by MIT, IPCC, NETL, and S&P. We also assumed a higher initial heat rate than EIA based on the median value in a range of 6 estimates (by EIA, NETL, MIT, and S&P). Our assumptions for real escalation, financing, capacity factor, fuel costs, and lead times are the same as for IGCC.

Table 3. Coal IGCC w/CCS Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	3,376 (2010) 3,243 (2030)	2,110 (2010) 1,762 (2030)
Real Escalation	Included for projects built in 2010	None
Learning	Includes EIA's assumed learning for CCS and heat rate improvements.	Different learning rates applied to different system components. AEO 2007 reference cases includes 16% cost reduction by 2030.
Capacity factor	80%	85%
Fixed O&M (2005$/kW-yr)	EIA	42.8
Variable O&M (2005 mills//kWh)	EIA	4.2
Heat Rate (Btu/kWh)	10,720 (2010) 9,877 (2030)	9,397 (2010) 7,920 (nth of a kind)
Lead time	5 years	4 years

References (for PC and IGCC):
IPCC, *Special Report on Carbon Dioxide Capture and Storage*, 2005, http://www.ipcc.ch/activity/srccs/index.htm

Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

MIT, *The Future of Coal: Options for a Carbon Constrained World*, 2007.

NETL, *Tracking New Coal-Fired Power Plants*, powerpoint presentation, October 10, 2007.

NETL, *Cost and Performance Baseline for Fossil Energy Plants*, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report, DOE/NETL-2007/1281, May 2007.
Standard and Poors, "Which Power Generation Technologies Will Take the Lead in Response to Carbon Controls?" May 11, 2007.

Dr. Eilon Amit, Minnesota Department of Commerce, surrebuttal testimony on the Excelsior Energy Inc. proposed coal IGCC project, Minnesota Public Utilities Commission, Docket No. E6472/M-05-1993, November 9, 2006.

New Energy Opportunities, Inc., La Capra Associates, Inc, Merrimack Energy Group, Inc., and Edward L. Selgrade, Esq., *Report on Evaluation of Bids Submitted in Response to Delmarva Power and Light Company's RFP*. Prepared for the Deleware Public Service Commission for PSC Docket No. 06-241, February 21, 2007.

Natural gas combined cycle (NGCC)
For the UCS case, the cost and performance assumptions for new NGCC plants are based on Black & Veatch projections, which are based on data from actual projects, and data collected by the California Energy Commission (2007) for 19 plants installed in California from 2001 to 2006.

We made three adjustments to the costs in the CEC report. First, we subtracted out the cost of emission reduction credits, which are specific to California. Second, we reduced total overnight costs by 5.8 percent to reflect higher construction costs in California relative to the national average based on EIA's assumptions in NEMS. Third, we converted the capital and O&M costs from 2007 to 2005 dollars to make them consistent with the cost data from EIA and the other sources in this report.

Using these assumptions, overnight capital costs for advanced NGCC plants were estimated at $700/kW (2005$), which is slightly lower than B&V's estimate of approximately $750/kW. Standard and Poors also assumes a capital cost of $700/kW.

Table 4. Advanced Natural Gas Combined Cycle Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	$757	592
Real Escalation	Included in B&V and CEC near-term estimates, no real escalation assumed after this time	None
Learning	None	11% cost reduction in AEO 2007 reference case
Fixed O&M (2005$/kW-yr)	14.4	11
Variable O&M (2005 mills//kWh)	2.9	1.9
Heat Rate	6,870	6,647 in 2009

(Btu/kWh)		declining to 6,333
Lead time	3	3

Advanced NGCC with CCS plants

For the UCS case, we added the incremental capital cost of CCS from EIA's assumptions ($590/kW) to B&Vs cost estimates for advanced NGCC (from the table above). EIA's incremental cost for CCS was in the range of values from four studies (EIA, IPCC, NETL, S&P). We also assumed a higher initial heat rate than EIA by adding the difference between EIA's heat rates for advanced NGCC plants with and without CCS to B&V's assumed heat rate for advanced NGCC (in the table above). Our assumptions for learning, financing, capacity factor, fuel costs, and lead times are the same as for advanced NGCC plants without CCS.

Table 5. Advanced Natural Gas Combined Cycle with CCS Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	1,336 (2010) 1,219 (2030)	1,171 (2010) 994 (2030)
Real Escalation	Included in initial B&V 2005 estimates, no real escalation assumed after this time	None
Learning	No capital cost reductions, some increase in efficiency	11% cost reduction in AEO 2007 reference case
Fixed O&M (2005$/kW-yr)	EIA	18.7
Variable O&M (2005 mills//kWh)	EIA	2.8
Heat Rate (Btu/kWh)	8,675 (2010) 8,128 (2030)	8,349 (2010) 7,493 (2030)
Lead time	3	3

Conventional NGCC plants
For the UCS case, we use the CEC's estimate for conventional NGCC plants, which is also based on their survey of 19 plants installed in CA between 2001 and 2006.

Table 6. Conventional Natural Gas Combined Cycle Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	703	600 (2010) 568 (2030)
Real Escalation	Included in above	None
Learning	None, mature technology	6% cost reduction by 2030
Fixed O&M (2005$/kW-yr)	9.4 (CEC)	11.7
Variable O&M (2005 mills//kWh)	4.2 (CEC)	1.9
Heat Rate (Btu/kWh)	6,990	7,097 (2009) 6,800 (nth of a kind)
Lead time	3	3

References
California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Draft Staff Report, CEC-200-2007-011-SD, June 2007.

Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

Natural gas combustion turbines (NGCT)

Advanced NGCTs
The cost and performance assumptions for new advanced and conventional NGCT plants are based on projections from Black & Veatch (2007) and data collected by the California Energy Commission (2007) for 15 plants installed in California from 2001 to 2006.

References
California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Draft Staff Report, CEC-200-2007-011-SD, June 2007.

Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

Table 7. Advanced Natural Gas Combustion Turbine Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	606 (2005) 728 (2010-2030)	396 (2010) 340 (2030)
Real Escalation	Included in plants built through 2010	None
Learning		15% cost reduction by 2030
Fixed O&M (2005$/kW-yr)	6.4	9.9
Variable O&M (2005 mills//kWh)	2.7	3.0
Heat Rate (Btu/kWh)	9,104 declining to 8,900 for nth of a kind plant	9,104 declining to 8,550 for nth of a kind plant
Lead time	2	2

Advanced Nuclear

For the UCS case, we used cost and performance assumptions from Black & Veatch (2007) and a recent report from the Keystone Center that was developed with input from a broad and diverse stakeholder group, including the nuclear industry.[3] As shown in Table 8 below, the biggest differences between the UCS case and the EIA case are in overnight capital costs, learning, fixed O&M costs, and capacity factors. Overnight capital costs are based on estimates from B&V and are similar to the values from the Keystone report. Fixed O&M costs are based on the middle of the range of values reported in the Keystone report. Capacity factors are also assumed to be in the middle of the range of the current US fleet average of 90 percent and the historical fleet average of approximately 75 percent. All other variables are the same as or close to the values used by EIA.

Using these assumptions and EIA assumptions for financing and fuel costs, results in an all-in levelized cost of electricity of $95/MWh in the UCS case and $59.7/MWh in the EIA case for a plant installed in the year 2015. While the UCS case falls in the range of values in the Keystone report ($83/MWh to $111/MWh), we believe these costs are optimistic. We believe that nuclear plants could have higher capital costs, as well as higher fuel costs, decommissioning costs, and financing risk premiums than are reflected in EIA's assumptions.

[3] See Table 5 and Table 6, p. 42 of Keystone Center, *Nuclear Power Joint Fact-Finding*, June 2007.

Table 8. Advanced Nuclear Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	3,000 in 2014 2,850 in 2030	2,005 in 2014 1,742 in 2030
Real Escalation	Included in near-term B&V estimates	None
Learning	6% cost reduction between 2014 and 2030	--5% reduction per doubling for first 3 doublings --3% reduction per doubling for next 5 doublings --10% minimum learning by 2025
First on-line year	EIA	2014, assuming 2006 order date
Capacity factor	82.5%	90%
Fixed O&M (2005$/kW-yr)	110	63.9
Variable O&M (2005mills/kWh)	0.49	0.47
Heat Rate (Btu/kWh)	10,400	10,400
Lead time	6	6

<u>References</u>

Keystone Center, *Nuclear Power Joint Fact-Finding*, June 2007.

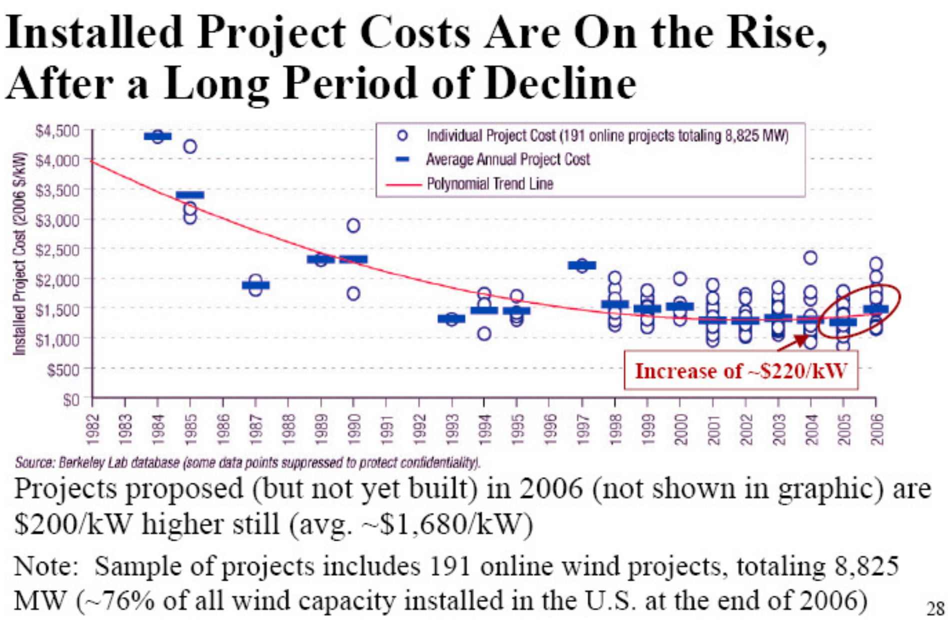
Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

RENEWABLE ENERGY TECHNOLOGIES

Wind--Onshore

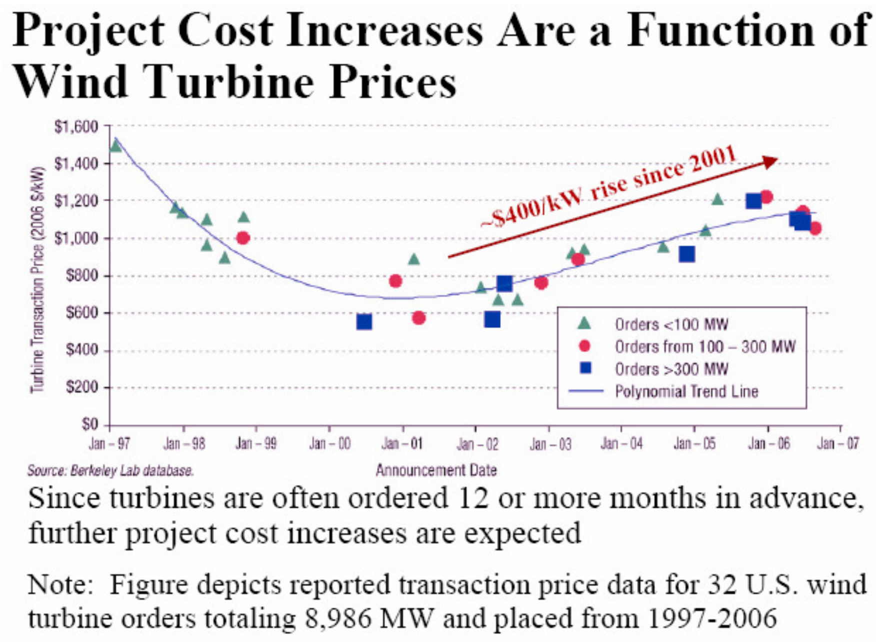
Capital Costs

For the UCS case, overnight capital cost estimates for 2005 through 2007 are based on estimates from a comprehensive database of 191 on-line wind projects in the US totaling 8,825 MW or 76% of the total installed wind capacity in the US at the end of 2006 (see Figure) and a sample of proposed projects, as reported in Wiser (2007a). These estimates include real escalation of 33 percent or $420/kW between 2005 and 2007. Most of this increase is due to an increase in wind turbine prices, which rose ~$400/kW between 2001 and the end of 2006. Since installed costs increased by $220/kW between 2005 and 2006, this suggests that the increase in wind turbine prices may not have completely flowed through to prices. This is evident in Wiser's estimated costs of $1,680/kW for 2007 based on the sample of proposed projects. The 2007 values are similar to Black & Veatch's estimated costs of $1,650/kW (2006$) for projects installed between 2005 and 2010 that were developed for the DOE National Wind Collaborative 20 percent Wind Vision study.



Source: Wiser, 2007a.

For the UCS case, we use the Black & Veatch projections (converted to 2005$), which assume capital costs will decline by 10 percent between 2010 and 2030 based on estimates developed by GE and Vestas for the Wind Vision study. A recent survey of wind turbine and component manufacturers shows that capital costs could decline even further (Wiser, 2007b). This survey showed that cost reductions of 15 percent to 22 percent may be possible under a more stable, long-term policy environment, such as a long-term PTC extension or a national RPS, that would facilitate an increase in domestic wind turbine manufacturing. It is also possible that the real escalation of wind turbine prices will continue to rise due to the continued high global demand for turbines. Anecdotal information reported by Wiser (2007a) shows that average turbine prices could reach $1,800/kW over the next few years.



Source: Wiser, 2007a.

We assume that many of the current supply constraints driving up wind turbine prices will ease in the next few years that will offset the real escalation in materials and labor costs affecting all technologies. There are at least three reasons for this. First, the recent run-up in wind capital costs is due in part to the short-term PTC cycle, which has greatly inhibited investment in manufacturing of wind turbines and components in the U.S. Much of the equipment is imported from manufacturers in countries such as Denmark, Germany, Spain, India, and even Vietnam (towers) to meet the growing demand for wind turbines in the U.S. Not only does this result in high transportation costs, but the weak dollar relative to the euro also raises costs relative to manufacturing the equipment in the U.S.

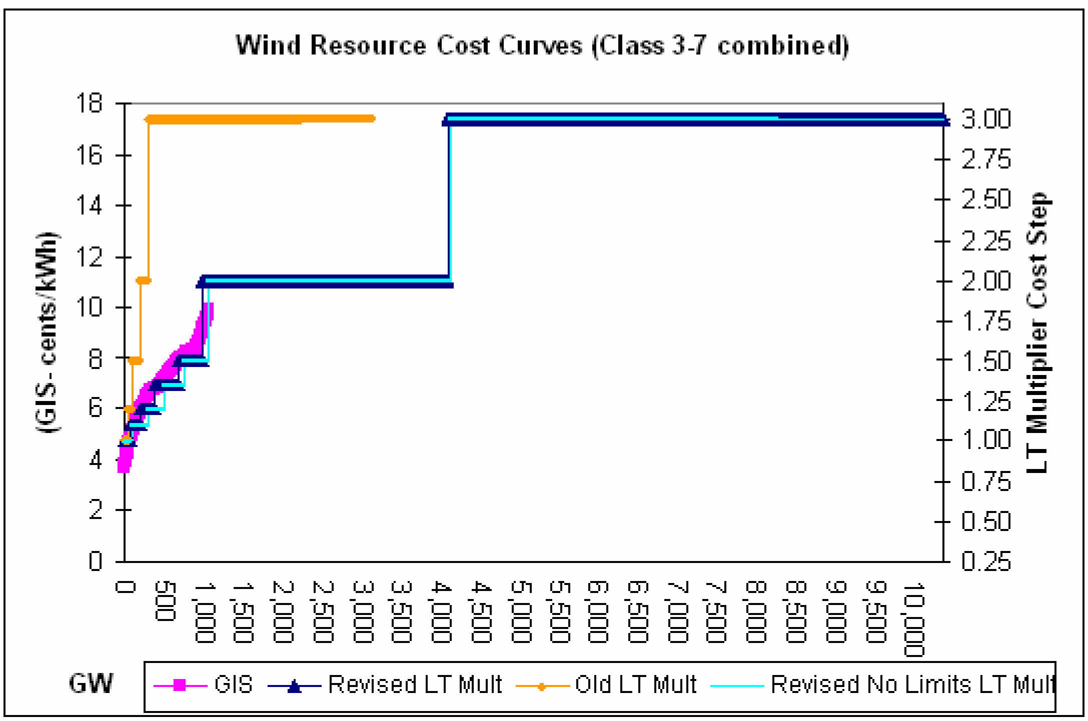
This situation is changing, however, as several major wind manufacturers have recently built plants or announced plans to build plants in the U.S. For example, manufacturing plants have recently been built or announced in Iowa (Clipper, Siemens, and Acconia), Minnesota (Suzulon), Pennsylvania (Gamesa), Colorado (Vestas), Texas (Mitsubishi), and many other states across the U.S. Many industry experts believe that this will help ease supply constraints and put downward pressure on prices in the next few years.

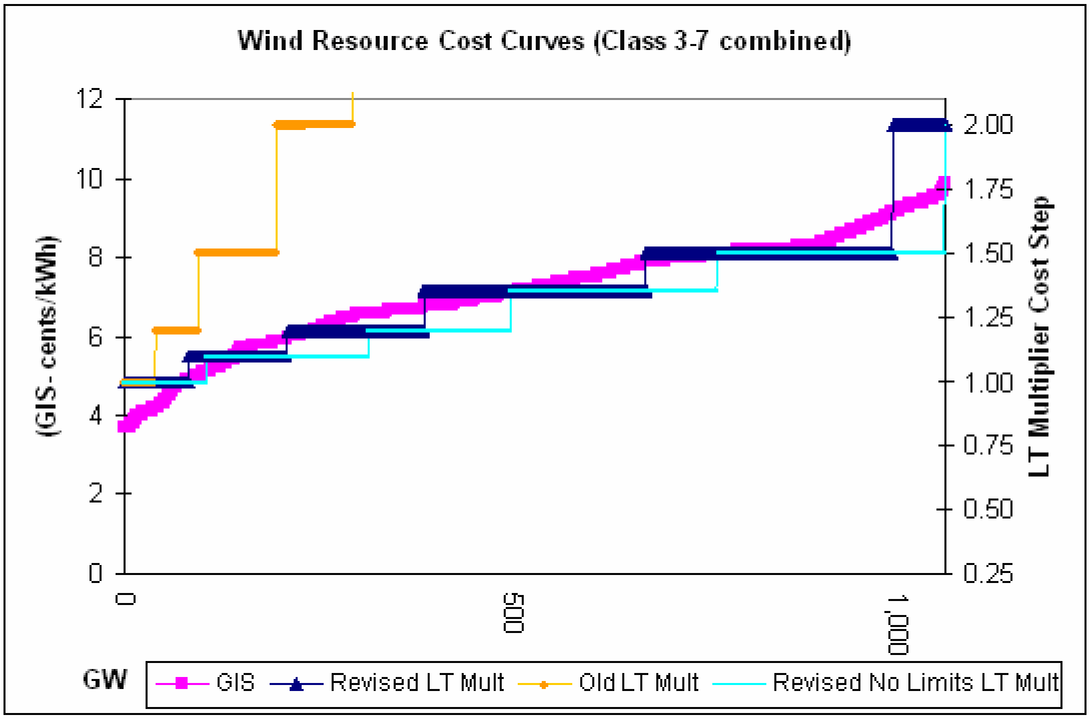
Second, we believe Congress will likely adopt a more stable long-term policy for wind and other renewable energy technologies, such as a national RPS and/or a long-term extension of the PTC, in the near future. This would provide increased stability and certainty that will facilitate manufacturers to build new plants and add capacity at existing facilities.

Third, the wind industry is relatively small compared to the fossil fuel industry and has significant room for expansion. The rapid ramp-up in manufacturing of gas turbines from 3.5 GW in 1999 to 63 GW in 2002 shows that it may be possible to ramp-up wind turbine manufacturing fairly quickly, particularly since wind turbines are a modular technology like gas turbines.

We also increase the capital costs of wind at the regional level as the penetration of wind increases to account for additional transmission costs, resource degradation, and siting costs. We do this by modifying EIA's long-term capital cost multipliers for wind based on a detailed analysis performed by NREL using their GIS and WinDS models that accounts for increases in slope and population density. NREL developed supply curves of the windy land area available in each wind resource class (3-7) for thirteen electricity reliability regions. These supply curves are then divided into steps to correspond with the multiplier levels assumed by EIA. One main difference is that EIA only includes class 4-6 wind resources, while our analysis also includes class 3 wind resources.

Previous analyses by UCS and EIA have shown that the NEMS model rarely uses the fairly large portion of the wind supply curve that EIA assumes will fall into the last two multiplier levels, which increase capital costs by 200 and 300 percent. Thus, we effectively exclude these resources in the model and develop additional multiplier steps at the lower end of the supply curve by breaking out the resource into multiplier steps of 1.0, 1.10, 1.20, 1.35, and 1.50 (vs. EIA's 1.0, 1.2, 1.5, 2.0, and 3.0). These changes are illustrated at the national level in the figures below.





Financing
For both the UCS and EIA case, we use EIA's financing assumptions from AEO 2007, which equate to a fixed charge rate of 11.3 percent and includes 5-yr accelerated depreciation and interest during construction. For the UCS case, we also assume a construction lead-time of one year vs. EIA's assumption of three years, based on Black & Veatch's assumption that projects will only be paying interest during a period of up to one year when they are under construction.

Capacity Factors
For the UCS case, we use B&V's projections, which are based on a curve fit to historical projections and new turbine designs. EIA's more pessimistic estimates assume only slight improvement in performance over time. As stated above, we are including class 3-7 wind resources in the model based on NREL's analysis whereas EIA only includes class 4-7. For both cases, the class 7 potential is included in the estimate for class 6.

O&M costs
For the UCS case, we use B&V's O&M cost projections, which assumes fixed O&M costs will not change over time, while variable O&M costs will decline over time based on historical trends.

Table 9. Onshore Wind Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	1,260 (2005) 1,480 (2006) 1,600 (2007-2010) 1,440 (2030)	1,440 (2009-2030)
Real Escalation	Included above; 17.5% increase 2005-2006, 33% from 2005-2007.	Not included
Learning capital costs	Linear 10% reduction by 2030	No learning. Assumes wind is a mature technology.
Capacity factor	--Class 3 = 33% in 2007 increasing to 38.4% in 2030. --Class 6 = 44.5% in 2007 increasing to 48.7% in 2030.	Class 4-6 = 30%-42%. Almost no increase over time.
O&M (2006$)	--Fixed O&M = $11.2/kW fixed over time. --Variable O&M = $6.8/MWh in 2005 declining to $4.2/MWh by 2030	--Fixed O&M = $28.5/kW-yr fixed over time Variable O&M = 0

References
Wiser, R. and M. Bolinger, 2007a. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*, prepared by Lawrence Berkeley National Laboratory for the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, May.

Wiser, R., 2007b. "Wind Power and the Production Tax Credit: An Overview of Recent Research," Testimony Prepared for a Hearing on Clean Energy: From the Margins to the Mainstream, U.S. Senate Finance Committee, March 29.

Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

Wind Offshore

EIA does not include offshore wind in their model. We added it based on work completed by OnLocation Inc. for DOE's Office of Energy Efficiency and Renewable Energy. Cost and performance projections are based on B&V projections for Wind Vision study for shallow and deep water.

Table 10. Shallow Offshore Wind Assumptions

	UCS Case
Overnight capital cost (2005$/kW)	2,230 (2010) 2,050 (2030)
Real Escalation	Included above
Learning capital costs	Linear 10% reduction by 2030
Financing	EIA/AEO 2007 assumptions for onshore wind
Capacity factor	--Class 3 = 36.6% in 2010 increasing to 40.3% in 2030. --Class 6 = 48.2% in 2010 increasing to 51% in 2030.
O&M (2005$)	Fixed O&M = $14.6/kW-yr fixed over time Variable O&M = $20.4/MWh in 2005 declining to $10.4/MWh in 2030.

References
Ric O'Connell, Black & Veatch, Cost and performance inputs for the DOE Wind Collaborative 20 percent Wind Vision analysis, May 2007 (updated). The full report is scheduled to be released in November 2007.

Biomass IGCC
There is considerable uncertainty around the cost and performance of biomass IGCC, as very little data exists from actual projects. For the UCS case, we assumed B&V's cost for coal IGCC plus the difference between EIA's coal and biomass IGCC costs. We also assume higher heat rates than EIA based on B&V's heat rate for coal IGCC plus the difference between EIA's coal and biomass IGCC heat rates. The rest of the assumptions are the same as EIA's assumptions for biomass IGCC.

Biomass Fuel Supply. EIA's biomass supply schedule has four components: agricultural residues, urban wood waste and mill residues, forestry residues, and energy crops. For our analysis we maintained the same curve for agricultural residues that was used for the AEO 2007 analysis. For the urban wood waste and mill residues we applied an additional exclusion of 2.5% beyond EIA's supply to provide an extra margin against using contaminated materials. We also reduced the amount of forestry residue available by an additional 50 percent from EIA's supply estimates in order to avoid including any forest residues that might have been supplied through unsustainable practices.

For the energy crop supply, we started with the original switchgrass data in EIA's supply curve that was generated by the University of Tennessee's POLYSYS model. We used the production quantities for each POLYSYS region to generate weighted average yields (dry tons per acre) for each of the Coal Demand regions in NEMS. We then decreased the yields by 0.5 dry tons to account for changes in harvesting technology adjusted the energy crop supply curve for the initial 2010 estimates in NEMS. We then increased yields at a consistent annual percentage rate by region through 2030 based on more recent estimates used in the POLYSIS model.[4]

Table 11. Biomass IGCC Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	3,390 (2010) 3,104 (2030)	1,852 (2010) 1,566 (2030)
Real Escalation	Included through 2010 (same as coal IGCC	None
Learning	Half of EIA's learning rates (same as coal IGCC)	17% cost reduction by 2030 in AEO 2007 reference case
Capacity factor	80% (same as coal IGCC)	83%
Fixed O&M (2005$/kW-yr)	EIA	50.2
Variable O&M (2005 mills/kWh)	EIA	3.2
Fuel	EIA supply curve, with 50% exclusion to forest residues, 2.5% exclusion to	Depends on demand for biomass at regional level. Prices

[4] Walsh, Marie. Personal communication . June 12 and June 18, 2007.

	urban/mill residues, and an increase in energy crop yields between 2010 and 2030.	increase as demand increases.
Heat Rate (Btu/kWh)	9,985 in 2010 declining to 9,519 in 2030	8,911 (stays fixed over time)

Biomass Co-firing
NEMS also allows for biomass co-firing with coal in existing coal plants. For the purposes of this analysis we used EIA assumptions from AEO 2007 for both the UCS case and the EIA case.[5]

Geothermal
EIA's assumptions for the cost, performance, and resource potential for geothermal power plants are included in the Geothermal-Electric Power Submodule of NEMS. The submodule contains a supply curve for geothermal resources that reflects estimates of the capacity, generation, and costs of producing electricity at 89 hydrothermal sites in the Western U.S. EIA also assumes that geothermal power plants will operate at a 90 percent capacity factor and they include an annual build limit of 25 MW per site until 2010 and 50 MW per site through 2030.

The data included in EIA's geothermal supply curve is based on a 2004 study by GeothermEx, Inc. for the California Energy Commission (Lovekin, 2004) and a 2006 study by the Western Governor's Association Geothermal Task Force for the Clean and Diversified Energy Initiative. These studies focused on geothermal conventional hydrothermal sites with confirmed temperatures greater than 100 degrees Celsius. The WGA study found that 5,600 MW of new hydrothermal capacity could be developed in the western US by 2015 for less than 8 cents/kWh with the production tax credit or less than $103/MWh without the PTC, and up to 13,000 MW by 2025 for less than $200 /MWh.[6] Other potential geothermal resources, such as geothermal fluids co-produced with oil and gas, and Enhanced Geothermal Systems (EGS), including hot dry rock, were not included in these studies. EIA decided not to include these potential resources in the supply curve because they did not believe they would be in significant commercial use within the forecast horizon of 2030. All told, the EIA supply curve includes roughly 9,000 MW of hydrothermal capacity.

At least two new updated geothermal resource assessments have been completed since the Lovekin (2004) and WGA (2006) studies that address these non-conventional resources. These include a comprehensive study completed in 2006 by MIT (Tester, 2006) that included an assessment of the U.S. potential for EGS through 2050 and a January 2007 paper by Black Mountain Technology and NREL (Petty and Porro, 2007) that includes the EGS estimates from

[5] For more information on the assumptions for biomass co-firing, see EIA's NEMS Model Documentation for the Renewable Fuels Module, available online at www.eia.doe.gov.
[6] This represents a 15-yr levelized busbar cost in 2005 dollars.

the MIT study along with updated supply estimates for hydrothermal and convective EGS resources based on eight different studies (including Lovekin and WGA).

The Petty and Porro study found a total national geothermal resource potential of 126,000 MW mostly below a levelized cost of $200/MWh (2004$), including 89,000 MW across all resource types in the Western US and 37,000 MW of potential almost entirely from co-produced sites in the Southeast and Southern Plains states. This data was put into a format suitable for use in the NEMS and broken down into five specific resource types:

- hydrothermal flash
- hydrothermal binary
- geothermal fluids co-produced with oil and gas
- convective EGS associated with hydrothermal resources at depths less than 3 kilometers
- conductive EGS for depths between 3 and 10 kilometers.

In addition to addressing the co-produced and EGS resources not included in the EIA supply, the study also more broadly assessed hydrothermal resources, generally consistent with techniques adopted in earlier USGS geothermal resource assessments. This broader assessment resulted in 27 GW of total hydrothermal potential at generally lower cost than the EIA supply analysis.

We used the supply data from this assessment with a few adjustments. First, we worked with Petty to incorporate recent increases in capital costs for geothermal to make the costs consistent with the assumptions for other technologies. This was done by applying specific price indices for drilling, turbines, heat exchangers, construction materials, labor, and steel to modify costs from 3rd quarter 2004 values to end of the year 2006 values. We also removed the effects of inflation. We then projected these indices to incorporate additional real escalation through 2010 based on a historical trend curve fit. Second, we assumed co-produced sites would not be available for commercial development until after 2030 due primarily to consideration of market factors other than cost. This exclusion of the co-produced resources effectively limits supply to the Western US.

While geothermal supply information is the key input to the Geothermal-Electric Power Submodule, two additional assumptions were made that also significantly contribute to the amount of geothermal supply absorbed by the electricity market in each year of the forecast. First, learning rates, in the form exogenous multipliers to capital and O&M costs, are conservative and assume no impact from DOE R&D. Second, annual build limits allow a maximum of 100 MW to be developed each year at each site. This limit, twice that assumed by EIA, accounts for the larger capacities associated with each site in the Petty and Porro supply characterization (resulting from regional aggregation). A revised version of the supply curve for the year 2010 is shown in the figure below.

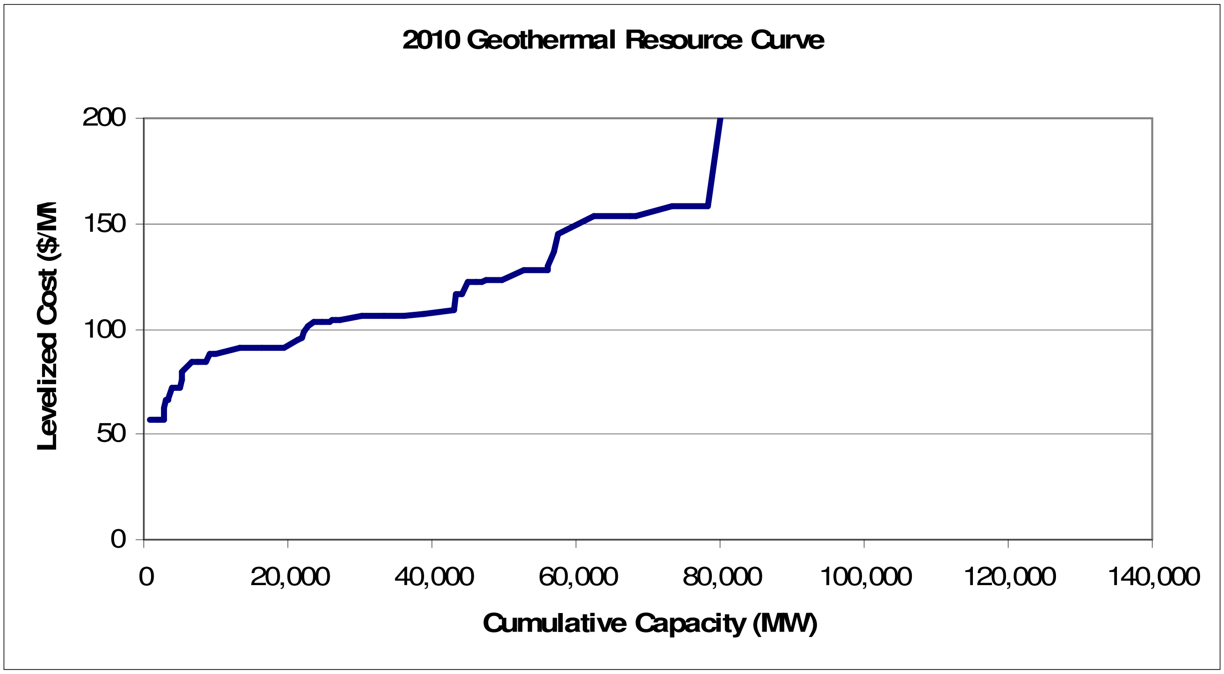


Table 12. Geothermal Assumptions

	Mid	EIA
Overnight capital cost (2005$/kW)	Varies by site and technology Hydrothermal resource: ~2,700-5,400 (2006) ~3,000-6,150 (2010)	Varies by site and technology
Real Escalation	7.5%/yr increase in exploration and drilling costs 3.3%/yr average increase in power plant and field costs (2005-2010)	
Learning	Exogenous multipliers to capital and O&M costs assume no impact from DOE R&D	8% capital cost reduction for every doubling in installed capacity for 5 doublings
Financing	EIA	EIA
Capacity factor	90-95%	90%
O&M (2005$/kW-	Varies by site and technology	

yr)	Hydrothermal resource: ~73-142 (2006) ~76-146 (2010)	
Annual site build limit	25 MW per year through 2007 increasing to 100 MW per year through 2030	25 MW per year through 2010 50 MW per year through 2030

The Geothermal Energy Association completed a survey in May of 2007 that identifies up to 2,456 MW of new geothermal power plant capacity is currently under development in the United States (including projects in the initial development phase). Up to 371 MW of capacity is currently under construction at 12 projects in 5 states. Unconfirmed projects (some of which are likely to be developed within the next few years) raise these numbers to 2,856 MW of potential capacity currently under consideration. There are 12 states with projects currently under consideration or development, including: Alaska, Arizona, California, Hawaii, Idaho, Nevada, New Mexico, Oregon, Texas, Utah, Washington and Wyoming.

Table 13. New Geothermal Projects under Development in the US

State	**Not Confirmed**	**PHASE 1 (Identifying site, secured rights to resource, initial exploration drilling)**	**PHASE 2 (Exploratory drilling and confirmation)**	**PHASE 3 (Securing PPA and final permits)**	**PHASE 4 (Production Drilling and Under Construction)**
AK	1/15 MW	2/45 MW			1/0.6 MW
AZ		1/2-20 MW			
CA		4/280-290 MW	3/326.8 MW	7/279.5 MW	2/35-73 MW
HI		1/30 MW		1/8 MW	
ID	2/200 MW		1/26		1/13 MW
NM			2/21 MW		
NV		8/288-372 MW	11/167-300 MW	5/217-227 MW	7-273 MW
OR		3/3 MW		4/125.2- 210.2 MW	
TX		1 – Lease sale			
UT	2/135 MW		1/36.6 MW		1/11 MW
WA		1- undefined			
WY			1/0.2MW		
Total	**5 projects 350 MW**	**21 projects 648-760 MW**	**19 projects 577.6-710.6 MW**	**17 projects 584.7-724.7 MW**	**12 projects 332.6-370.6 MW**

Source: GEA, May 2007

References
Petty, S., and G. Porro, 2007. "Updated Geothermal Supply Characterization," Proceedings, Thirty-Second Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 23-24.

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Lovekin, J., Klein, C., and S. Sanyal, 2004. *New Geothermal Site Identification and Qualification*, prepared by GeothermEx, for the California Energy Commission's Public Interest Energy Research (PIER) program, Consultant Report #P500-04-051, June.

Tester, J.W., 2007. "The Future of Geothermal Energy," Testimony for a hearing on Developing Untapped Potential: Geothermal and Ocean Power Technologies, U.S. Senate Subcommitee on Energy and Environment, May 17.

Tester, J.W., Petty, S., Garnish, J., Batchelor, A., Drake, L., and R. Veatch, 2006. "The Future of Geothermal Energy – Energy Recovery from Enhanced/Engineered Geothermal Systems (EGS) – Assessment of Impact for the U.S. by 2050," Massachusetts Institute of Technology report, Cambridge, MA, Final Report to the U.S. Department of Energy Geothermal Program.

Personal communications with Jeff Tester, Gian Porro, Martin Vorum, Gerry Nix, and Susan Petty, June 2007.

Mansure, A.J., Bauer, S.J., Lindsay B.J., and S. Petty, 2006. "Geothermal Well Cost Analyses 2005 and 2006," Sandia National Laboratories.

Geothermal Energy Association, 2007. "Update on US Geothermal Power Production and Development," May 10.

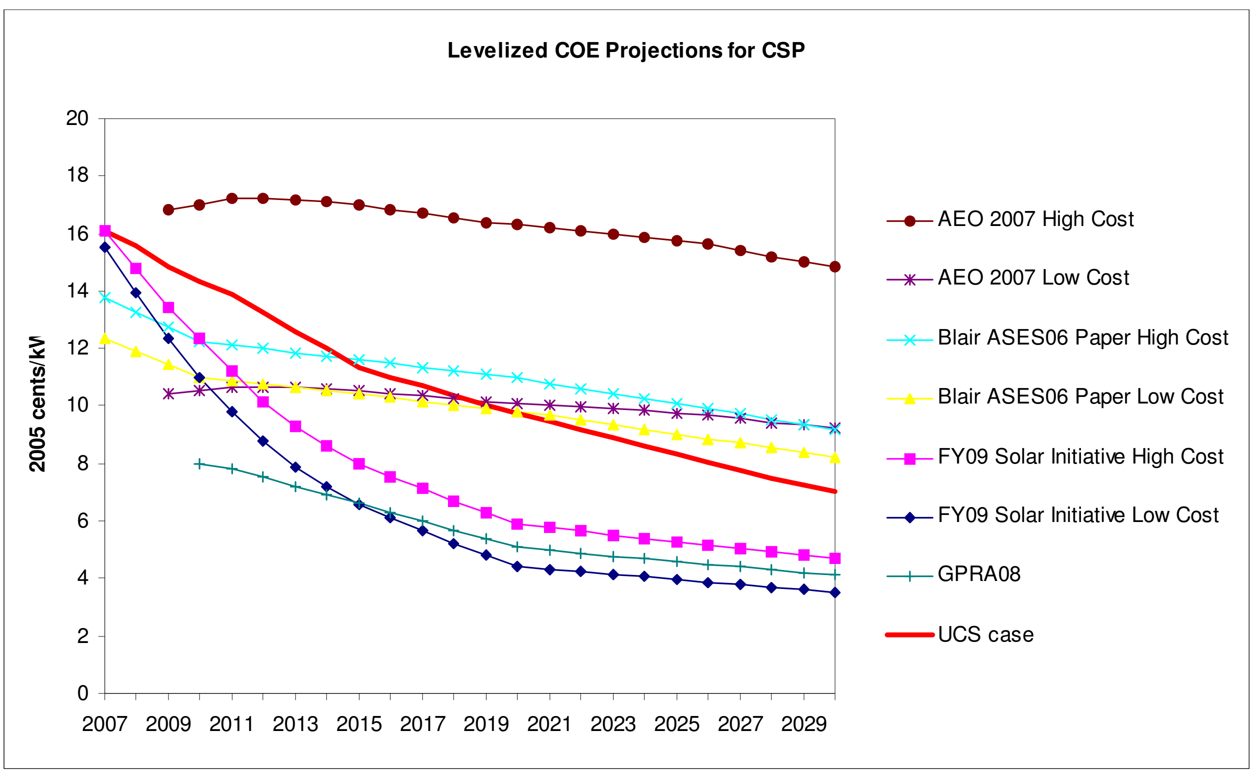
Concentrating Solar Thermal

Limited data is available on actual projects. We were only able to obtain data on levelized costs for one recent project—a 64 MW project in Nevada with an in-service date of May 2007—that has a reported power purchase agreement (PPA) price of 16 cents/kWh.

We reviewed several recent studies to develop our assumptions for the UCS case. We used projections from the FY09 Solar Initiative, which have initial levelized costs that appear to be consistent with the levelized costs from the Nevada project. However, we make a few important adjustments to the assumptions from this study. First, we assume less improvement in capacity factors over time with increasing levels of thermal storage. We assume capacity factors will increase from 43 percent in 2010 (assumes six hours of storage), to 49 percent in 2010, and 55 percent by 2030 compared to 72 percent in 2015 and 82 percent in 2030 in the FY09 Solar Initiative. We also assume a linear reduction in capital and O&M costs between 2010 and 2030 to account for potential cost savings from having less storage. The resulting total levelized costs from using these assumptions fall in the middle of the range of the FY09 Solar Initiative, EIA's low cost case and a recent study by NREL.

Table 14. Concentrating Solar Thermal Assumptions

	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	5,500 (2005) 4,380 (2010) 2,560 (2030)	3,146 (2005) 2,796 (2010) 2,286 (2030)
Real Escalation	Included in higher initial estimates from FY09 Solar Initiative	None
Learning	53% capital cost reduction by 2030	24% capital cost reduction by 2030
Capacity factor	45% (2010) 49% (2015) 55% (2030)	24.6%-39.7%, varies by region, fixed over time
Fixed O&M (2005$/kW-yr)	74 (2005) 50 (2010) 28 (2030)	53.4 fixed over time



References

U.S. DOE, *Concentrating Solar Power: FY09 Proposed Solar Initiative*, Budget Summit Meeting at the National Press Club, March 15, 2007.

U.S. DOE, Government Performance Review Act FY08, *Appendix D: Solar Energy Technologies Program Inputs for FY08 Benefits Estimates*.

Nate Blair, Walter Short, Mark Mehos, and Donna Heimiller, National Renewable Energy Laboratory, "Concentrating Solar Deployment System (CSDS) – A New Model for Estimating U.S. Concentrating Solar Power Market Potential," paper prepared for the American Solar Energy Society 2006 conference.

Central Station PV

Data on actual central station photovoltaic projects is also extremely limited. To account for the recent escalation in construction and materials costs affecting all technologies, we used capital cost estimates from DOE's FY08 Government Performance Review Act (GPRA08) analysis through 2010. Initial costs from GPRA08 were 26 percent higher than EIA's initial estimates for central PV plants installed in 2008. After 2010, we assume the mid-range of capital costs projected in GPRA08 and EIA's assumptions for AEO 2007.

Table 15. Central Station PV Assumptions

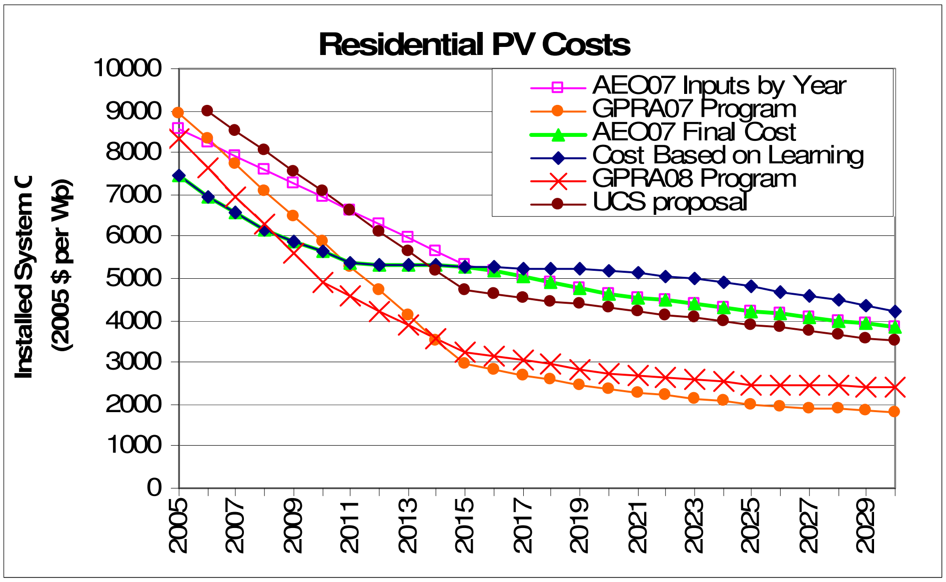
	UCS Case	EIA Case
Overnight capital cost (2005$/kW)	5,355 (2006) 2,487 (2030)	4,248 (2008) 2,985 (2030)
Real Escalation	Assumed to be included in higher initial costs	None
Learning	54% reduction by 2030	36% reduction by 2030
Capacity factor	EIA	20.4% fixed over time
Fixed O&M (2005$/kW-yr)	24 (2006) 10 (2030)	11 fixed over time

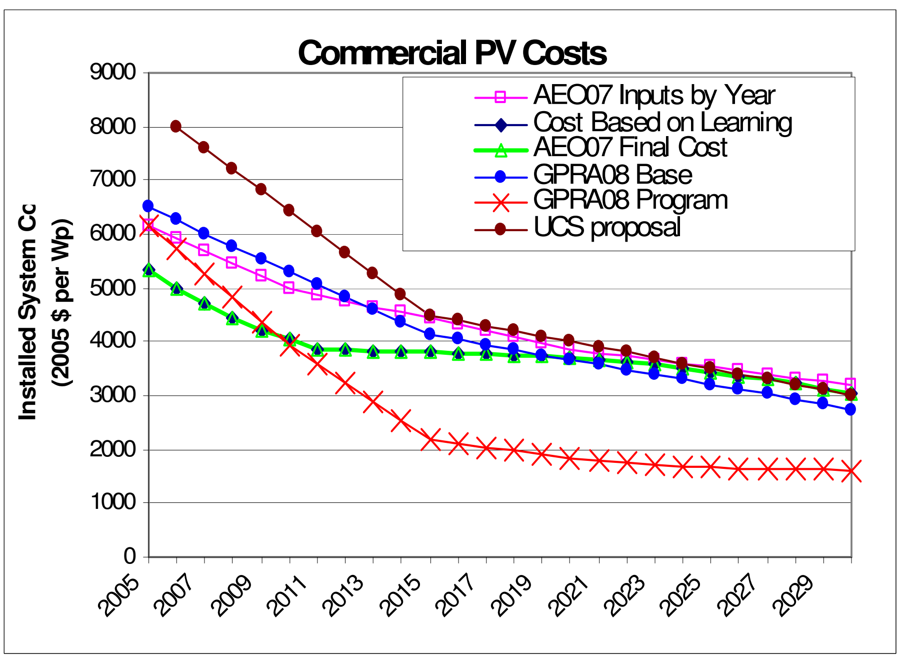
References

U.S. DOE, Government Performance Review Act FY08, *Appendix D: Solar Energy Technologies Program Inputs for FY08 Benefits Estimates*.

Distributed PV

For the UCS case, we use data from thousands of actual residential and commercial PV projects that have been installed as a result of California's solar program. This data shows an average installed cost of $9,000 per watt (2005$) for residential scale systems under 5 kW and $8,000 per watt for commercial scale systems of 50-100 kW installed in 2006. We use this data as the starting point and assume total installed costs will fall over time at the levels similar to those projected EIA and the DOE Solar program for the DOE FY08 Government Performance Review Act. This results in the equivalent of a 5 percent annual cost reduction between 2005 and 2015, and a 1 percent annual cost reduction between 2015 and 2030. For comparison, a recent study by LBL (Wiser, 2006) showed an annual average reduction of approximately 7 percent between 1998 and 2005 for California solar PV program (see Figure below).





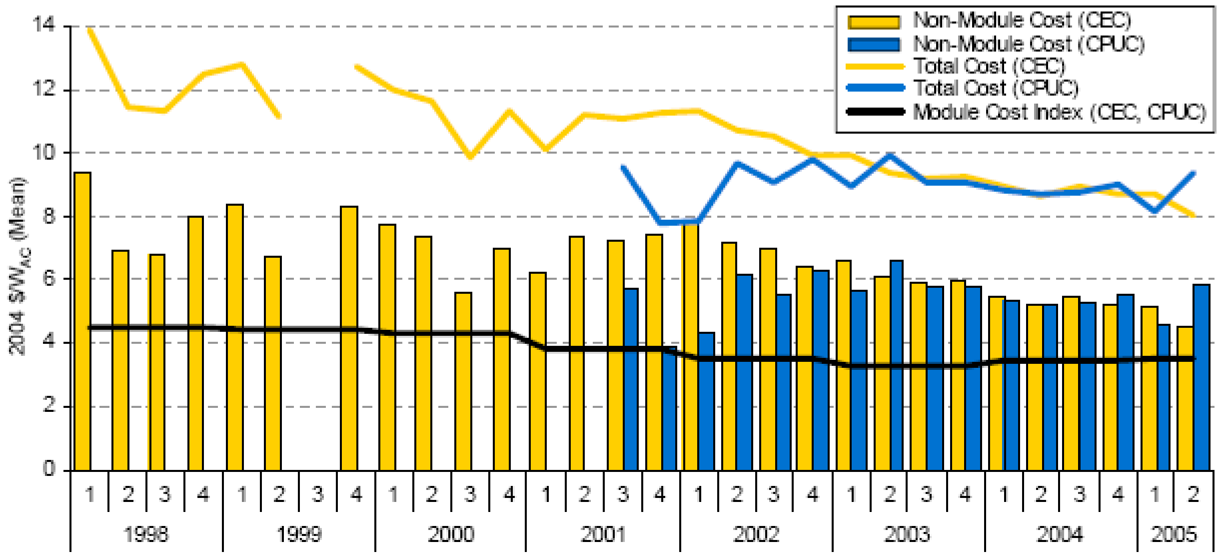


Figure ES-2. Costs Trends Over Time (CEC and CPUC)

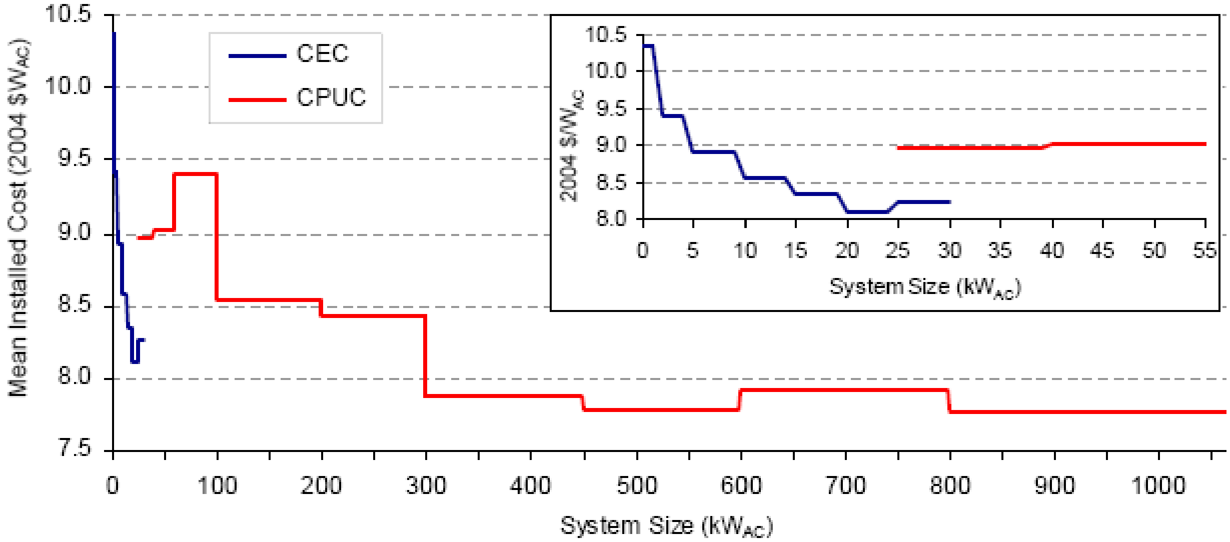


Figure ES-4. Installed Cost, by System Size (CEC and CPUC)

References
Ryan Wiser, Mark Bolinger, Peter Cappers, and Robert Margolis, *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*, Lawrence Berkeley National Laboratory, January 2006, online at http://eetd.lbl.gov/EA/EMP.

Modeling the Impacts of State RPS Policies

As part of the AEO 2007, EIA developed a module in NEMS to model the long-term effects of state RPSs at the regional level. For the AEO 2007 reference case, however, EIA did not include additional renewable energy projects that would be needed to fully comply with the annual requirements under some state standards. Instead, EIA assumed that several states underachieve their annual requirements due to lack of enforcement, granting of compliance waivers by regulatory agencies, and the use of alternative compliance payment mechanisms.

A regional RPS side case was included in AEO 2007, which assumed "nondiscretionary" compliance with the state RPS policies in place as of September 2006. When compared with EIA's regional RPS case, EIA's reference case will achieve less than half of the annual state requirements for new renewable energy generation. Total non-hydro renewable energy generation reaches 4.1 percent and 5.1 percent of total U.S. electricity sales by 2020 respectively, for the EIA's reference case and regional RPS side case.

For our analysis, we modeled two reference cases: 1) a case that assumed states with renewable electricity standards fully achieve their annual targets, and 2) a case that assumed partial compliance with state renewable standards. We used EIA's regional RPS model to project the generation needed to meet the state standards, and include this in both the reference and policy cases. In addition, we updated the regional targets to include increases in several state standards (Arizona, Colorado, Connecticut, Delaware, New Mexico, Maine, Maryland, and Minnesota) and the adoption of five new standards (Illinois, New Hampshire, North Carolina, Oregon, Washington) that occurred from September 2006 through August 2007. EIA's regional RPS model is not capable of examining separate solar or distributed generation set-aside requirements that are included in nearly half of the state standards. To account for this market, UCS projected the solar energy generation needed to achieve these separate requirements, and built that development into the commercial and residential end-use sectors.

These changes resulted in total renewable generation reaching 6.6 percent of total U.S. electricity sales in 2020 under the reference case assuming states achieve full compliance and 5 percent under the scenario assuming partial compliance.