Program on Technology Innovation: Integrated Generation Technology Options

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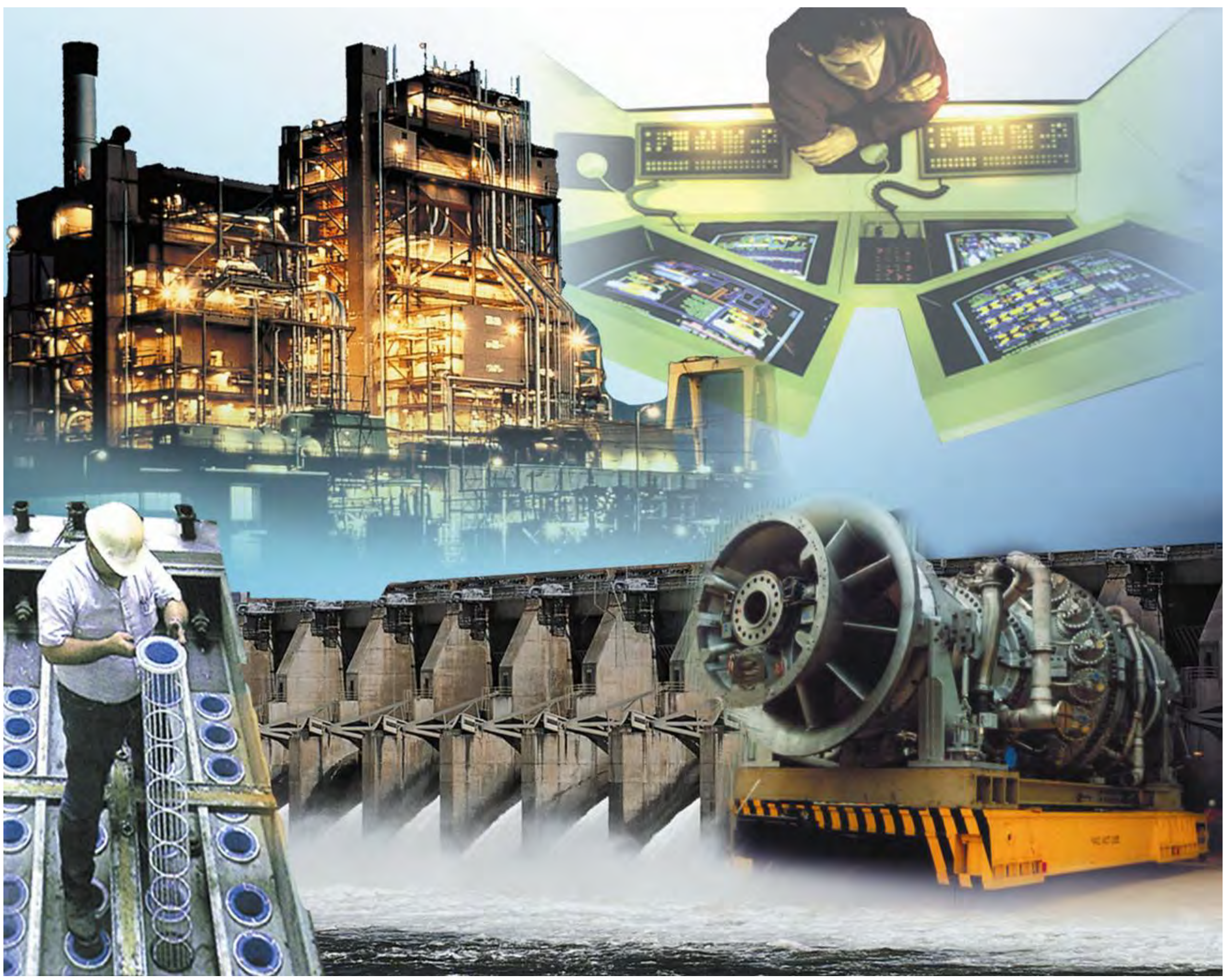

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Technical Update, June 2011

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THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

Electric Power Research Institute (EPRI)

This is an EPRI Energy Technology Assessment Program report based on 2010 research under EPRI's Technical Assessment Guide (TAG®), Renewable Generation, and CoalFleet for Tomorrow Programs. This report will be updated periodically to be consistent with future research.

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

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PRODUCT DESCRIPTION

This report provides a condensed, public-domain reference for current cost, performance, and technology status data for eight central-station power generation technologies. In this report, central station is defined as >100 MW with the exception of some renewable-resource-based technologies. In addition to fossil- and nuclear-based technologies, four renewable-resource-based technologies are included. This report addresses the principal technology options for utility-scale power generation.

Results and Findings

Planning for new U.S. power generation is in a state of flux due to uncertainty associated with recovery of recession-driven declines in electricity consumption, the impacts of anticipated regulations on existing generation, and potential future climate policy. U. S. electricity consumption began to recover in 2010 after back-to-back declines in 2008 and 2009 due to the economic crisis. However, the electric sector continues to feel the impacts of the recession from high unemployment rates, slow recovery of the industrial sector, and tighter credit markets. Anticipated environmental regulations may have significant impacts on existing generation including substantial capital investment in environmental controls retrofits and retirement of older, less-efficient generating stations. Longer-term implications of potential future U.S. climate legislation continue to be a factor in integrated resource planning.

Challenges and Objectives

This report focuses on eight key central-station technologies that are of interest to the industry and are likely to dominate the U.S. generation mix over the next two decades. While forecasting future costs is challenging, estimates of future costs and performance can be made based on technology development trends.

Applications, Value, and Use

With a continued public focus on environmental issues and the electric sector, the scope and breadth of analyses by the Electric Power Research Institute (EPRI) and others, addressing impacts of policy and economic trends on technology development, have continued to grow. These analyses rely on assumptions about generation technology cost and performance. This report provides a basis for EPRI energy-economic analyses as well as a reference for stakeholders who need credible data on performance and cost of conventional and emerging electricity technologies. This report is based on more detailed research results presented in the 2010 EPRI report Technical Assessment Guide (TAG) – Power Generation and Storage Technology Options (1019822) and the 2010 EPRI report Renewable Energy Technology Guide (1019760).

EPRI continues to make this report publicly available to meet the demand for credible technical information created by the continued growth in planning for power generation and analysis of the electricity sector. Its publication responds to requests from a range of stakeholders to disseminate power generation technology information more widely.

Approach

This report presents essential cost and performance data on eight utility-scale power generation technologies drawn from ongoing research under the EPRI Technical Assessment Guide, Renewable Generation, and CoalFleet for Tomorrow Programs. Levelized costs of electricity are calculated based on methods generally consistent with those used in the EPRI Technical Assessment Guide.

Keywords

Central station power generation technologies
Cost and performance
Levelized cost of electricity
Technology evaluation
Technology trends

LIST OF ABBREVIATIONS

AFUDC: Allowance for Funds Used During Construction
AGR: Advanced Gas-cooled Reactor
ALWR: Advanced Light Water Reactor
ARRA: American Reinvestment and Recovery Act
BWR: Boiling Water Reactor
CC: Carbon Capture
CCS: Carbon Capture and Storage
CF: Capacity Factor
CFB: Circulating Fluidized Bed
CLFR: Compact Linear Fresnel Reflector
COE: Cost of Electricity
COL: Combined Operating License
COLA: Combined Operating License Application
CST: Concentrating Solar Thermal
CT: Combustion Turbine
CTCC: Combustion Turbine Combined Cycle
DC: Direct Current
DOE: Department of Energy
EPA: Environmental Protection Agency
EU: European Union
FBC: Fluidized Bed Combustion
FGD: Flue Gas Desulfurization
FOM: Fixed Operating and Maintenance Costs
GHG: Greenhouse Gas
GW: Gigawatts
HHV: Higher Heating Value
HRSG: Heat Recovery Steam Generator
HTF: Heat Transfer Fluid
IB MACT: Industrial Boiler Maximum Achievable Control Technology
IGCC: Integrated Gasification Combined Cycle
IPP: Independent Power Producer
LCOE: Levelized Cost of Electricity
LFR: Linear Fresnel Reflector
LWR: Light Water Reactor

MACRS: Modified Accelerated Capital Recovery System
MMBtu: one million British thermal units.
MW: Megawatts
NRC: Nuclear Regulatory Commission
NREL: National Renewable Energy Laboratory
O&M: Operation and Maintenance
OEM: Original Equipment Manufacturer
PC: Pulverized Coal
PPA: Power Purchase Agreement
PRB: Powder River Basin (coal)
PV: Photovoltaic
PWR: Pressurized Water Reactor
RES: Renewable Energy Standard
RETG: Renewable Energy Technology Guide
RPS: Renewable Portfolio Standards
SCR: Selective Catalytic Reduction
SMR: Small Modular Reactor
SCPC: Supercritical Pulverized Coal
TAG: Technical Assessment Guide
TCR: Total Capital Required
TPC: Total Plant Cost
USC PC: Ultra-Supercritical Pulverized Coal
VOM: Variable Operating and Maintenance Costs

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1
INTRODUCTION

1.1 Overview

The *Integrated Generation Technology Options* report provides an executive-level overview of near-term (5 – 10 years) as well as longer term (2025) electricity generation technology costs and performance. The purpose of this document is to provide a public domain reference for industry executives, policy makers, and other stakeholders. This report is based on 2010 EPRI research results and updates the *Integrated Generation Technology Options* report published in November 2009. [1]

Produced by EPRI's Energy Technology Assessment Center (ETAC), this report draws on the 2010 *Technical Assessment Guide* (TAG®) [2] and the 2010 *Renewable Energy Technology Guide* (RETG) [3] to provide an overview of cost and performance estimates of power generation technologies in the following categories:

- Central stations, including advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), natural gas combustion turbine/combined cycle (NGCC or CTCC) and nuclear generation. Fossil technologies are presented both without and with carbon capture technologies for 2025.
- Renewable resources, including wind, biomass, solar thermal, and solar photovoltaic technologies.

For each technology area, the report presents an overview of each technology, including:

- A brief description of the technology
- Current and projected technology performance and costs
- Major technical issues and future development direction/trends
- Fuel resource considerations
- Relevant business issues
- Environmental concerns and considerations

The scope of this report includes capital costs, operations and maintenance (O&M) costs, performance data, and technology trends. For comparison purposes, costs are reported in constant December 2010 dollars.

Cost and performance estimates are idealized for representative generating units based on detailed EPRI research results. Estimates are not intended to apply to specific energy companies, sites, or projects since site-specific and company-specific conditions can lead to substantially different costs and performance.

1.2 Trends

Uncertainty in planning for new power generation technologies is currently affected by several key factors: 1) the recession and its impacts on electricity demand, 2) capital cost uncertainties surrounding the various technologies, 3) uncertainty regarding potential carbon legislation, 4) the profound impact of the shale gas boom on present and future natural gas prices, and 5) impacts on existing generating plants from pending or anticipated environmental rules on emissions, use of water resources, and coal ash handling and disposal.

Coal-based new power generation capacity additions have slowed due to uncertainty surrounding potential future carbon legislation, technical and economic feasibility of carbon dioxide (CO_2) emissions capture and storage, new emissions controls regulations, and increasing capital costs. Planning for new nuclear generation continues, but faces challenges in financing stemming from high capital costs, long lead times in licensing and construction, and rising cost projections. Natural gas combined cycle generation appears to be poised for significant growth over the next decade as aging coal units are retired and confidence in shale gas resource estimates and lower gas price projections increases.

New capacity addition in the renewable sector also faces challenges due to the economic downturn and the difficulty arranging for financing, as well as the uncertainty regarding passage of a federal renewable energy standard. Despite a slowdown in 2010, onshore wind generation growth continues at a significant pace and is beginning to play a more important role in the electricity supply in some regions. Solar thermal and photovoltaic (PV) technology have experienced increased activity, but the magnitude of total capacity additions are still quite limited, making up less than 1% of U.S. electric sector generation. Biomass technology deployment has slowed due to in part to concerns with pending regulation on industrial boiler environmental control technology. Although renewable technologies are a growing fraction of the generation technology mix largely due to government incentives and regulatory requirements, the issue of their integration on a much larger scale in the utility system is only beginning to be addressed.

In general, the data in this report reflect cost increases over the last five years due to heightened worldwide construction activity as well as a resumption of commodity price escalations following the worldwide recession. Pulverized coal plant estimates have declined slightly consistent with the broader slowdown in industrial construction. IGCC and nuclear generation construction cost estimates continue to increase as the first commercial-scale IGCC projects move forward and U.S. nuclear project licensing reviews continue. Onshore wind farm construction costs have stabilized, reflecting the maturity of this technology. Solar photovoltaic and solar thermal capital cost estimates continue to decline based on improvements in the technology and the growing solar technology marketplace and supply chain.

1.3 Differences between Generic and Project-Specific Estimates

While the information in this document is generic and is not tailored to site-specific studies, it provides baseline information with appropriate qualitative references to site-specific conditions that may have an impact on the estimate.

TAG® and RETG contain data that is timely, applicable to competitive markets, and of regulatory quality. In this context, the design basis, the cost estimate basis, and the economic basis are linked together to the cost of electricity and the level of detail for each need to be defined. For technology screening level studies, TAG® and RETG cost estimates are conceptual estimates that differ from site-specific project estimates for a number of reasons, including:

- Project estimates are more detailed and often based on current dollars (with escalation and inflation) with reference to future commercial service date.
- Individual companies' design bases vary (for example, the amount of equipment redundancy included for reliability).
- Owner costs as well as site-specific costs in project estimates are frequently higher.
- Interest during construction for specific projects is frequently greater.
- Site-specific requirements, such as fuel delivery, transition, tie-in, and raw water requirements, also have an impact on the costs.
- Transmission system improvements required to support large capacity additions or remote generation can often be significant.

1.4 Cost Estimation Uncertainty

As the power generation technologies are quite capital intensive, there are several technical, economic and financial factors that influence the variations in capital cost from one technology to another and from one project to another. Higher uncertainty with respect to performance of a key component in a new technology will result in more significant impact on the cost estimate. Many factors contribute to the overall uncertainty of an estimate. They can generally be divided into four generic types:

1. Technical —Uncertainty in physical processes, performance estimates based on limited data, or scaling uncertainty.
2. Estimation—Uncertainty resulting from estimates based on preliminary designs, and uncertainty in project execution. Power generation technologies require large amounts of concrete, structural steel, equipment operating under high pressure/temperature, and several thousands of hours of manpower to engineer and construct these facilities. The planning and execution of the activities takes several years, and the capital expenditure for these plants is spread over several years. The project schedule – including construction schedule – to bring the technologies on line depends on factors such as the lead time to obtain the necessary permits, lead time for equipment and material procurement and possible delays, and construction time. The total project schedule can be on the order of two to three years for combustion turbines and wind turbines, six to eight years for coal based technologies and up to ten years for a nuclear power plant. These ranges contribute to the significant differences in estimates based on constant dollar versus current dollar analysis (see discussion in section 1.5.3).
3. Economic—Uncertainty resulting from unanticipated changes in cost of available materials, labor, or capital. The cost of financing is linked to the project duration. The debt/equity ratio, the return on equity, cost of debt, the book life, and tax life are key factors that play an important part in the final cost estimate for the project.

4. Regulatory—Uncertainties in permitting, licensing, forthcoming environmental regulation and other regulatory actions.
5. Other—For example, labor disruptions or weather conditions.

As a technology moves along the continuum of development from R&D through commercial installation, the type of risk—and the corresponding uncertainty—tends to change. Figure 1-1 illustrates the sequence of steps and the potential impact on cost:

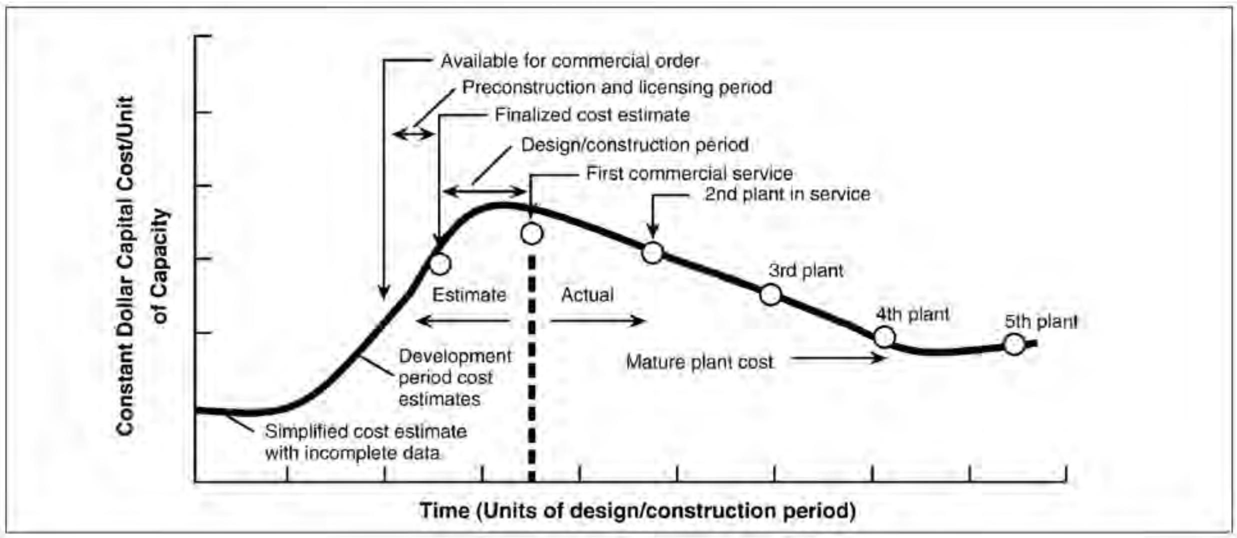

Figure 1-1
Capital Cost Learning Curve

At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The degree of uncertainty depends on the number of new and novel parts in a technology and the degree of scale-up required to reach commercial size.

Successful R&D efforts resolve many technical uncertainties, but others persist until initial demonstration. Examples of technical uncertainties that can remain include:

- Unanticipated interactions between system elements that previously were independently tested.
- Incompatibilities between materials or incompatibilities between utility operation and the industries from which the new technology was adapted.
- Unanticipated operating problems.

Demonstration and commercialization reduce technical and estimation uncertainties, but economic and other uncertainties always remain. The level of these uncertainties depends largely on the magnitude of capital investment, length of time for field construction, and number of regulatory agencies involved in the project.

1.5 Cost Calculation: Concepts and Terminology

This section explains key cost terminology and methodologies associated with capital and O&M cost estimates for new generation technologies.

1.5.1 Total Plant Cost versus Total Capital Requirement

Total Plant Cost (TPC), sometimes referred to as "Overnight Construction Cost," is developed on the theoretical basis of construction occurring at a single point in time. Total Capital Required (TCR) or "All-In Costs," include TPC plus owners costs and interest expenses during construction, often referred to as Allowance for Funds Used During Construction (AFUDC). The disparity between TPC and TCR is amplified when a generation technology demands a prolonged construction period – notably nuclear units – but is less pronounced for quick build technologies such as solar photovoltaic or simple-cycle combustion turbines. Many studies provide only Overnight Costs which may understate the total required capital investment.

1.5.2 Fixed and Variable Operating and Maintenance Costs

O&M costs for a generating unit are generally allocated as fixed and variable costs. Fixed operating and maintenance (FOM) costs are independent of number of hours of operation or amount of electricity produced, and are generally expressed in dollars per kilowatt per year ($/kW-yr). FOM includes operating labor, maintenance labor and equipment costs, and overhead charges, but generally excludes major capital improvements or plant retrofits Variable operating and maintenance (VOM) costs are those costs tied directly to power production and may or may not include fuel costs; otherwise, consumables are the principle cost component. VOM costs are generally expressed in mils per kilowatt hour (mils/kWh) (1 mil/kWh = $1/MWh).

1.5.3 Current versus Constant Dollars

Analysts can conduct an economic analysis in current dollars by including the effect of inflation on capital carrying charges and operating costs or in constant dollars by not including inflation in capital and operating projections. Care should always be taken when comparing cost estimates from different studies. An understanding of whether an estimate is in constant or current dollars, if it is on an overnight cost basis or includes AFUDC and escalation, and whether it includes site-specific costs or is a generic estimate is key to being able to accurately compare costs. However, if all bases are consistent when comparing different technology options, the most economical option will be apparent regardless of whether current dollar or constant dollar analysis is chosen. Current-dollar analysis more closely approximates future cash flows, which is important when utilities are reviewing estimates with regulatory authorities and securities analysts. Constant-dollar analysis gives a clearer picture of real cost trends and purchasing power differences. Constant dollars also present a more consistent comparative basis for projects with different operating lives. In any analysis, the inflation assumptions and the reference point for the dollar costs should be clearly and carefully identified where financial information is shown.

The choice of current or constant dollars depends on the purpose of the analysis. In general, studies involving the near term (the next 5 to 10 years) are best presented in current dollars. Longer term studies (20 to 40 years) may be best presented in constant dollars so that the effect of many years of inflation does not distort the costs to the point that they bear no resemblance to today's experience.

Table 1-1 and Figure 1-2 show the results of a cost comparison analysis conducted in the past. While the specific costs shown are for illustrative purposes only, the results show the difference between constant and current dollar estimates, as well as the difference between generic and site specific estimates. The generic estimates illustrate the difference between constant and current dollar estimates. On a total overnight cost basis, which is developed on the basis of construction occurring at a single point in time, the generic cost estimates in both constant and current dollars are the same. However, when the allowance for funds used during construction and escalation are calculated to arrive at the total capital required, the effect of including inflation in the current dollar estimate can be seen.

Table 1-1
Example Cost Estimate in Constant and Current $

Key Cost Elements	Generic Estimate Constant $	Generic Estimate Current $	Utility Site Specific Project Current $
Process Capital Cost (Equipment & Construction Labor)	2030	2030	2152[A]
General Facilities & Site Specific Costs	91	91	315[B]
Engineering & Construction Management	336	336	340
Contingency	459	459	470
Owners Cost	315	315	323
Total Overnight Cost (2007$)	**3231**	**3231**	***3600***
AFUDC	749	1220[C]	1837[D]
Escalation	0	937[E]	892
Total Capital Required	**3980**	**5388**	**6329**

[A] Reflects utility's design specification for reliability and other preferences
[B] Includes site specific requirement for transmission, security, raw water, etc.
[C] Short term project financing at 8.5%
[D] Short term project financing at 11.4%
[E] Escalation at 2.5% per year

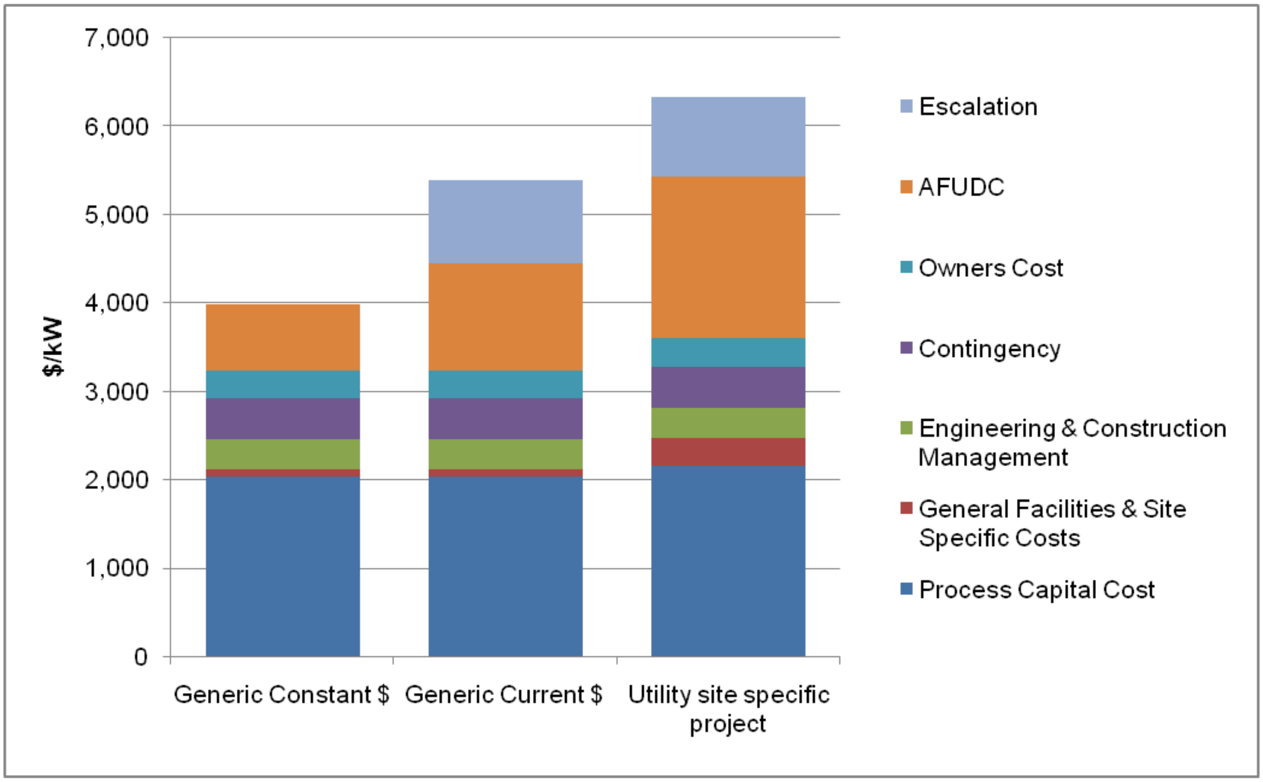

Figure 1-2
Comparison of Key Cost Elements in Constant $ and Current $ (*illustrative data only*)

Table 1-1 and Figure 1-2 also illustrates the difference between generic estimates, such as those included in this report, and a utility site specific project. As discussed in Section 1.3, site specific estimates will reflect the utility's philosophy regarding materials selection, equipment sparing, and unit layout. They will also include more detailed site-work requirements, interconnection requirements, and other details that generally lead to higher general facilities and site-specific costs. In addition, there may be differences in financing approach – the noticeable difference in AFUDC can be attributed both to a higher cost of financing and to what is known as "front-loading"; that is, a significant portion of the project financing is allocated in the first few years of the project, which accrues a larger interest than if it were allocated in "middle-loading" or "back-end-loading".

In this report, the constant dollar method is used so that the technologies are presented on a consistent cost basis regardless of actual project lead time, meaning the disparities in construction duration requirement for the plants are normalized. This approach is valuable for consideration of the long-term role of technologies in the future generation mix. For example, the two year construction schedule for a wind turbine farm and the ten year construction schedule for a nuclear reactor are taken into account by working backwards from the commercial service date thus avoiding the effect of inflation in the analysis. In actual practice, as electricity system load requirements dictate needs for new generation capacity, technologies with different project schedules will be implemented based on their economic viability to complement the existing system. Thus, the preferred analytical approach may differ from one project to another.

1.5.4 Levelized Cost of Electricity (LCOE)

The levelized cost of electricity (LCOE) represents an annualized cost of generating electricity over the lifetime of the unit, including initial capital, return on investment, and costs of operation, fuel and maintenance. LCOE calculations are based on assumptions regarding future unit operations, operating costs, fuel prices, financing terms, and inflation. Figure 1-3 is an LCOE graph for a natural gas combustion turbine combined cycle. Note that busbar cost is synonymous with LCOE in these figures. In contrast, Figure 1-4 presents LCOE for solar parabolic trough. In the former, fuel is the chief cost component, whereas in the latter, the up front capital costs comprise a majority of the LCOE.

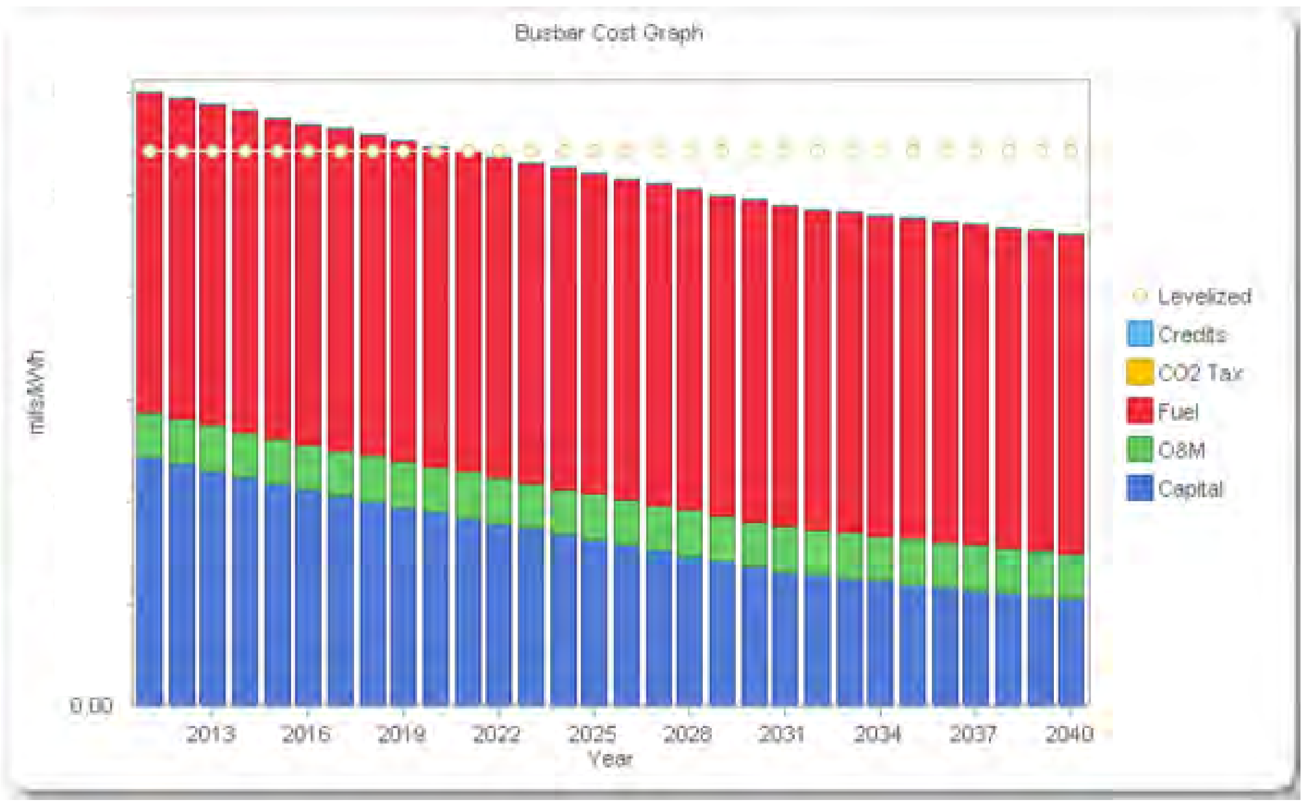

Figure 1-3
Example LCOE for Natural Gas Combustion Turbine Combined Cycle [4]

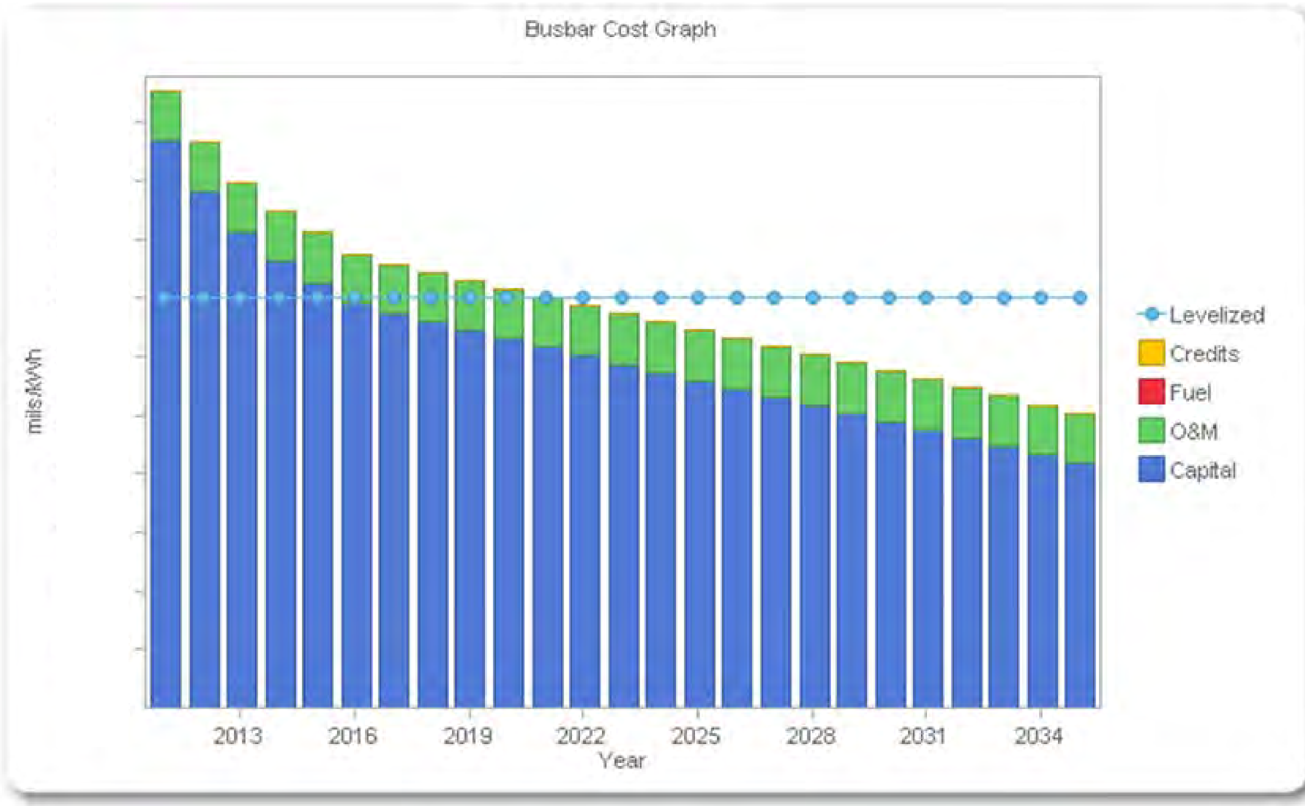

Figure 1-4
Example LCOE for Solar Parabolic Trough [4]

1.6 Treatment of Government Incentives

At the federal level, a number of policies provide financial incentives to development of power generation technologies. These include investment and production tax credits, loan guarantees, and accelerated depreciation under the U.S. Internal Revenue Service Modified Accelerated Capital Recovery System (MACRS). Except for MACRS, most U.S. federal incentives are authorized for a limited number of years and can change frequently. Consequently, with the exception of MACRS, tax credits and loan guarantees have not been included in the estimates of capital and levelized costs of electricity that are provided in this report.

The MACRS includes provisions for accelerated depreciation of all commercial-scale power generation technologies presented in this report.[**5**] Established to promote corporate capital investment, accelerated depreciation reduces total project costs by delaying the tax burden through deferred income taxes. MACRS depreciation schedules for power generation projects range from 5 years for commercial solar, wind and geothermal projects to 20 years for coal plants and other steam generation. Appendix A summarizes MACRS depreciation durations for technologies presented in this report.

1.7 Representative Cost and Performance of Power Generation Technologies

Estimates of the representative cost and performance of power generation options are presented in Table 1-2 for 2015 and Table 1-3 for 2025. Financial and technology-specific assumptions included in the calculations of the levelized cost of electricity estimates are presented in Appendix A.

Table 1-2
Representative Cost and Performance of Power Generation Technologies (2015). See Appendix A for financial assumptions.

All Costs in Constant Dec. 2010$	Nominal Plant Capacity, MW	Capacity Factor, %	Book Life[1], Years	Heat Rate, Btu/kWh	CO_2 Emissions[2], Metric Tons/MWh	Total Plant Cost, $/kW	Total Capital Required[3], $/kW	FOM, $/kW-yr	VOM, $/MWh	Fuel Price, $/MMBtu	LCOE[4], $/MWh
Coal: PC[5]	750	80%	40	8,750	0.84	2000 - 2300	2400 - 2760	48	2	1.8 - 2.0	54 - 60
Coal: IGCC[5]	600	80%	40	8,940	0.86	2600 - 2850	3150 - 3450	74	2.3	1.8 - 2.0	68 - 73
Natural Gas: NGCC[6]	550	80%	30	6,900	0.37	1060 - 1150	1275 - 1375	16	2.3	4 - 8	49 - 79
Nuclear	1400	90%	40	10,000	-	3900 - 4400	5250 - 5900	110	1.7	0.4 - 0.8	76 - 87
Biomass, Bubbling Fluidized Bed	100	85%	40	12,900	0[7]	3500 - 4400	4000 - 5000	63	5	2 - 6	84 - 147
Wind: On-shore	100	28 - 40%	20	-	-	2025 - 2700	2120 - 2825	35	-	-	75 - 138
Wind: Off-shore	200	40%	20	-	-	3100 - 4000	3250 - 4200	105	-	-	130 - 159
Solar: Concentrating Solar Thermal (CST)	100 - 250	25 - 49%	30	-	-	3300 - 5300	4050 - 6500	64 - 68	-	-	151 - 195
Solar: Photovoltaic (PV)	10	15 - 28%	20	-	-	3400 - 4600	3725 - 5050	50 - 65	-	-	242 - 455

Table 1-3

Representative Cost and Performance of Power Generation Technologies (2025). See Appendix A for financial assumptions.

All Costs in Constant Dec. 2010$	Nominal Plant Capacity, MW	Capacity Factor, %	Book Life[1], Years	Heat Rate, Btu/kWh	CO_2 Emissions[2], Metric Tons/MWh	Total Plant Cost, $/kW	Total Capital Required[3], $/kW	FOM, $/kW-yr	VOM, $/MWh	Fuel Price, $/MMBtu	LCOE[4], $/MWh
Coal: PC with Carbon Capture[5,8]	600	80%	40	9,840 - 11,800	0.09 - 0.11	3200 - 4100	3850 - 4920	79	3.8	1.8 - 2.0	87 - 105
Coal: IGCC with Carbon Capture[5,8]	500	80%	40	9,100 - 11,000	0.09 - 0.15	3100 - 3800	3750 - 4600	97	3.3	1.8 - 2.0	85 - 101
Natural Gas: NGCC[6]	550	80%	30	6,320	0.34	1060 - 1150	1275 - 1375	16	2.3	4 - 8	47 - 74
Natural Gas: NGCC with Carbon Capture[6,8]	450	80%	30	7,140 - 8,000	0.04	1600 - 1900	1900 - 2250	30	6.5	4 - 8	68 - 109
Nuclear	1400	90%	40	10,000	-	3800 - 4250	5100 - 5700	110	1.7	0.4 - 0.8	74 - 85
Biomass, Bubbling Fluidized Bed	100	85%	40	11,400	0[7]	3400 - 4250	3900 - 4850	63	5.0	2 - 6	80 - 136
Wind: On-shore	100	28 - 40%	20	-	-	1960 - 2600	2050 - 2720	35	-	-	73 - 134
Wind: Off-shore	200	40%	20	-	-	2850 - 3650	3000 - 3825	105	-	-	122 - 147
Solar: Concentrating Solar Thermal (CST)	100 - 250	26 - 58%	30	-	-	3000 - 4800	3700 - 5900	62 - 68	-	-	116 - 173
Solar: Photovoltaic (PV)	10	15 - 28%	20	-	-	2900 - 3950	3175 - 4325	50 - 65	-	-	210 - 396

[1] Book Life refers to the operating life of the plant. Debt life assumptions are provided in the Appendix, Table A-2.

[2] CO_2 emissions are for power generation only, not life cycle emissions.

[3] Total Capital Required is based on overnight capital costs plus estimated project/site-specific costs and owner's costs. Finite escalation (i.e., beyond 2010) is not included. Does not include production tax credits, investment tax credits, loan guarantees or other incentive programs

[4] Levelized Cost of Electricity (LCOE) includes estimated capital costs, fuel costs, and VOM and FOM costs. Financing rates are based on Investor Owned Utility (IOU) financial assumptions (see Appendix A). Since the LCOE is based on a constant dollar (Dec. 2010) basis, no inflation/escalation for fuel, capital cost and O&M is assumed. Does not include production tax credits, investment tax credits, loan guarantees or other incentive programs, nor major capital refurbishments or decommissioning costs (except for Nuclear, which includes a $1/MWh federal nuclear waste fund fee in the variable O&M).

[5] Sulfur oxides (SO_x)/hydrogen sulfide, nitrogen oxides (NO_x), particulate matter and mercury emissions controls are included in the coal technology estimates.

[6] 80% capacity factor for NGCC assumed for comparison of all fossil technologies on potential as baseload generation technology options

[7] Biomass emissions can vary significantly based on fuel source and life-cycle emission assumptions. Conventionally, the release of carbon from biogenic sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net CO_2 emissions over some period of time. However, if increased use of biomass energy results in a decline in global carbon stocks, a net positive release of carbon may occur. (See discussion in section 5.3)

[8] LCOE includes transportation and storage cost of $10/metric ton CO_2 which, on a per MWh basis, adds $3, $6 and $7 to NGCC, IGCC and PC respectively.

2
COAL

2.1 Description

While there is substantial regional variation within the U.S. in the proportion of electricity served by coal, coal-fired generating units represent 31% of U.S. domestic installed capacity. Traditionally, most of these coal-fired units were heavily utilized to provide baseload levels of generation; however the current low price of natural gas has pushed some coal plants down in the dispatch order. Combined with the recession-driven drop in electricity consumption, annual U.S. coal-fired generation declined 11% in 2009. Even so, coal-fired units supply 45% of domestic power, and due to the high carbon intensity of coal, emit over 80% of electric sector-related CO_2. [6]

In the last decade, a large number of coal plants initially planned to be built have since been cancelled. Contributing factors include: increased capital requirements, potential federal climate policy, forthcoming Environmental Protection Agency (EPA) regulations principally impacting coal-fired generating units, rising coal transport fees, the shale gas boom leading to the resultant decline in natural gas prices, and mounting public opposition to coal-fired power plants. It is likely that future coal plants will ultimately have to include CO_2 capture and storage (CCS). However, utility-scale CCS deployment will not occur until several technical, political and legislative issues are resolved:

- Establishment of clear CO_2 emission rules
- Demonstration of CCS technologies at utility scale, e.g. >1 million tons of CO_2 per year stored in multiple geologies
- Public acceptance of CO_2 sequestration in multiple geologies
- Resolution of the issue of long-term liability for stored CO_2
- Establishment of a price (and trajectory) for CO_2 emissions

2.1.1 Pulverized Coal (PC)

Pulverized coal (PC) units provide nearly all of domestic coal-fired capacity. In the U.S., most PC plants have used standard, subcritical operating conditions with main steam typically at 540°C (1,000°F)/16MPa (2,400 psi). However, the past twenty years have yielded significant improvements in materials for boilers and steam turbines and a much better understanding of cycle water chemistry. These improvements have resulted in an increased number of new plants employing supercritical (SC) and ultra-supercritical (USC) steam cycles around the world. SCPC plants are defined by main steam conditions above 540°C (1,000°F)/22MPa (3,200 psi), while USC PC plants generally operate at main steam conditions above 595°C (1,100°F)/24MPa (3,500 psi). Materials for Advanced USC PC plants up to 700°C-760°C (1,300°F-1,400°F)/35 MPa (5,000 psi) are also in development, although no plants have been built to date. With their lower operating temperature and pressure, traditional subcritical steam plants typically achieve a heat rate of 9,500-10,600 Btu/kWh, compared to the higher temperature and pressure SC plants that typically achieve 8,500-9,500 Btu/kWh and USC plants that may achieve heat rates between 7,600-8,500Btu/kWh. Advanced USC plant designs are estimated to have heat rates in the 6,800-7,600 Btu/kWh range. In the last ten years, significant improvements also have been achieved in reducing heat losses in the low-pressure end of steam turbines, improving both efficiency and reliability of the overall generating unit.

2.1.2 Integrated Gasification Combined Cycle (IGCC)

IGCC technology uses solid and/or liquid fuels – typically coal, petroleum coke, petroleum residuum, biomass, or a blend of these fuels – in a power plant that leverages the environmental benefits and thermal performance of a gas-fired combined cycle. In an IGCC gasifier, a solid or liquid feed is partially oxidized with air or high-purity oxygen. The resulting hot, raw “syngas” – an abbreviation for synthesis gas – consisting of carbon monoxide (CO), CO_2, hydrogen gas (H_2), water, methane (CH_4), hydrogen sulfide (H_2S) and other sulfur compounds, nitrogen gas(N_2), and argon (Ar). After it is cooled and cleaned of particulate matter and sulfur species, the syngas is fired in a combustion turbine (CT). The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine.

The use of a gas turbine/steam turbine combined cycle helps gasification-based power systems achieve competitive power generation efficiencies, despite energy losses during fuel conversion, in the gasification system, and in the air separation unit (ASU) in oxygen-blown systems. In a typical IGCC unit, about 60% of the net power output is generated by the gas turbine(s) and about 40% by the steam turbine. State-of-the-art IGCC configurations for bituminous coal are expected to achieve overall thermal efficiencies in the range of 8,300-9,000Btu/kWh — comparable to supercritical PC units. By removing the pollution-forming constituents from the pressurized syngas prior to combustion in the power block, IGCC plants can meet extremely stringent air emission standards.

Worldwide there are five coal-based and nine heavy oil-based IGCC plants in operation. In the U.S. there are two coal-based plants in operation, two under construction and two others in advanced development. China has two coal-based IGCC plants under construction and several other IGCC plants are being developed worldwide.

2.2 Coal Resources

There are several measures for domestic coal reserves, based on various degrees of geologic certainty and economic feasibility. Published data range from how much is left at currently producing mines to total coal resources, which is an estimate of how much coal is likely to exist, both known and that which is postulated based on geological principles. As of January 1, 2009, the “recoverable reserves at producing mines” was 17.9 billion short tons.[1] Using a broader category of reserves, “estimated recoverable reserves" – which includes all coal that can be mined with today’s mining technology, after accessibility constraints and recovery factors – this amount increases to 261 billion short, which based on U.S. coal consumption for 2008,

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[1] One short ton equals 2000 pounds.

represents enough coal to last 234 years. Still, this amount represents only a fraction of estimated total resources, see Figure 2-1. [7]

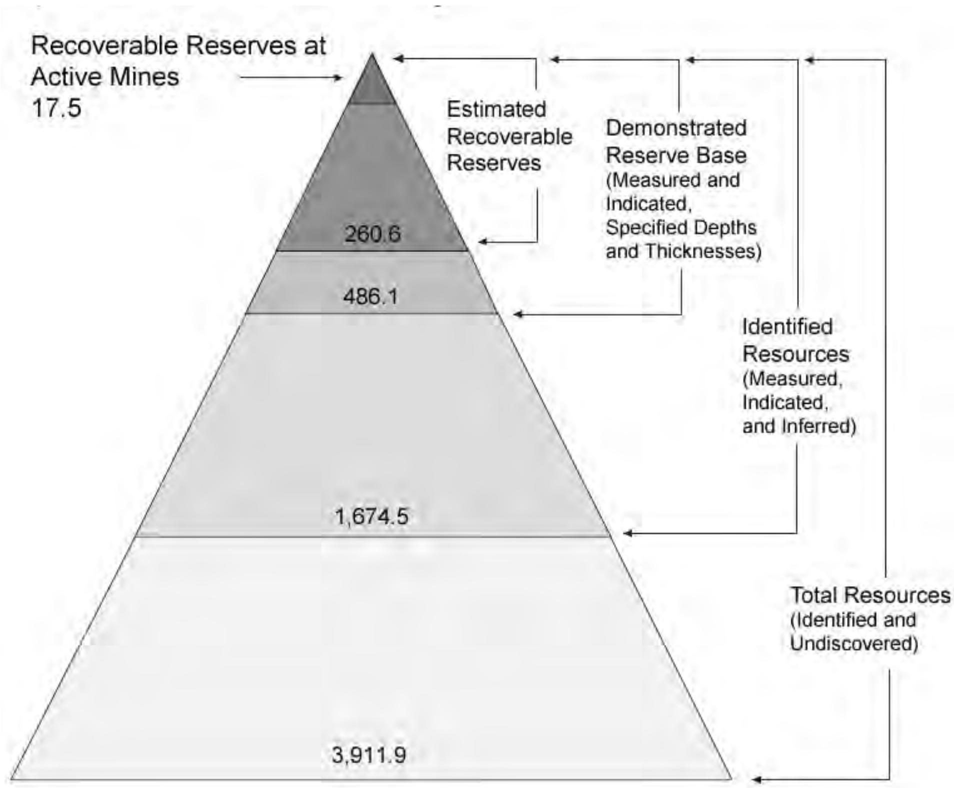


Figure 2-1
U.S. Coal Resources and Reserves (Billion short tons as of January 1, 2009) [7]

There are four major ranks (types) of coal. In the United States, coal rank is classified according to its heating value, its fixed carbon and volatile matter content, and other factors. The coal ranks from highest to lowest in heating value are: anthracite, bituminous, subbituminous and lignite. Coal plants are configured to combust a particular rank of coal possessing additional specified characteristics.

The power sector accounts for 95% of domestic coal demand. Coal is not a national commodity with a uniform price. Primary cost drivers are plant location, coal rank and supply region, and coal contract terms. In some regions, transportation costs comprise half of the delivered price, effectively segmenting the market by producing region. Low-sulfur Appalachian coal is usually twice the delivered cost of Powder River Basin (PRB) coal. The entire coal supply chain is planned around *ratable take* – that is, steady monthly deliveries contracted one to five years in advance.

Utilities plan coal purchases around baseload generation, acquiring 80-90% of their supply via multiyear contracts Seasonal variation in coal burn and plant outages are managed through coal stockpiles, typically measured in burn days. Low gas prices have pushed less economic coal units down the merit order, causing some to follow changes in load more frequently. Impacted coal plants are seeing a lower, and less predictable, coal burn rate, leading them to decrease their ratable coal take and lose the efficiencies from steady and predictable mine operations, while increasing their exposure to the spot market. Concurrently, coal stockpiles, as a function of burn days, must increase in order to absorb burn swings. Companies facing greater instability in their loads will therefore incur greater fuel costs than otherwise. In a new coal plant, the fuel costs can account for 25 to 30% of the levelized cost electricity. For existing plants, this fraction can be even higher.

Coal and transportation companies both rely on ratable take. Mine operations entail high capital investments which are best justified with predictable, steady shipments. Large mines, which typically run 24x7 to maximize use of the expensive mining equipment, cannot efficiently swing production to match coal demand. Barge and railroad companies schedule delivery around the regular back and forth cycle from mine to plant.

2.3 Environmental Considerations

2.3.1 Greenhouse Gas Emissions

In anticipation of future climate regulations, the power sector is supporting development and demonstration of technologies to decrease CO_2 emissions from electric generation. For coal-fired generation, the two main strategies for decreasing CO_2 production are through 1) efficiency gains, and 2) CO_2 capture and storage (CCS).

The higher operating temperatures and pressures for USC PC plants, discussed in the previous section, are one approach to increasing the efficiency of a plant, thereby, decreasing the CO_2 output per MWh generated. Net plant efficiency for steam plants is estimated to improve by 0.16% for every 0.7MPa (100-psi) increase in main steam pressure and by 0.16% for every 5.6°C (10°F) increase in the main steam temperature. The increase in efficiency from a subcritical plant to an USC plant is estimated to reduce CO_2 emissions by 15 to 30%. Of course, this reduction also would apply to emissions such as sulfur dioxide (SO_2) and nitrogen oxides (NO_X) since the more efficient plant would fire less coal to produce the same energy.[2]

While CCS is not yet commercially available for full scale PC plant application, post combustion CO_2 capture based on amine separation technology is one promising process that has been used in the petrochemical and natural gas processing industries to separate CO_2 from a gas stream. The general process works as follows: CO_2, which comprises about 10 to 15% of the exiting flue gas, would be captured from the flue gas downstream of other environmental control systems using a solvent. The solvent would be heated and recycled, and the heating will drive off the CO_2. The CO_2 stream is then dehydrated and compressed to 10 MPa (1,500 psi) or greater for transport to permanent sequestration. The challenge of applying this technology to a coal-fired plant is the low concentration of CO_2, low pressure of the gas stream, and particulate and SO_2/SO_3 impurities present in the flue gas, which can hinder the amine solvent. The energy cost of the current amine solvent regeneration and CO_2 compression can reduce the plant output by about 30%. However there are several promising improvements in alternative sorbents, membranes, etc. that are targeted at significant reduction of this energy penalty.

An advantage of gasification-based energy systems (i.e. IGCC) relative to pulverized coal combustion is that the CO_2 produced by the process is in a concentrated, high-pressure gas stream where the partial pressure of CO_2 is much higher than that in flue gas from SCPC plants.

This higher pressure makes it easier and less expensive to separate and capture CO_2. Once the CO_2 is captured, it can be compressed and sequestered (prevented from escaping to the atmosphere). CO_2 capture from gasification plants is currently commercially practiced in the U.S. and worldwide. However, the operation of an IGCC plant with capture and firing the hydrogen rich gas in the gas turbine has yet to be commercially demonstrated. The latest LCOE estimates for IGCC and PC plants without capture show higher cost for IGCC; however when capture is added, the COE estimates of IGCC and PC are very similar. The preference will depend on the specifics of location, coal type and technology readiness.

2.3.2 Non-GHG Considerations

Continuous emissions monitoring systems ensure compliance with local, state and federal clean air standards. Air quality control system designs will be affected by recent discussions and potential changes in water discharge requirements, requirements for CO_2 capture systems, potential regulation of Toxics Release Inventory-reportable substances, and regulation of metals and even bio-accumulative toxicants (cadmium, chromium, lead, selenium).

Pollutant control technologies for PC plants can consist of the following gas treatment steps: selective catalytic reduction for NO_x control, an electrostatic precipitator (ESP) or fabric filter for removal of particulate matter, activated carbon injection with a fabric filter for mercury control, a dry or wet flue gas desulfurization (FGD) scrubber for SO_2 removal, and a wet ESP for SO_3 control.

The IGCC technology is able to achieve lower pollution emissions because the pollutant constituents formed in gasification can be removed prior to combustion in the gas turbine and under high pressures. Sulfur impurities in the feedstock are converted to hydrogen sulfide and carbonyl sulfide, which are removed from the syngas to ultimately produce either elemental sulfur or sulfuric acid. NO_x is not formed in the oxygen-deficient gasifier. Rather, ammonia and hydrogen cyanide are created by nitrogen-hydrogen reactions. The hydrogen sulfide, ammonia, hydrogen cyanide, and particulate matter are removed from the syngas prior to combustion. Mercury speciation in IGCC has yet to be completely characterized. However, at the Eastman coal gasification plant, the use of sulfur impregnated activated carbon beds in the syngas stream at ambient temperatures prior to the sulfur removal process captures 90 – 95% of the mercury.

2.4 Technology Status

Table 2-1
Technology Status – Pulverized Coal (PC)

	Supercritical PC	Ultra-Supercritical PC	Advanced Ultra-Supercritical PC
Operating Conditions	3200-3500 psig, 1000-1050°F	3500-4500 psig, 1100-1150°F	5000 psig, 1300-1400°F
Major Trends	O&M comparable to subcritical. Existing units: fuel switching, life extension, & steam turbine upgrades.	New alloys – higher temperature & pressure. Sliding pressure design. Second reheat added to steam cycle.	
Resource Requirements that Impact Technology	Economics & practicality not favorable for low grade coals (coals with HHV less than 6,000 Btu/lb) Increasing price of alloys for pressure parts & FGD absorbers.	Same as Supercritical	Cost & development of 1300°F high chrome & nickel alloy pressure parts.
Key Issues	Upgrading existing units. Impact of pending climate policy. Public opposition to coal-fired units. Difficulty in obtaining financing. Reducing capital cost. Improving performance, availability, & cycling capability. Improved integration with emission control systems Breakthrough in economical CO_2 removal or reduction.	Impact of pending climate policy. Breakthrough in economical CO_2 removal or reduction.	Willingness of US, Japanese & European OEMs to continue R&D into efficiency improvements given pending climate policy.
Key Market & Business Indicators	Competition from NGCC. Uncertainty regarding CCS regulation/legislation	Global market for procuring equipment.	

Table 2-2
Technology Status – Integrated Gasification Combined Cycle (IGCC)

	Current IGCC Technology	Advanced IGCC technology
Major Trends	Standardized designs to reduce cost & construction time. Fuel flexibility.	Higher temperatures in CT & steam cycle of combined cycle.
Changes to Watch for	More integration between combustion turbine gas compression & air separation unit.	Methods to reduce power requirements associated with O_2 production &, if CO_2 emissions become controlled, power for CO_2 removal & compression.
Other Characteristics	Integration of CT compressor & ASU.	Advanced integration CT, ASU, & emissions controls.
Resource Requirements that Impact Technology	Increasing price of alloys for pressure parts & vessels. Ability to gasify lower grade coals more cost effectively.	Increasing price of alloys for pressure parts & vessels. Ability to gasify lower grade coals more cost effectively.
Key Issues	Reducing capital cost. Improving performance, availability, & cycling capability. Demonstration of viability with low-rank coals. Competition from PC.	Reducing capital cost. Improving performance, availability, & cycling capability. Competition from PC & CFB.
Key Market Indicators	Increased escalation of materials & equipment has resulted in significant increases in plant costs & cancellation of a number of projects. Uncertainty regarding CCS regulation/ legislation	
Key Business Indicators	Global growth & market for purchasing equipment. Future price of natural gas & competition from NGCC. Competition from PC & CFB.	Global growth & market for purchasing equipment. Willingness of US DOE & OEMs to continue R&D into efficiency improvements with regulatory climate resulting from concerns over global warming.

3
NATURAL GAS

3.1 Description

Natural gas-fired simple-cycle combustion turbine (CT) and combustion turbine combined-cycle (CTCC) –referred to here as natural gas combined cycle (NGCC) – power plants are a mature generation technology representing about one-fourth of the electricity generated in the United States. In both 2009 and 2010, new natural gas-fired units provided about 10 GW of incremental capacity, which is more than any other single fuel source. There is significant regional variation in reliance upon natural gas-fired power generation. [6]

Gas-fired generation technologies have the unique distinction of relatively reliable and efficient performance throughout the duty spectrum of power plant operation. These include emergency or black start capability, peaking duty, intermediate or cycling duty, and base load operation. The range of available frame sizes also provides operating capability from several hundred kilowatts to over 300 megawatts in simple-cycle operation and over 800 MW in combined-cycle operation. When compared to coal-fired units, gas-fired units entail shorter installation times, lower emissions, and lower total plant cost. NGCCs demonstrate some of the highest plant efficiencies currently attainable along with high plant availability. Key issues include long-term natural gas availability and pricing uncertainty/volatility, transmission limitations, site space availability (more so for NGCC), method of heat rejection in light of pending minimum water discharge regulation, and operational flexibility – especially fast start capability and a lower minimum load.

3.1.1 Combustion Turbine

A combustion turbine, also called a gas turbine (GT), includes an air compressor, a combustor, and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustor, producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the CT is coupled to an electric generator such that mechanical energy produced by the CT drives the electric generator. The power output of the combustion turbine is very sensitive to ambient temperature. This operational sensitivity is particularly relevant as nearly all peaking units are gas-fired CTs, and peak power days tend to coincide with heat waves.

Turbine efficiency is strongly influenced by the expansion turbine inlet temperature. Earlier designs of CTs for stationary applications (heavy duty) had maximum inlet temperatures of approximately 2000°F. More recent CT designs have turbine inlet temperatures exceeding 2500°F. This higher inlet temperature reduces the heat rate by about 10%.

Because this report focuses on baseload technologies, the cost and performance of peaking units, including CTs, have not been included.

3.1.2 Natural Gas Combined Cycle (NGCC)

An NGCC is a CT combined with a Rankine steam cycle. The hot exhaust gas from the CT passes through a heat recovery steam generator (HRSG) where it exchanges heat with water, producing steam. Significant improvements are realized in both efficiency and electrical output over the CT. Consequently, NGCCs are typically operated at either intermediate duty (20 to 65% capacity factor) or baseload (65 to 90% capacity factor).

NGCC units with outputs of 100 MW to 800 MW achieve heat rate ranges from 6,300-7,600 Btu/kWh. [2] This heat rate range is up to 50% better than a supercritical pulverized coal unit. With natural gas currently at about $4.50 per MMBtu, 10 year price projections at $6/MMBtu, and forthcoming environmental regulations principally directed at coal-fired generation, NGCC units are expected to displace some amount of baseload coal.

3.2 Natural Gas Resources

Natural gas price (and availability) is a key component in the levelized cost of natural gas power. The shale gas boom has ushered in a new economic paradigm for natural gas-fired power. The emergence of these new supply sources has led to an unprecedented, though necessary, expansion of the transmission pipeline network, resulting in natural gas at a delivered price that is both low and nearly independent of geography. Concerns surrounding natural gas prices persist because substantial increases in new natural gas generating units may produce higher prices due to higher demand that will continue well beyond the duration of current natural gas forward price curves.

3.3 Environmental Considerations

The major emissions from NGCCs are nitrogen oxides (NOx) and carbon monoxide (CO). NOx emissions are generally controlled by Selective Catalytic Reduction (SCR); similarly, CO is also controlled by a catalyst. Like coal-fired units, gas-fired units are fit with continuous emissions monitoring systems to ensure compliance with local, state and federal clean air standards. Natural gas combined cycle generation produces less than half as much carbon dioxide as coal-fired power.

3.4 Technology Status

Table 3-1
Technology Status – Combustion Turbine Combined Cycle

	State of the Art Heavy-Duty Combustion Turbines	State of the Art Aero-Derivative Combustion Turbines	Advanced - Heavy-Duty Combustion Turbines on Natural Gas (NG)
Major Trends	2,500+°F firing temperature (turbine rotor inlet temperature). Some aero features. Dry low-NO_x combustor. External cooling of cooling air. Higher capacity and pressure ratio.	2,550°F firing temperature (LMS100). Industrial cogeneration. Quick delivery of pre-packaged units. Off-site over-hauls Dry low-NO_x combustor.	2,600°F firing temperature. Steam cooling system. 3-D compressor airfoils, improved air cooling of turbine blades, advanced thermal barrier coatings, seals
Changes to Watch for	Modest upgrades to provide low cost alt to Advanced Turbines.	Uprating of existing units. Higher availability due to replacement units. Long-term performance & reliability of LMS-100.	More aero features. Catalytic combustion. Improvements & higher temperatures in HRSGs (new alloys for pressure parts).
Market Restructuring & Deregulation	Favors NGCC over traditional coal/ nuclear for new base-load due to better short-term economics or concern over global warming (PC-fired plants).	Cogeneration improves economics & assures much higher efficiency than traditional central power plant.	
Key Issues	Advantage of low capital cost & high CC efficiency.	Advantage of industrial cogeneration at high power/heat. Quick overhaul turnaround.	Price of natural gas. Possible future inroads for IGCC application.
Key Market and Business Indicators	Growth in peaking and cycling power generation. Impact on capital cost & plant performance if CO_2 removal is mandated. High output with high efficiency in cycling duty service.	Growth in industrial cogeneration. Impact on capital cost & plant performance if CO_2 removal is mandated. High output with high efficiency in cycling duty service. Provide grid stability for integration of variable, renewable generation.	Rise in NG prices may justify investment in more CT R&D. Impact on capital cost & plant performance if CO_2 removal is mandated.

4
NUCLEAR

4.1 Description

Nuclear power is a mature technology representing approximately 20% of the electricity generated in the U.S. [6] and close to 14% of the electricity generated in the world.[8] It has been especially attractive to countries with limited access to indigenous fossil fuel supplies, such as Japan and France, where it provides approximately 24% and 77% of their respective total electricity needs. There are currently about 440 reactors in operation in 29 countries and 65 reactors under construction throughout 15 countries. The major factors driving today's interest in nuclear power include projected growth in electricity demand, nuclear power's zero greenhouse gas emissions profile, and increased desire for energy security.

Compared to other large-scale central stations, nuclear plants are generally more expensive to construct, but less expensive to operate. Higher construction costs are mainly associated with safety and security requirements, including both design/construction requirements and the lengthy licensing process. Low operating costs are a result of lower fuel costs (on a per kWh basis). Therefore, nuclear plants can be cost effective when construction costs are kept in check and when they are operated at high capacity for many years. Due to the low percentage that fuel costs contribute to overall operating costs (~ 10% of new plant costs), electricity generated from nuclear reactors has historically been more stable than that of coal- or natural gas-fired plants, where fuel costs dominate operating costs making them more volatile as a result of changing fuel prices.

Nuclear power is generated through sustained fission of uranium atoms. The heat produced during fission is transferred via gas or liquid to produce steam. Light water reactors (LWR) use standard water as the heat transfer medium and neutron moderator. The water slows fast neutrons resulting from prior fission events to energy levels at which the probability of new fission events is greatly increased. Less commonly used moderators in non-LWR reactor designs include heavy water and graphite. Fast neutron reactors do not require a moderator, and utilize a variety of coolants.

The current 104 LWRs operating in the U.S. today consist almost entirely of two primary types: pressurized water reactors (PWRs) and boiling water reactors (BWRs). PWRs utilize pressurized water as the coolant, with separate cooling loops driving the steam turbine. BWRs allow the water in the cooling loop to boil, and this steam is then used to drive the steam turbine directly. PWRs and BWRs began to be installed in large numbers during the early 1970s, and comprise the vast majority of reactors in operation today around the world. These reactors generally utilize enriched uranium fuel, in which the proportion of a particular isotope of uranium is increased from that present in natural uranium through chemical processes. Advanced gas-cooled reactors (AGR) utilize graphite as a moderator and natural uranium for fuel. The CANDU reactor design also utilizes natural uranium fuel, and it uses heavy water as a moderator.

Newer nuclear reactor designs are actively being constructed and continue to undergo development today. Known as Advanced Light Water Reactors (ALWRs), these reactors are similar to the earlier BWR and PWR reactors with notable performance and safety advancements. Some ALWR reactor designs employ passive safety features rather than active ones, designed to increase reliability and safety. Research by EPRI and others has led to a technical basis for operation of BWRs, LWRs, and ALWRs for a period of 60 years. Over half of the current U.S. reactor population has received a 20 year extension of their operating license to 60 years.

An emerging category of reactors under development today are small modular reactors (SMRs). SMRs are generally considered to be designs less than about 350 MW. Several of these designs are derived from ALWR PWRs, however, they have fully integrated the steam generation function inside the reactor vessel itself. Because of this, the SMRs are sometimes referred to as Integral PWR designs. SMRs could be attractive due to lower capital costs and flexibility in how they could be deployed. Their smaller output could enable utilities to more closely match capacity additions to demand growth. In addition, their integrated design is small enough to be shop-fabricated and shipped to the site to facilitate on-site plant construction. Lastly, their lower absolute capital requirements can be spread over a period of time to reduce the financing challenges relative to larger nuclear plants, and revenues generated with the first units can help finance later units.

Advanced nuclear reactors designed to operate more efficiently based on more advanced fuel cycles may become commercially available in the 2030 timeframe. A characteristic of the advanced fuel cycles envisioned for these reactors would be reduced high-level waste, lower waste management costs, and reduced amounts of fissile material requiring security due to proliferation concerns. It is possible that these reactors could be capable of supporting high temperature hydrogen production, water desalination and other high temperature process heat applications.

4.2 Nuclear Fuel Resources

Uranium is the primary fuel used in light water and most other current reactor designs. Uranium is mined in a number of countries and must be processed into fuel before it can be used in a nuclear power plant. Global uranium resource estimates as of 2009 were more than 16 million tons, enough to supply the existing 370 GW global nuclear fleet for 300 years. [9] These estimates do not include civilian and military uranium stockpiles, reprocessed uranium and plutonium, re-enrichment of depleted uranium, or large unconventional uranium deposits (phosphorite deposits, seawater, etc.) that are currently uneconomic to extract. Currently, uranium from former weapons stockpiles alone supplies about 50% of the fuel requirements for U.S. nuclear power reactors.

Production of nuclear fuel assemblies used in light water nuclear reactors involves a number of industrial processes. Often called the “front-end” of the nuclear fuel cycle (i.e., before power production), fuel production involves:

- Uranium production – Mining, extraction, and milling to produce natural uranium ore and covert into natural uranium (U_3O_8)
- Conversion – Uranium concentrates are purified and converted to natural uranium hexafluoride (UF_6)
- Enrichment – Natural UF_6 is "enriched" to 3 – 5 % of the fissile uranium 235 (U-235) isotope, from approximately 0.7% U-235 in natural uranium
- Fuel fabrication – Enriched UF_6 is converted to solid uranium dioxide (UO_2) and then fabricated into ceramic fuel pellets that are contained in fuel rods. Fuel rods are then combined in an array to form a fuel assembly designed specifically for a reactor.

Some countries "reprocess" used nuclear fuel to remove remaining fissile U-235 and plutonium. These reclaimed fissile materials are combined with additional uranium to produce "mixed oxide" (MOX) fuel assemblies, which can be used in LWRs.

LWRs typically run on 18- to 24-month operating cycles, generally limited by nuclear fuel "burn-up" based on the level of fuel enrichment. LWR nuclear fuel assemblies usually remain in a reactor for three operating cycles, and one-third of the fuel is replaced after each operating cycle. Nuclear fuel "reloads" for a typical LWR plant can cost $100 - $150 million, depending on the price of uranium and cost of fuel processing and fabrication services.

4.3 Environmental Considerations

The three significant environmental considerations associated with nuclear power generation are: 1) storage of nuclear waste, 2) water use, and 3) low carbon emissions.

Nuclear plants generate both high and low level nuclear waste. These wastes require safe storage and disposal, which can be accomplished through various means including interim on and off site storage and permanent geological disposal. However, a national long-term repository high level nuclear waste remains unresolved.

A typical value for water withdrawal for nuclear power plants utilizing wet cooling towers is 720 gallons/MWh. The value for a once-through cooling system is given as 400 gallons/MWh and for a station utilizing pond cooling the values range from 400 to 720 gallons/MWh. The actual consumption rate for any given power plant will be dependent upon the plant's operating thermal efficiency, site ambient conditions, and intake water temperature. Potential water usage and fish protection regulations could create significant additional costs related to implementation of more advanced cooling technologies.

Nuclear plants produce no greenhouse gas emissions and have a lifecycle emissions profile comparable to wind and solar. Future federal clean air standards, CO_2 emissions regulations and/or carbon emissions taxes would contribute to nuclear power economic viability.

4.4 Technology Status

Table 4-1
Technology Status – Nuclear

	Commercial Power Reactors (LWR/CANDU/AGR)	Advanced Reactors (ABWR/EPR/ESBWR/ AP1000/SMRs, etc.)	Fast and/or Thermal Reactors (GFR, LFR, MSR, SFR, SCWR, VHTR)
Major Trends	Uprating of existing plants, increases in capacity factors by reducing the length of refueling outages, extension and renewal of operating licenses.	Move to Generation III/III+ designs with passive safety features, standardization of designs. Emergence of Small Modular LWR (45-200 MWe)	Collaboration between and within industry and governments, standardization of designs.
Changes To Watch For	N/A	Further development of smaller and medium sized light water reactors, 45-200 MWe.	Additional fuel cycle development – increasing burn up rates to reduce waste volumes and developing new fast reactor fuels to reduce waste toxicity.
Resource Requirements That Impact Technology	Uranium prices have increased dramatically over the last few years		Global governance of fuel cycle is not yet decided.
	High fossil fuel prices favor nuclear.	Limited availability of unique materials could be a constraint on rate of which growth could be sustained.	
Key Issues/Concerns	Safety and nuclear waste concerns led to poor public opinion.	Lengthy review, approval and construction processes, high capital costs	
		Global competition, potential shortage of workers with nuclear experience. Natural gas market conditions pose major short term competition to new nuclear	Engineering, materials, and fuel issues require further R&D to ensure reliable performance in a commercial setting.
Key Business and Market Indicators	Operating plants are applying for and receiving license extensions and power uprates.	17 COLAs filed for 26 units; currently, interest expressed for a total of 32 new reactors in U.S. 65 new reactors under construction outside U.S. DOE is developing a SMR program.	.
		Any CO_2 emissions regulations would favor nuclear.	

GFR = Gas-Cooled Fast Reactor, LFR = Lead-Cooled Fast Reactor, MSR = Molten Salt Reactor, SFR = Sodium-Cooled Fast Reactor, SMR = Small Modular Reactor, SCWR = Supercritical Water-Cooled Fast Reactor, VHTR = Very High Temperature Reactor.

5
BIOMASS

5.1 Description

With over 11 GW of installed capacity, grid-connected biomass power generation is second only to wind as the largest source of non-hydroelectric renewable electricity in the United States.[6] Power from biomass is a commercial electricity generation option providing dispatchable renewable power, the majority of which operates at baseload. Biomass energy is receiving increased attention as states establish their renewable portfolio standards (RPSs) and utilities continue to look for options to comply with these standards. However, biomass plants face significant challenges. Chief among them is uncertainty arising from concerns about carbon neutrality, forest sustainability, forthcoming environmental regulations – especially those pertaining to industrial boilers – and feedstock cost and availability.

The domestic biomass industry is dominated by facilities which are not connected to the grid – cogeneration plants that provide energy in the paper manufacturing sector. The ten largest biomass plants – with the largest at 128 MW – are cogeneration facilities owned by paper manufacturers, and the top five owners of biomass plants are companies involved in the paper manufacturing sector. [10]

For electric power generation, biomass is combusted through the following three methods:

1. Direct firing in dedicated biomass-fueled boilers;
2. Co-firing with coal in existing power plants; and
3. Repowering existing coal-fired units to 100% biomass.

Direct firing is accomplished using one of two technology choices: stoker grate and fluidized bed combustion (FBC). Stoker grate is a well proven, commercially available technology in which solid fuel particles rest on a grate to burn. In the FBC system combustion chamber, the biomass fuel and inert bed material are continually fed into the unit and are kept in suspension by an upward current of air and flue gas. FBC has the advantage of a lower combustion temperature, which reduces NO_x production. For both technologies, current research topics include metallurgy to address degradation of plant components due to alkaline earths and chlorine in the fuel.

Co-firing is currently the most common biomass option for electricity generation, presenting more than a dozen configuration options. In light of concerns over biomass supply security, co-firing provides the additional strategic value of allowing pure coal-firing when biomass supply is compromised. Co-firing statistics are limited, mostly due to the predominantly non-utility, industrial ownership of these plants. However, RPSs are prompting increasing interest from utilities. Key issues include boiler life and performance considerations, biomass handling and milling, environmental equipment performance, and health and safety.

Repowering of existing coal boilers to 100% biomass leverages existing assets such as site, transmission, staff, turbine generator, switch gear and more. It is considerably cheaper – on the order of 25-30%– than constructing a new unit, but its uncertain regulatory status, exposure to supply-based risks, and higher price than co-firing, may make it less attractive than co-firing.[11]

5.2 Biomass Resources

The diversity of available feedstocks makes biomass plants an option for many areas of the country. Currently, the major types of biomass resources used for generating electricity include, in descending order of importance:

1. Wood residues
2. Urban waste residues
3. Paper mill residues
4. Woody crops
5. Agricultural residues
6. Herbaceous energy crops
7. Animal and sewage waste

Each resource type involves different collection, transport, and post-harvest processing techniques, land requirements, regionality of supply, impacts on power production and power plant environmental performance.

Post-harvest processing options include drying, pelitizing and torrefaction. Using dry fuel increases overall thermal efficiency of a boiler since energy is not wasted vaporizing moisture in the fuel. Fuel also becomes easier to size and feed as moisture is removed. Innovative densification pre-treatments, such as pellitization, torrefaction, and conversion into bio-oil (e.g. by pyrolysis) may help to overcome the economically and environmentally challenging logistics of long distance biomass feedstock transportation. The commercial emergence of these pre-treatment methods could help facilitate a global international trade by reducing logistics costs.

In the long term, the potential for electricity generation from biomass will depend on technology advances as well as competition between feedstock production and other land uses, principally agriculture.

5.3 Environmental Considerations

Compared with coal, biomass feedstocks have lower levels of sulfur, sulfur compounds, and mercury, and demonstrations have shown that biomass co-firing with coal can also lead to lower nitrogen oxide emissions. Perhaps the most significant environmental benefit of biomass, however, is a potential reduction in carbon dioxide emissions.

Assumptions about the CO_2 emission intensity of biomass combustion is a difficult and somewhat controversial question. In their Annual Energy Outlook, the Energy Information Administration (EIA) excludes CO_2 emissions from the combustion of biomass from reported energy-related CO_2 emissions. [12] This is because the release of carbon from biomass combustion is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net CO_2 emissions over some period of time. However, the EIA and other analysts acknowledge that an increased use of biomass energy could potentially result in a decline in global carbon stocks, which could in turn result in a net positive release of carbon. If emissions from biogenic energy sources did not consider the offsetting sequestration of carbon dioxide associated with growing the feedstock, biomass carbon dioxide emissions could be as high as 1.14 metric tons/MWh. Furthermore, research shows that the full life-cycle CO_2 emissions from biomass, which account for emissions associated with growing, fertilizing, and harvesting the biomass feedstock, are not carbon neutral, and depend largely on the feedstock used and the application. For example, bioelectricity from wood has much lower life-cycle CO_2 emissions than ethanol from corn.

Though biomass may not be a carbon neutral fuel, it is generally agreed that it is greenhouse gas "beneficial", offsetting a large portion of CO_2 emissions compared to coal combustion. Taking into account biomass production, hauling, processing, fertilizer manufacture, feedstock conversion, and byproduct credits for greenhouse gas emissions and carbon sequestration, recent EPRI evaluations estimate that bioelectricity can offset 92-99% of greenhouse gas emissions (including CO_2, methane, and other greenhouse gases) for a range of biomass feedstocks when compared to coal production and combustion without carbon capture and sequestration. For this study, biomass CO_2 emissions are shown as zero metric tons/MWh, representing the zero net CO_2 emissions assumption.

Significant, ongoing regulatory uncertainty is hampering new biopower development, including: the U.S. EPA Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule, the Electric Generating Unit (EGU) Boiler MACT rule, the tailoring rule as applied to biogenic and anthropogenic carbon, and potential state and federal clean and renewable energy standards. The MACT rules are presently being revised, with final versions expected sometime in 2011. The tailoring rules initially excluded biogenic sources, but the EPA issued its final proposed tailoring rules in May 2010, reversing that stance by including biomass power plants. Development of the biomass wood industry will depend on whether the EPA decides to reverse or maintain its May decision. State-level RPSs do not handle biomass consistently. In addition, biomass has come under increasing debate as a variety of groups question forest sustainability practices and environmental impact considerations associated with wide spread use of biomass including intensive farming, over-use of fertilizers, chemicals use, and bio-diversity conservation.

5.4 Technology Status

Table 5-1
Technology Status – Biomass

	Biomass Power Generation System
Major Trends	Small to mid size units – stoker, mid to large size units – FBC. Trend towards co-firing with coal, combined heat & power, and co-generation
Changes to Watch for	More and more utilities exploiting biomass potential. Europe installing units larger than United States. Efficiency improvement
Resource Requirements that Impact Technology	Security of feedstock.
Key Issues	Reduced costs and fuel availability. Cost can be reduced by mass application and economy of scale. Not consistently addressed in RPS. US EPA: Tailoring rule, IB MACT.
Key Business Indicators	Price of natural gas, stricter emission limits, competition for feedstock, security of feedstock.

6
WIND

6.1 Description

With 40 GW, or 4% of domestic generating capacity, wind is the largest source of non-hydroelectric renewable electricity in the United States. As of the close of 2010, the U.S. is second to China in total installed wind capacity and annual capacity growth. After record-breaking growth in both 2008 and 2009, the U.S. wind industry in 2010 installed 5 GW of new wind power – an amount equal to half of the quantity in each of the previous two years. Likely factors contributing to this dramatic decline include a lack of power purchase agreements, the recession-driven credit crunch, unresolved transmission constraints, and the uncertainty regarding passage of a federal renewable energy standard. The global wind power market also experienced a slow-down in 2010. For the first time in 20 years, new worldwide installed capacity decreased by 5.8% with 35.7 GW of installation in 2010 compared to 37.9 GW in 2009. Worldwide, installed wind capacity in 2010 reached 195 GW, with a near term annual growth forecasted at 25%.[3] [6] [13]

To date, wind power's capital costs require tax incentives and subsidies for it to be a cost competitive energy source. With low current and forecasted natural gas prices, wind power's reliance on incentives is likely to persist.

Further challenges lie ahead for domestic wind capacity expansion. Large-scale grid integration may prove costly as wind is non-dispatchable and is frequently anti-correlated with periods of high electricity demand. Variability and uncertainty in wind power output present a unique challenge to the power system, demanding additional system flexibility and load-following from other generation assets. Its typically remote location – relative to load centers – frequently requires new transmission. Thus, high penetration of wind energy will have power system impacts that have to be managed through proper power plant interconnection, transmission planning, and system and market operations. Lastly, transporting wind turbine blades is increasingly challenging due to their ever increasing length.

In the U.S., wind projects typically are sized in the 100 MW range, utilize asynchronous double-fed induction generators sized between 1.5 and 2.5 MW, and experience a range of net capacity factors between 28 and 40%, depending on location. The largest wind plant in operation is the 735 MW Horse Hollow plant in Texas; a number of GW-scale plants are under development.

Though major wind turbine components are considered to be mature commercial technology, the technology continues to evolve and improve. Failures of gearboxes, blades, and other components continue to reduce the productivity of wind power plants. Several new technologies are being developed and applied to improve the reliability of the gearbox or eliminate the gearbox entirely.

The nameplate capacity of a wind turbine is determined by the manufacturer, but it can be approximated by the size of the generators being used. Individual designs range from less than 1 kW for remote sites with low power needs to machines up to 3 MW in size, and in the future may reach 5 MW. Average turbine size has steadily increased, with technological advances such as improved blade manufacturing technology, more sophisticated controls, and power electronics.

Wind turbines are designed to function within a wind speed window, which is defined by the "cut-in" and "cut-out" wind speeds. Once the wind reaches the cut-in speed, the turbine comes online and power output increases with the cube of wind speed, up to the speed for which it is rated. At the cut-out speed the turbine shuts down to prevent mechanical damage.

The capital cost to construct a wind farm varies depending on the resource type (wind class) and site specific conditions such as soil type, need for noise abatement and access to adequate transmission.

There is considerable uncertainty and variability in wind plant operation and maintenance (O&M) costs. The uncertainty is due to the scarcity of operating cost data for U.S. wind plants. Cost variability is principally driven by O&M strategy employed, the reliability of the equipment, the operating environment, and the roles and responsibilities of the equipment manufacturer in providing service and warranty repairs. The majority of the current installed wind power in the U.S. has been installed in the past five years and many of the projects are still being operated and maintained by the wind turbine suppliers for a fixed contract price – hence the lack of *actual* cost data. Five to eight years ago, five year warranties were available in the market; however, the trend in recent years among turbine suppliers is to reduce the term to two years and to eliminate operations tasks from the contract. Options are still available to extend the warranty period beyond the initial two-year term, but owners of large fleets tend to take over all turbine service, repairs and operations at the close of the warranty period.

The United States is poised to begin construction of its first off shore wind farm. In 2011, Cape Wind completed the permitting process for its proposed 468 MW wind farm to be located off of the Massachusetts coast. With global installed capacity at 2.5 GW, the technology of offshore wind power is still in its infancy.

6.2 Wind Resources

The power from wind varies proportionally with the cube of the wind speed, which has important bearing on the design and citing of wind turbines. As a result, even a small increase in wind speed can substantially boost the power available from wind. For example, a 25% increase in wind speed approximately corresponds to a doubling in the available power.

Accurate assessment of the quality of the wind resource at a proposed project site is a critical first step to the success of that project. Wind resource quality is characterized by wind speed and direction, the wind shear or variation of wind speed with elevation, and the intensity of turbulence. Within a known wind resource area, the wind generally exhibits seasonal, diurnal, and hourly variations. Prior to final site selection, the wind resource is measured for an extended period of time, usually two to three years, to statistically quantify the resource.

In the U.S., wind energy is divided into seven classes – with Class 1 being the lowest – based on the wind speed measured at a height of 50 m (164 ft) above grade. Currently, areas with wind speeds of Class 4 and higher are considered sufficient for wind power, with strong, frequent winds being the best for generating electricity. Because techniques of wind resource assessment have improved greatly, more detailed high-resolution wind resource maps have been developed. Wind is distributed unevenly around the U.S., with the upper Midwest providing the most potential.

Wind speeds increase at greater heights and winds are generally stronger at sea than on land. In addition, whereas land-based wind plants tend to produce peak power over night and during low demand times of year, the wind at sea is more uniform. Therefore, the power from offshore wind farms would be more valuable. However, offshore plants must account for factors such as wave and ice loading. One advantage of offshore wind turbines sited along the U.S. coastline is that the load centers would be closer to the offshore sites compared to the inland Class 4 or greater wind sites, due to the fact that the coastal areas tend to have a higher population concentration per square mile.

6.3 Environmental Considerations

Wind turbines themselves do not generate greenhouse gases and require no cooling water. Still, there are a variety of environmental issues associated with wind energy, namely: land use, visual and noise impacts, and impacts on resident and migratory animal life.

In a wind farm, individual turbines typically require 60 acres of land. Since the units themselves occupy only 5-10% of this acreage, dual use options, such as livestock grazing, are often feasible.

The noise generated by operating wind generation facilities is much different in both level and character from the noise generated by large power plants and other industrial facilities. It is generally considered to be low-level noise, resulting from both mechanical and aerodynamic components, and is more noticeable at lower wind speeds. Mechanical noise is caused by components moving out of alignment and as gears and bearings wear over time. Aerodynamic noise produces the “swishing” or “whooshing” sound caused by airflow over and past the turbine blades. It tends to increase with rotor speed and wind speed. The masking effect of wind noise renders mechanical noise at lower wind speeds as the chief culprit of noise pollution. Although no federal and few state noise standards exist, the U.S. Environmental Protection Agency has promulgated noise guidelines. Many local governments have enacted local noise ordinances that must be considered when siting wind facilities. Noise mitigation measures include requirements for noise setbacks of 400 to 1000 meters from the edge of the property line, installation of sound insulation and more. The ultimate cost impact of noise mitigation is a function of site specific features and circumstances.

6.4 Technology Status

The technology summary appears below, while cost data is presented in Chapter 1, Table 1-2, and Table 1-3.

Table 6-1
Technology Status – Wind

	Commercially Available Technology
Major Trends	Higher hub heights up to 135m plus for lower wind class areas Larger and lighter rotors and towers Longer, lower cost turbine blades Address wind turbine gearbox and blade reliability issues Drive to increase long-term reliability of wind turbines Design solutions to transportation challenges
Changes to Watch for	Continued renewal of production tax credit; extension of credit to investor owned utilities up to 2020 at least. Offshore wind projects in the US: Great Lakes, Northeast Atlantic and Northwest Pacific coasts Expanded use of type IV (direct drive) generators Alternate tower designs to facilitate higher hub heights and mitigate transportation challenges Improved O&M methods and condition monitoring Increased focus on testing and validation of wind turbine major components
Resource Requirements that Impact Technology	Wind resources Available land for project sites Transmission capacity Zoning and permitting issues Wind energy on-site storage
Key Issues	Complexity of full-span pitch controls increases maintenance. Availability and capacity factors of wind power plants. Curtailment of wind plants due to transmission congestion. Long interconnection queues in best wind regions. Integration of large-scale wind energy; managing wind energy variability. Lack of unified codes and standards for the design of wind turbine foundations. Financing constraints (from late 2008 to early 2012). Role of energy storage integrated with wind energy projects. High capital cost of wind projects; not competitive without incentives. Offshore wind energy project design codes and standards (in the U.S.). Wind turbine foundation design standards (in the U.S.).
Key Business and Market Indicators	Incentives to cover upfront cost of projects. Grid interconnection queue reform activity. Utility ownership of wind projects is expanding (although IPP ownership remains dominant). RPS– state requirements, potential U.S. national standard.

7
SOLAR

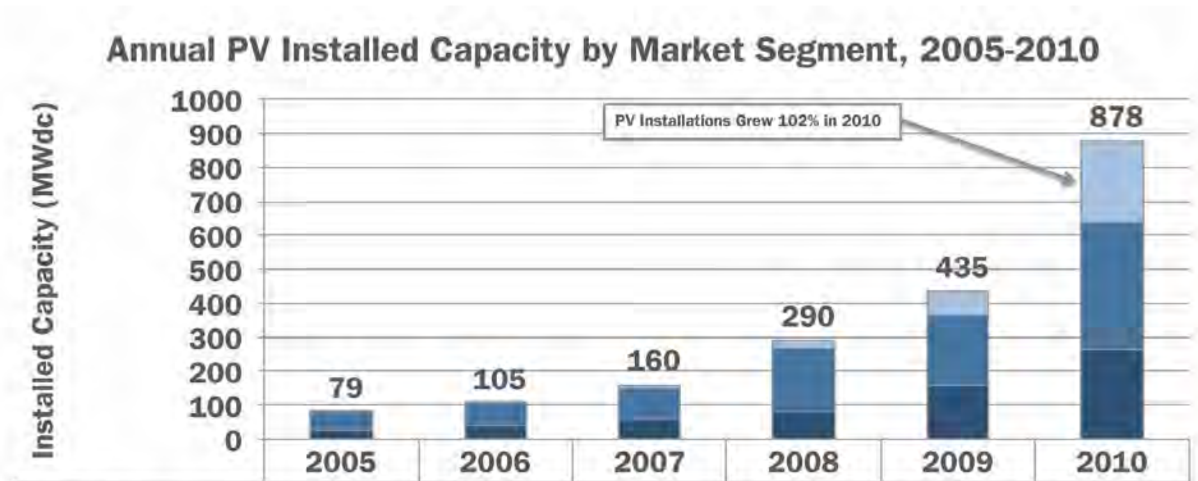
7.1 Description

Anticipation of CO_2 policies, existing and potential renewable portfolio standards (RPS), and rapid technology development have prompted significant investment in solar technologies. Consequently, solar electricity generation represents a small but growing share of the world's energy supply. Solar power technologies can be divided into two categories: concentrating solar thermal (CST) – also referred to as concentrating solar power (CSP) – and photovoltaics (PV). CST technologies use mirrors to concentrate sunlight onto a line focus or central point in order to heat up a working medium, which ultimately produces electricity in a steam cycle. PV technologies directly convert sunlight into electricity, and may or may not include concentration.

In 2010, the U.S. added 878 MW of grid-connected PV (including both utility scale and rooftop installations) and 78 MW of CST, bringing cumulative installed capacity to 2,100 MW of PV and 507 MW of CST. [14] Though 2010 was a banner year, the future of the U.S. solar energy industry remains sensitive to government subsidies. The U.S. Treasury Department Section 1603 cash grant program is currently slated to expire at the end of 2011, and the future of the federal loan guarantee funds is unclear.

7.1.1 Solar Photovoltaic (PV)

In 2010, globally installed PV grew 130% to 17 GW and the U.S. market grew by 102% to 2.1 GW. At the same time, the U.S. saw its global market share decline from 6.5% in 2009 to 5% of new global capacity in 2010, Significantly, utility capacity (PV projects over 100 kW on the utility side of the meter with a utility or wholesale power purchaser) expanded in 2010 (see Figure 7-1) from 16% (70 MW) in 2009 to 28% (242 MW) in 2010. [14]



	2005	2006	2007	2008	2009	2010
Total	79	105	160	290	435	878
Utility	1	0	9	22	70	242
Non-Residential	51	67	93	190	208	372
Residential	27	38	58	77	157	264

Figure 7-1
Annual Installed PV Capacity in U.S. by Market Segment, 2005-2010 [14]

Relatively small-scale distributed generation in residential- and commercial-scale applications still dominate current deployments. New PV technologies and policies that encourage investment (through rebates, subsidies, feed-in tariffs and tax incentives) are making small-scale on-site generation increasingly attractive. Although large-scale PV facilities remain comparatively more expensive than other bulk-power options, there has been a growing trend in some markets toward new PV projects being developed in the 10 MW and larger capacity range.

PV solar cells are made of layers of semiconducting materials in which absorbed sunlight creates electron flow through the cell to produce electricity. PV modules can be mounted at a fixed angle facing the sun or mounted on a tracking device. Additional system components include support structures, inverters, wiring and transmission, and sufficient land to capture adequate levels of sunlight.

The majority of currently produced cells use wafer-based crystalline silicon technology, which is fairly well understood. Sensitivity to silicon costs and the sophistication of cell fabrication are key factors with this technology. However, technology is moving toward thin films that use only 1-5% of the material compared to the crystalline silicon modules. Currently available commercial modules for first generation wafer-based crystalline silicon technology have efficiencies in the range of 15-20%. Today's second generation thin film technologies have lower efficiencies, predominantly under 10%.

Today's prevailing cell technologies are based on a single junction, or interface, which can use only a small portion of the sun's energy spectrum. However, emerging multi-junction or tandem cells will allow multiple layers to use progressive parts of this spectrum, resulting in higher efficiencies. In this case, solar cells of different band-gaps are stacked on top of each other and each layer absorbs the light wavelength that it is designed to most efficiently convert. Multi-junction cells have shown efficiencies above 40%. For now, the high cost associated with their semi-conductor material renders this technology too expensive except in concentrator systems.

The electricity produced by a PV cell is direct current (DC) and an inverter is used to convert the electricity to alternating current (AC). The efficiency of a solar cell is defined as the amount of absorbed light that is converted to electrical energy. The actual amount of power produced will depend on multiple factors including the sunlight's intensity (W/m^2), the operating temperature, wiring losses, soiling, panel mismatches and DC to AC conversion efficiency. Total PV system losses are typically in the range of 20-25%. Reducing these losses is a research focus of the solar industry at the respective component level.

The cost of the PV module is about half to two thirds of the total system cost, thus modules are a large cost driver and are expected to decline with improvements in PV design and manufacturing processes. Additionally, the costs associated with the inverter as well as the design, engineering, and installation costs for the overall PV system are high. However, for large-scale systems inverter costs are expected to decrease. The design and installation costs of inverters are expected to decrease as the number of installations increase.

7.1.2 Concentrating Solar Thermal (CST)

Concentrating solar thermal technologies use sunlight to heat a medium and then use the medium to drive a power generation system. Using mirrors, the sun's energy can be concentrated up to 1,000 times and focused onto a receiver where a gas or liquid inside the receiver is heated to high temperatures and transfers the heat to a power generation system. In general, concentrating solar power plants are better suited to large-scale applications than photovoltaic systems. Solar thermal technologies have also been used worldwide for residential and commercial heating.

There are four common types of solar thermal power systems: parabolic trough, central receiver or power tower, compact linear Fresnel reflector (CLFR) and dish/engine. Because all of these technologies involve a heat-driven engine, most can be readily hybridized with fossil fuel and in some cases are adapted to use thermal energy storage. The primary advantage of hybridization and thermal energy storage is that the technologies can provide firm, dispatchable power during periods when solar energy is not sufficient. Thus, hybridization and thermal energy storage can enhance the economic value of the electricity produced. However, both of these approaches are still in the demonstration phases.

Each of the four solar thermal technologies is at a different stage of development. Currently, parabolic trough is the only technology to have achieved commercial status with over 725 MW installed worldwide. Power towers and CLFR have been demonstrated at pilot scale and dish/engines at the kilowatt scale. These technologies are expected to be demonstrated in large scale projects over the next few years.

Parabolic trough systems use banks of trough-shaped mirrors with a parabolic cross-section to focus sunlight onto highly absorbing/low emitting receiver tubes that contain a heat-transfer fluid (HTF). This fluid, typically a synthetic oil, is heated and pumped through a series of heat exchangers to produce steam that powers a conventional Rankine cycle.

Power towers, also referred to as central receiver systems, use a field array of large mirrors called "heliostats" that track the sun and focus its light onto a central receiver mounted on top of a tower. Over 3000 MW of new U.S. and EU power tower projects are being proposed for construction over the next two to seven years.

Dish/engine systems use an array of mirrors made from glass facets to form a parabolic dish that focuses solar energy onto a receiver located at the focal point of the dish. An HTF, typically helium or hydrogen, is heated in the receiver tube and used to generate electricity in a small engine attached directly to the receiver. Current designs employ a Stirling engine, but future designs could use Brayton-cycle (turbine) engines or dense arrays of high-efficiency photovoltaic cells.

CLFR technology is conceptually similar to the parabolic trough, except instead of using curved mirrors it uses a field of nearly flat mirrors individually tilted and turned on their axes to reflect sunlight to the receiver. While a conventional parabolic trough solar thermal system has one curved reflector for each receiver line, the CLFR system typically has 10. Each individual mirrored reflector has the option of directing reflected solar radiation to at least two different receivers. This minimizes shading losses, allows arrays to be much more densely packed, and permits the receiver tubes to be lower than would otherwise be possible. Within the receiver, pressurized water is converted to saturated conditions, and the steam from this process drives conventional Rankine cycle steam turbines and generators. CLFR technology is designed to reduce capital costs compared to parabolic trough and central receiver systems. The unresolved question is whether the capital cost is sufficiently low to compensate for the lesser performance of CLFR systems.

Table 7-1
Concentrating Solar Thermal (CST) Technology Comparison

Concentrating Technology	Technology Comparison
Parabolic Trough	• most mature technology • intermediate operating temperature • currently lowest cost • high water requirement (for wet-cooled plants only)
Power Tower	• highest land requirement • high water requirement (for wet-cooled plants only) • high operating temperature
Dish/Engine	• highest operating temperature • highest efficiency • minimal water required • modular • currently no storage options
Compact Linear Fresnel Reflector (CLFR)	• lowest operating temperature • high water requirement (for wet-cooled plants only) • smallest footprint • currently no storage options • potentially lowest capital cost

Long-term cost projections for trough technology are higher than those for power towers and dish/engine systems due in large part to the HTF, which results in lower temperatures and efficiency. However, with 15 to 20 years of operating experience, continued technology improvements, and O&M cost reductions, troughs could be the least expensive, most reliable solar thermal electric technology for near-term deployment. Research is also underway to demonstrate trough systems with higher temperature working fluids that could enable higher efficiencies.

7.2 Solar Resources

The solar energy resource at a given location is characterized by the solar radiation per unit area (or "insolation") expressed in units of kilowatt-hours or megajoules per square meter per year ($kWh/m^2/yr$ or $MJ/m^2/yr$). The insolation reaching the Earth's surface varies with latitude, time of day, and season, as well as with local weather and atmospheric conditions arising from natural particulates or air pollution. Areas of higher annual average annual insolation can will produce more energy from a given system. For example, a typical U.S. household using an average of 920 kWh per month would need an approximately 7 kW DC solar system to offset its annual electricity usage in Albuquerque, NM, whereas it would take a 43% larger system (almost 10 kW DC) in Knoxville, TN to generate the same amount of energy. [15]

Lower latitude regions in the southern United States, and especially those with dry climates in the Southwest, typically exhibit the highest average insolation in the U.S. Figure 7-2 and figure 7-3 present an assessment of PV and CST solar resources from the National Renewable Energy Laboratory (NREL).

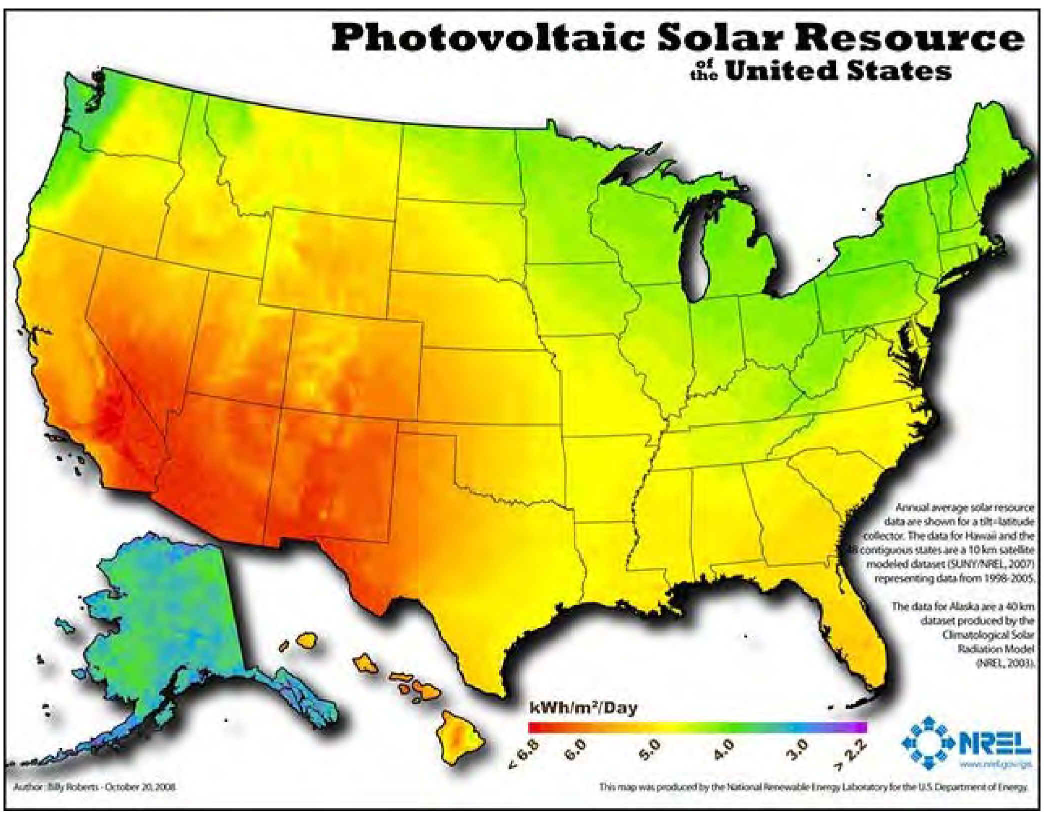


Figure 7-2
Diffuse Normal Solar Resource Map of the United States (for Photovoltaic) [16]

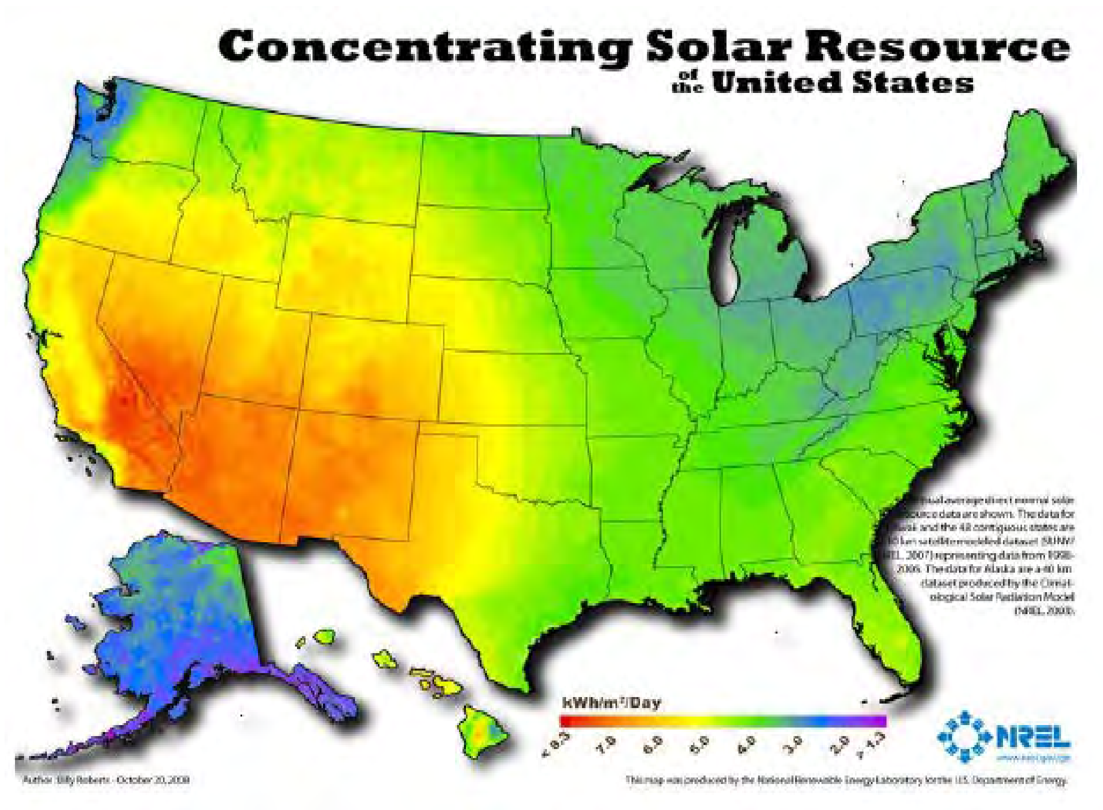


Figure 7-3
Direct Normal Radiation Resource Map of the United States [16]

Table 7-2 presents a summary of power production and capacity factor estimates by PV technology and configuration for four U.S. locations. Differences in capacity factor translate directly into the levelized cost of electricity. That is, higher capacity factors yield lower cost electricity.

Table 7-2
Power Production Estimates for 10 MW Solar PV Plants [17]

Technology	Location	First Year MWh	AC Capacity Factor
Fixed a-Si	Las Vegas, NV	19,760	22.6%
	Alamosa, CO	16,770	19.1%
	Jacksonville, FL	14,910	17.0%
	Columbus, OH	12,810	14.6%
Fixed CdTe	Las Vegas, NV	19,450	22.2%
	Alamosa, CO	18,150	20.7%
	Jacksonville, FL	14,780	16.9%
	Columbus, OH	12,590	14.4%
Single Axis Tracking Crystalline	Las Vegas, NV	21,940	25.0%
	Alamosa, CO	22,200	25.3%
	Jacksonville, FL	16,150	18.4%
	Columbus, OH	13,820	15.8%
Tilted Single Axis Tracking Crystalline	Las Vegas, NV	23,590	26.9%
	Alamosa, CO	23,470	26.8%
	Jacksonville, FL	17,160	19.6%
	Columbus, OH	14,830	16.9%
Fixed Crystalline	Las Vegas, NV	19,640	22.4%
	Alamosa, CO	18,490	21.1%
	Jacksonville, FL	14,830	16.9%
	Columbus, OH	12,600	14.4%
Concentrating Solar PV	Las Vegas, NV	24,294	27.7%
	Alamosa, CO	24,416	27.9%

a-Si Amorphous silicon
CdTe Cadmium telluride

7.3 Environmental Considerations

Solar generation technologies – especially CST – are accompanied by environmental considerations which are not trivial. CST and PV both require considerable land, and CST consumes water on par with thermal power plants when utilizing wet cooling. Solar power generation does not produce carbon dioxide unless it uses an auxiliary natural gas boiler.

Land footprints are in the range of 8 to 10 acres per MW of generating capacity. Drivers of land area requirements are quality of the solar resource, presence of a tracking capability, efficiency of solar to energy conversion, and, in the case of CST with storage, the number of hours of storage capacity (10 acres per MW corresponds to about 9 hours of thermal energy storage in good solar-resource locales). Parabolic trough and central receiver plants with thermal energy storage systems have oversized collector fields (extra mirrors) to capture energy for the storage system during the peak hours of the day. The generating units will typically not be designed to use the entire peak thermal output of the collector field.

Except for Dish/Stirling engines, water requirements of solar thermal generating plants are similar to those of other thermal power plants of equal nameplate capacity using wet cooling towers. In all cases, a minor amount of water is consumed for periodic mirror cleaning.

7.4 Technology Status

Because there have been only a limited number of utility scale CST or PV plants constructed in the U.S., there is significant uncertainty in the estimated costs. In addition, solar technology suppliers/developers are reluctant to supply cost estimates for their associated plant designs due to the competitive nature of the current solar industry.

Table 7-3
Technology Status – Solar Photovoltaic (PV)

	PV Technologies
Major Trends	Feed-in tariff incentivizing small to medium scale (< 10 MW) installation Increase in state renewable portfolio standards (RPS) Declining capital cost Moving toward higher market penetration of thin films Residential applications integrated with utilities due to incentives Building integrated installations such as roof shingles Central utility applications greater than 2 MW
Changes to Watch for	Ongoing growth in thin film and concentrating technologies Decline in cost of inverters Utility PV systems Nanotechnologies, organics, multi-junctions and band-gap engineering.
Efficiency (solar to electric)	10 - 20%
Market Restructuring & Deregulation	Power Purchase Agreements (PPA) with utilities as they strive to meet RPS
Key Issues	Established goal: achieving 15% efficiency at cost of $100/m^2

Table 7-4
Technology Status – Concentrating Solar Thermal (CST)

	Parabolic Trough	Power Tower	Dish/Engine	Linear Fresnel Reflecting
Major Trends	Hybrid applications Thermal storage Larger plant sizes Higher temperature working fluids	Hybrid applications Potentially large projects in the U.S. and Europe. Thermal storage to allow dispatchable solar power	Large demonstration projects with CA utilities. New materials and techniques to reduce manufacturing and O&M costs	Early demonstration projects. Hybrid applications
Changes to Watch for	Direct steam generation. New materials and techniques to reduce manufacturing and O&M costs. Lower-cost mirror support structures. Reflective films in place of mirrors	Grid connected utility applications. Advances in thermal storage. Higher operating temperatures	Grid connected utility applications	Higher temperature steam generation. Advanced steam storage technology
Efficiency (solar to electric)	13.5%	8-22%	16-30%	N/A
Resource Requirements that Impact Technology	Magnitude of direct normal solar radiation. Water availability, especially in arid climates.		Magnitude of direct normal solar radiation.	Same as parabolic trough
Key Issues	Steam or gas flow control Cost reduction potential of reflective film collectors Freeze protection of molten-salt HTF in collector field Operation of thermal storage tanks	Scale up High temperature operation Cost reduction	Scaling up manufacturing Engine availability O&M costs Cycling impacts	Low temperature thermal energy storage Sufficient cost reduction to offset lower efficiency
Key Market Indicators	Increase in state-level RPS. Commercial applications.			

8

LCOE IMPLICATIONS OF CO_2 EMISSIONS COSTS

Potential future policies limiting U.S. CO_2 emissions would create a cost for each metric ton of CO_2 emitted. Thus the levelized costs of electricity associated with different forms of generation will increase according to the emissions intensity of each generation technology. By combining these additional emissions-related costs with overall levelized electricity cost estimates presented in this report, sensitivity curves were developed showing levelized costs of electricity (including assumed transport and storage cost of $10/metric ton for captured CO_2) as a function of potential CO_2 emissions allowance costs. When shown together, the relative position of these sensitivity curves provides a perspective on the strategic importance of different technologies under different levels of CO_2 emissions allowance costs.

As discussed in this report, accurate comparison of the capital costs and levelized electricity costs for different generation technologies requires care to ensure that all values are computed on a consistent basis. This section provides a set of presentation slides entitled “Generation Options under a Carbon-Constrained Future” which provide explanations of key concepts underlying cost estimates, as well as the sensitivity curves described above. The LCOE values presented are the same as those presented at the end of Chapter 1 in Table 1-2 and Table 1-3. These curves are estimated for two timeframes, 2015 and 2025, to illustrate the potential impact of successful research, development, and demonstrations (RD&D) on the costs of technologies.

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Generation Technology Options in a Carbon-Constrained World

Prepared by the
Energy Technology Assessment Center

(Reference: EPRI Report 1022782)

Levelized Cost of Electricity Analysis

Objectives

- Provide a useful generic basis for comparison of technologies for base load generation.
- Provide **strategic** comparisons of technologies over plant lifetimes.
- Evaluate sensitivities of levelized cost of electricity (LCOEs) to potential CO_2 costs and other parameters.

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Levelized Cost of Electricity Analysis

Analytical Basis

- Utilize EPRI capital cost data and methodologies to calculate levelized costs of electricity (LCOEs) in constant 2010 $.
  - Incorporate key assumptions needed for calculations – capital cost, fuel cost, fixed and variable O&M, plant life, fuel type and energy content, cost of money.
  - No production or investment tax credits assumed for any technologies.
- Assume that current technology parameters and costs are representative of 2011–2015.

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Levelized Cost of Electricity Analysis

Analytical Basis

- The weighted average cost of capital (WACC) on a real dollar basis, after tax, is 5.0%, and technology-specific plant lifetimes and accelerated depreciation schedules are used.
- Mercury, SO_x/H_2S and NO_x removal are included in PC and IGCC Technologies. NO_x removal is included in NGCC Technology.

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Levelized Cost of Electricity Analysis

Capital Cost Estimating Approach

- Costs are to be reported in reference year (December 2010) dollars:
  – No cost escalation to startup date included
- Plant site is assumed to be clear and level
- Cost estimate assumes mature technology:
  – Plant is assumed to operate as designed (no allowance for field modifications)
  – Extra costs for 1st-of-a-kind demonstration not included

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Levelized Cost of Electricity Analysis

Cost Basis

- Total Plant Cost (TPC):
  - Sometimes referred to as Engineering, Procurement, and Construction Cost (EPC), or Overnight Capital Cost
  - All process and support facilities; fuel handling and storage; water intake structure and wastewater treatment; offices, maintenance shops, and warehouses; step-up transformer and transmission tie-in
- Owner's Costs:
  - Pre-production costs, working capital, land, license fees, interest during construction
- Project-specific Costs:
  - Project development, utility interconnections, legal/financial consulting, owner's project management

- **Total Capital Requirement (TCR), or "All-In" Costs**
  - **TCR = TPC + Owner's Costs + Project Specific Costs**

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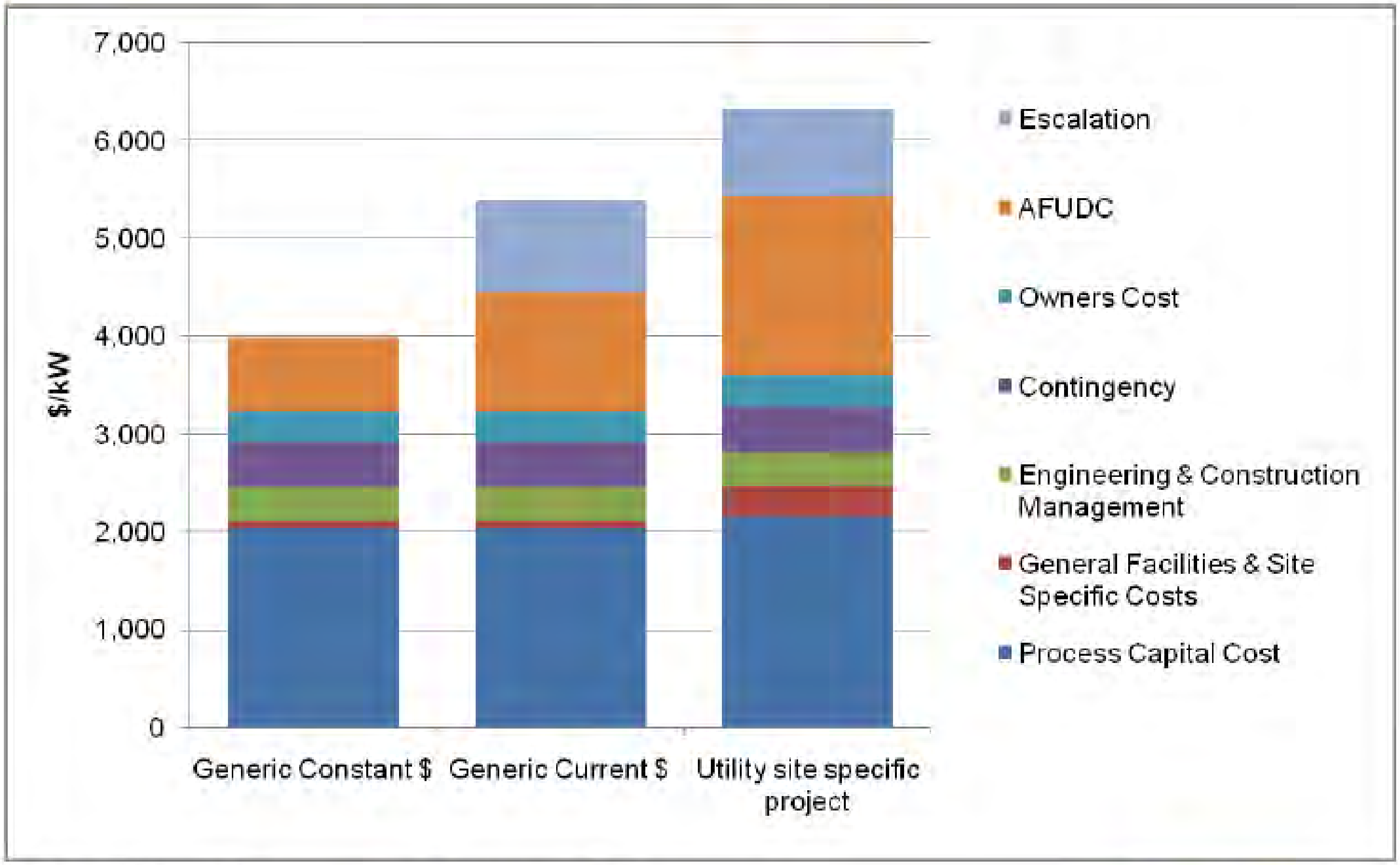
Levelized Cost of Electricity Analysis

Capital Cost Estimate Summary

- Total Capital Requirement (TCR) can be significantly higher than Total Plant Cost (TPC):
  - Typical EPRI Owner's Costs add about 3–11% to TPC
  - Interest during construction adds another 4–36% to TPC
- The adder for project-specific costs varies widely:
  - Depends on project and site-specific requirements
  - Roughly equivalent to 10–15% of TPC
- When comparing capital cost estimates:
  - It is important to know if values are in constant year dollars vs. future year dollars
  - It is important to know which components of cost are included/excluded

Magnitude of Cost Estimates* can be Very Different Site Specific vs. Generic Constant $, Current $



* **Data shown for illustrative purposes only**

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Levelized Cost of Electricity Analysis

Technology Assumptions

- Near Term – 2010 to 2015
  - Modest extrapolation of today's technology.
  - Based on foreseeable technology development.
- Longer Term – 2020 to 2025
  - Assume that established R&D objectives are achieved, and technology development is successful.
  - Estimated reductions in costs are based on assessment of potential technology improvements.

Levelized Cost of Electricity Analysis

- Individual technology slides
  - Range of LCOEs presented as shaded region
  - Solid line represents median
  - Solid line and dashed line represent upper and lower bounds of fuel price, respectively

- Technology summary slides
  - NGCC and biomass LCOE is presented as shaded region, principally reflecting the range of fuel prices
  - Solar is not included due to high LCOE beyond scale of chart

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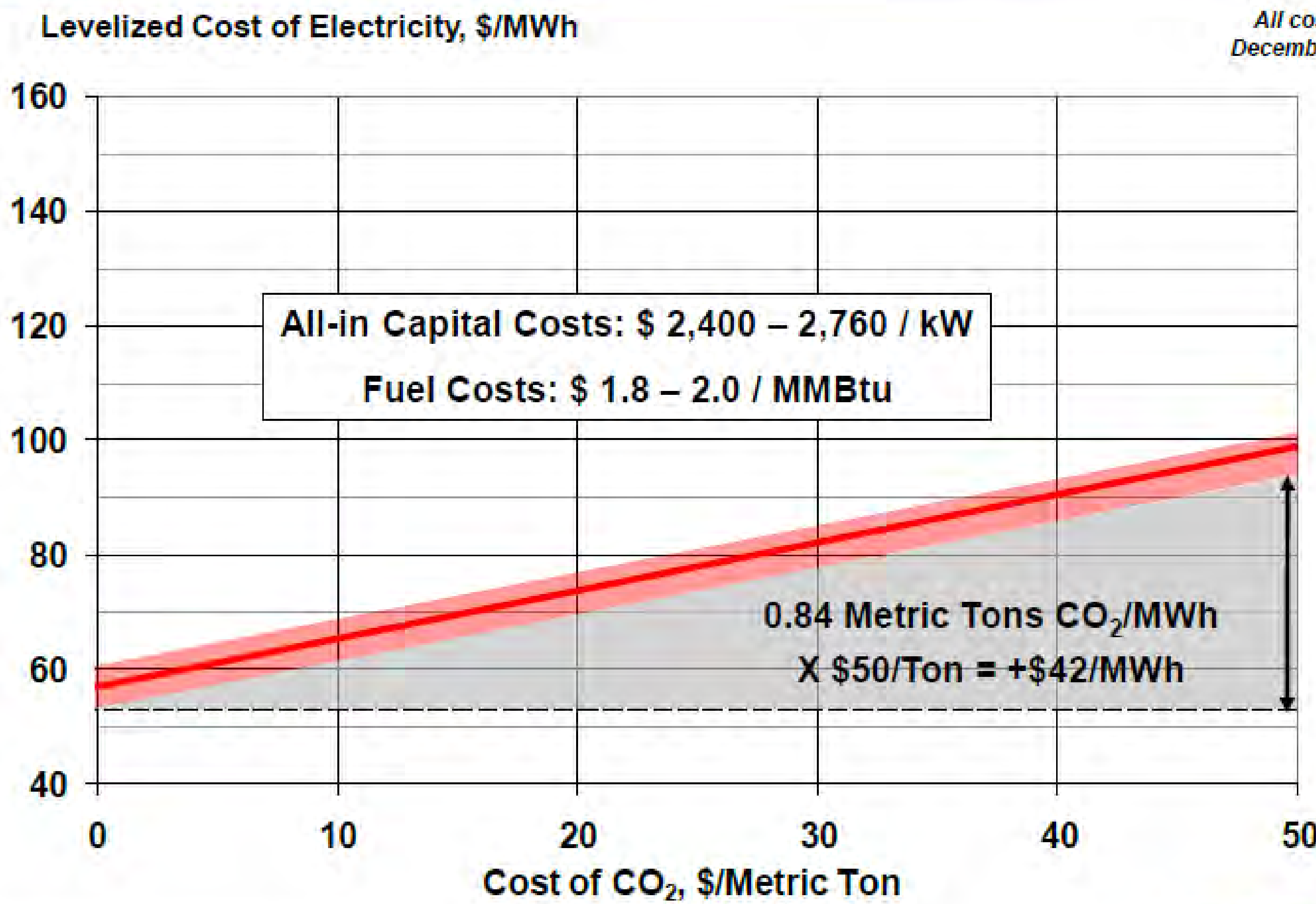
Near-Term: 2015

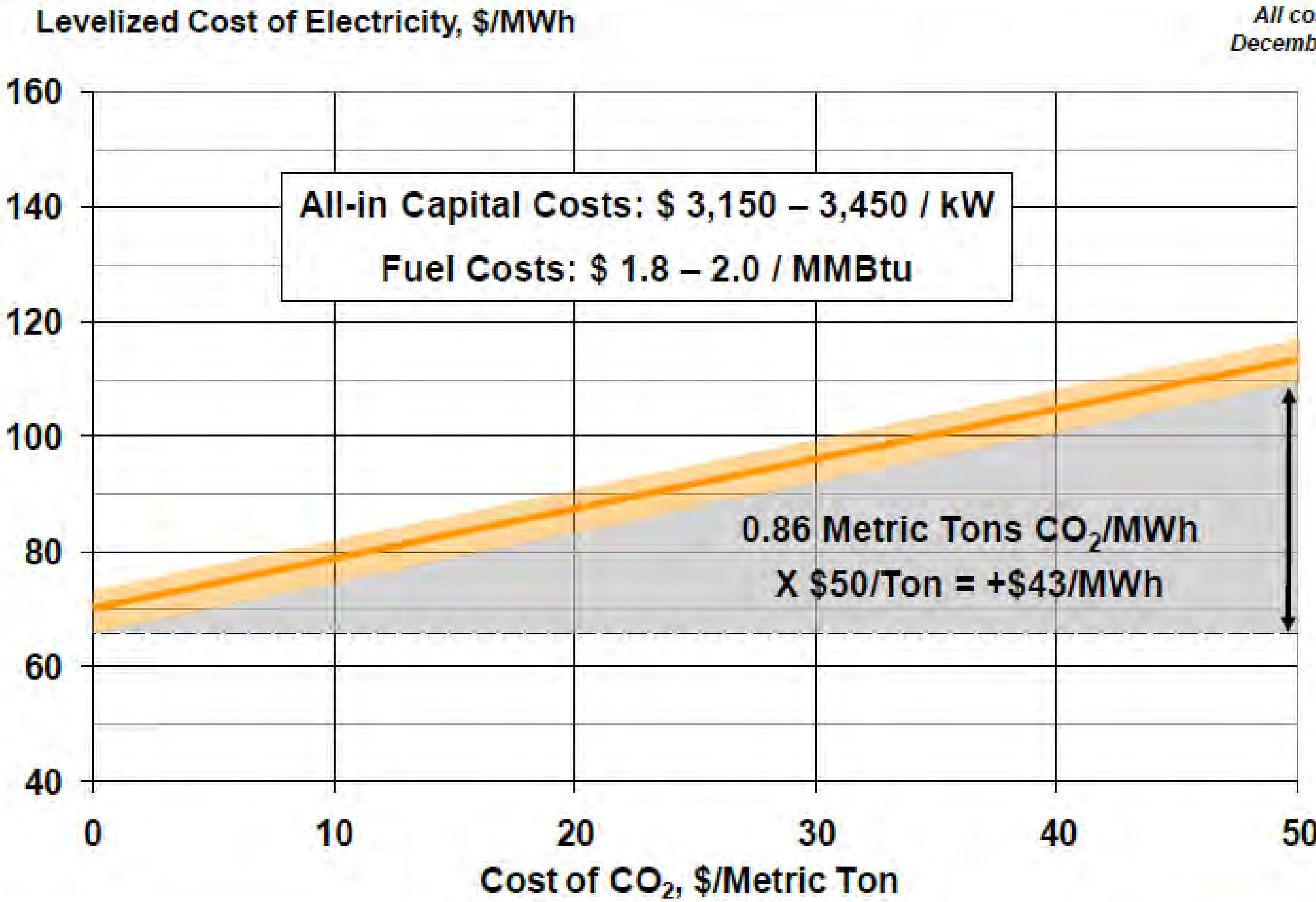
Pulverized Coal Combustion – 2015

All costs are in December 2010 $



Integrated Gasification Combined Cycle (IGCC) Coal Combustion – 2015

All costs are in December 2010 $



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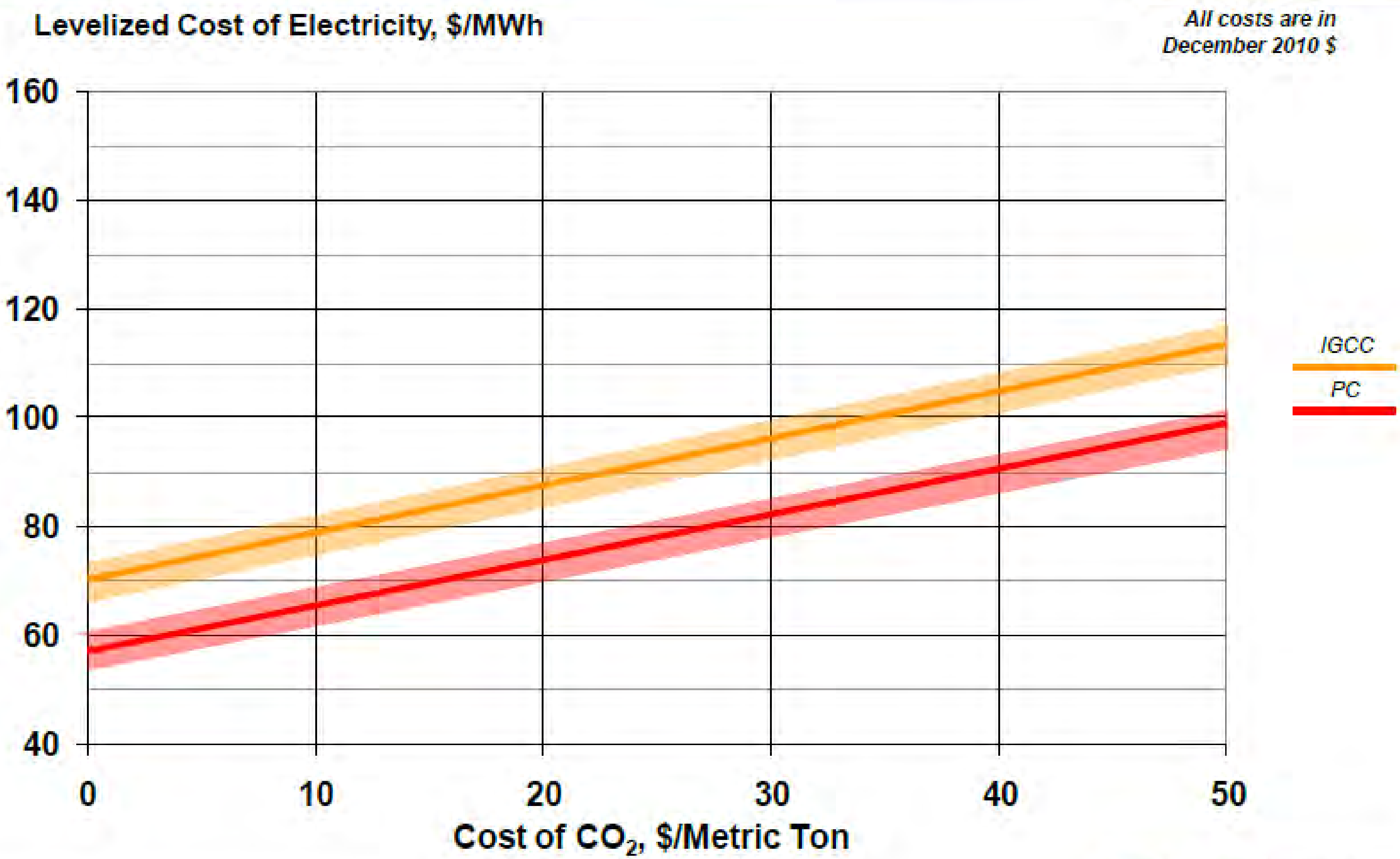
Coal Combustion and Gasification Comparison – 2015

All costs are in December 2010 $



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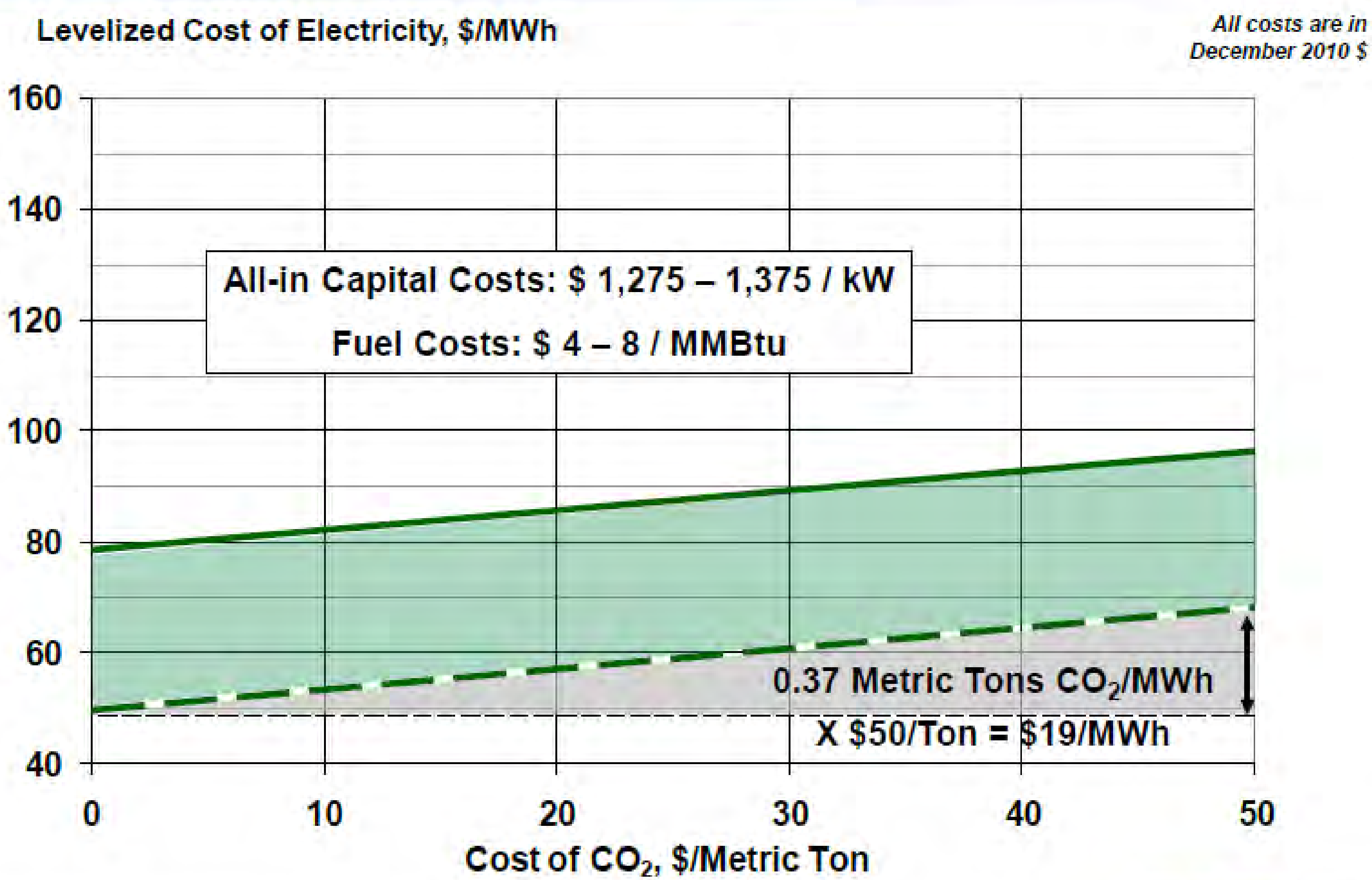
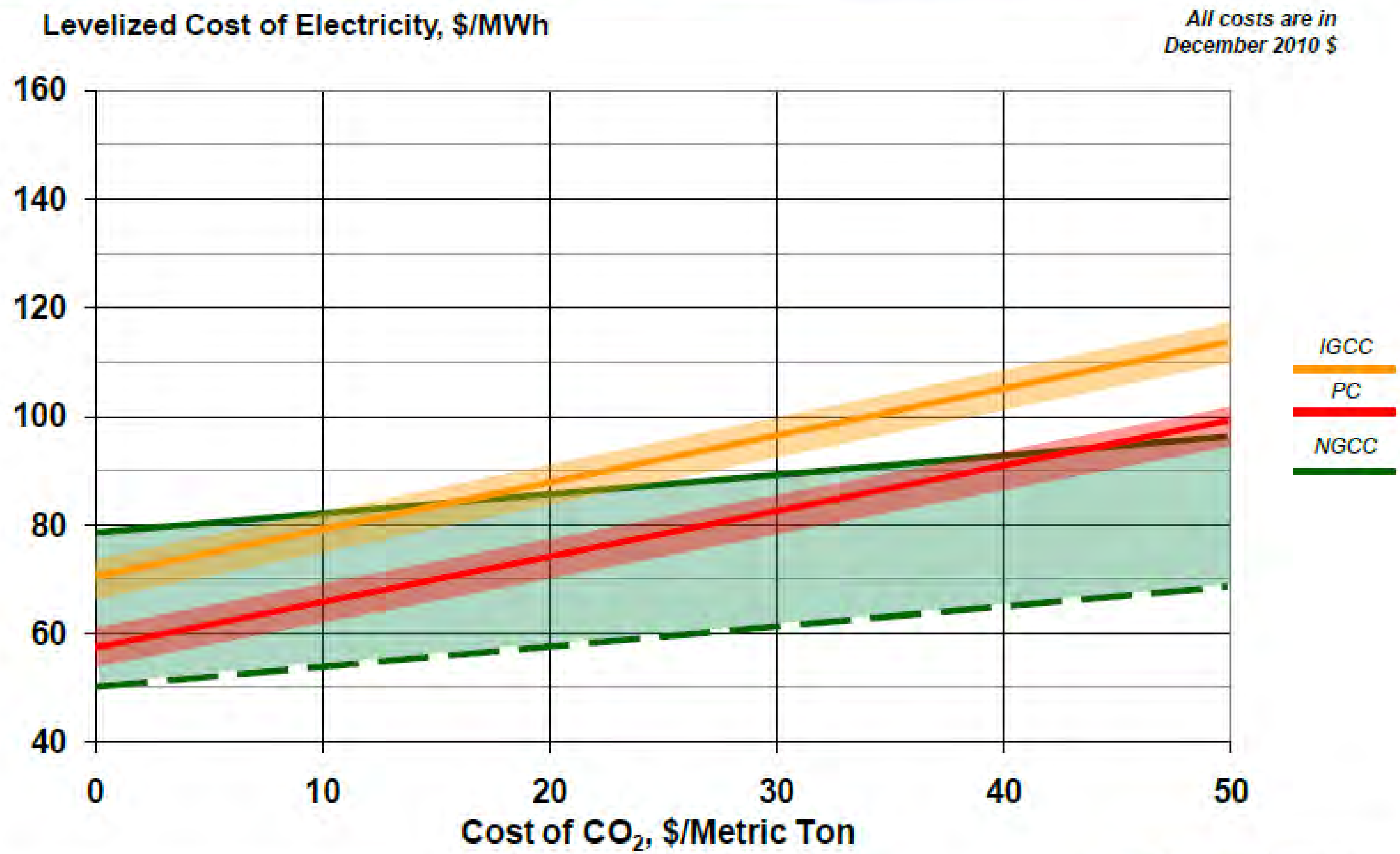
Natural Gas Combined Cycle (NGCC) Fuel Cost Sensitivity Comparison – 2015



PC, IGCC, NGCC Comparison – 2015



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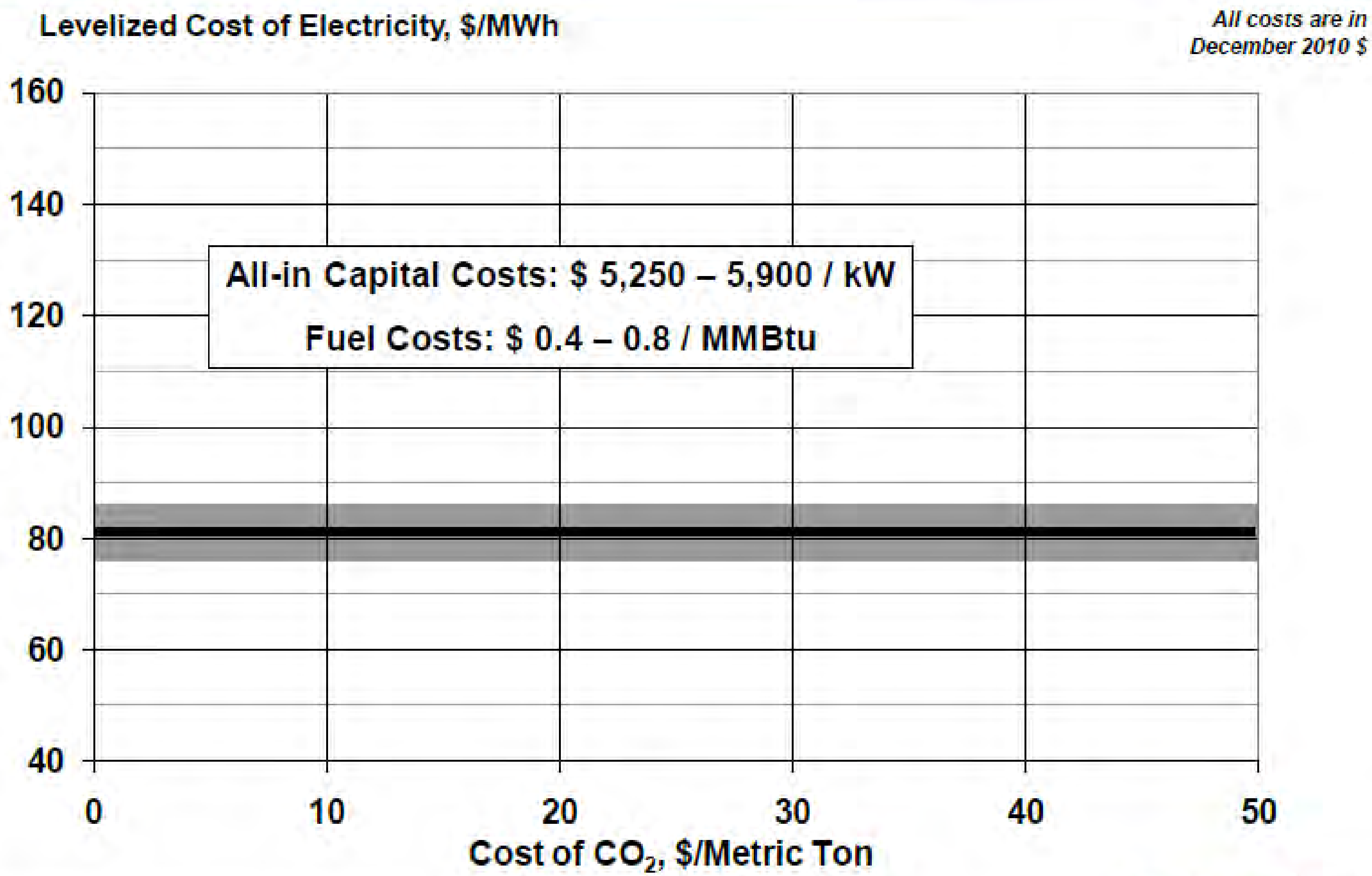
Nuclear – 2015



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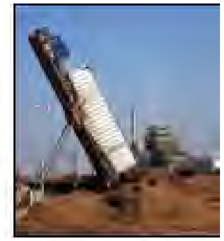
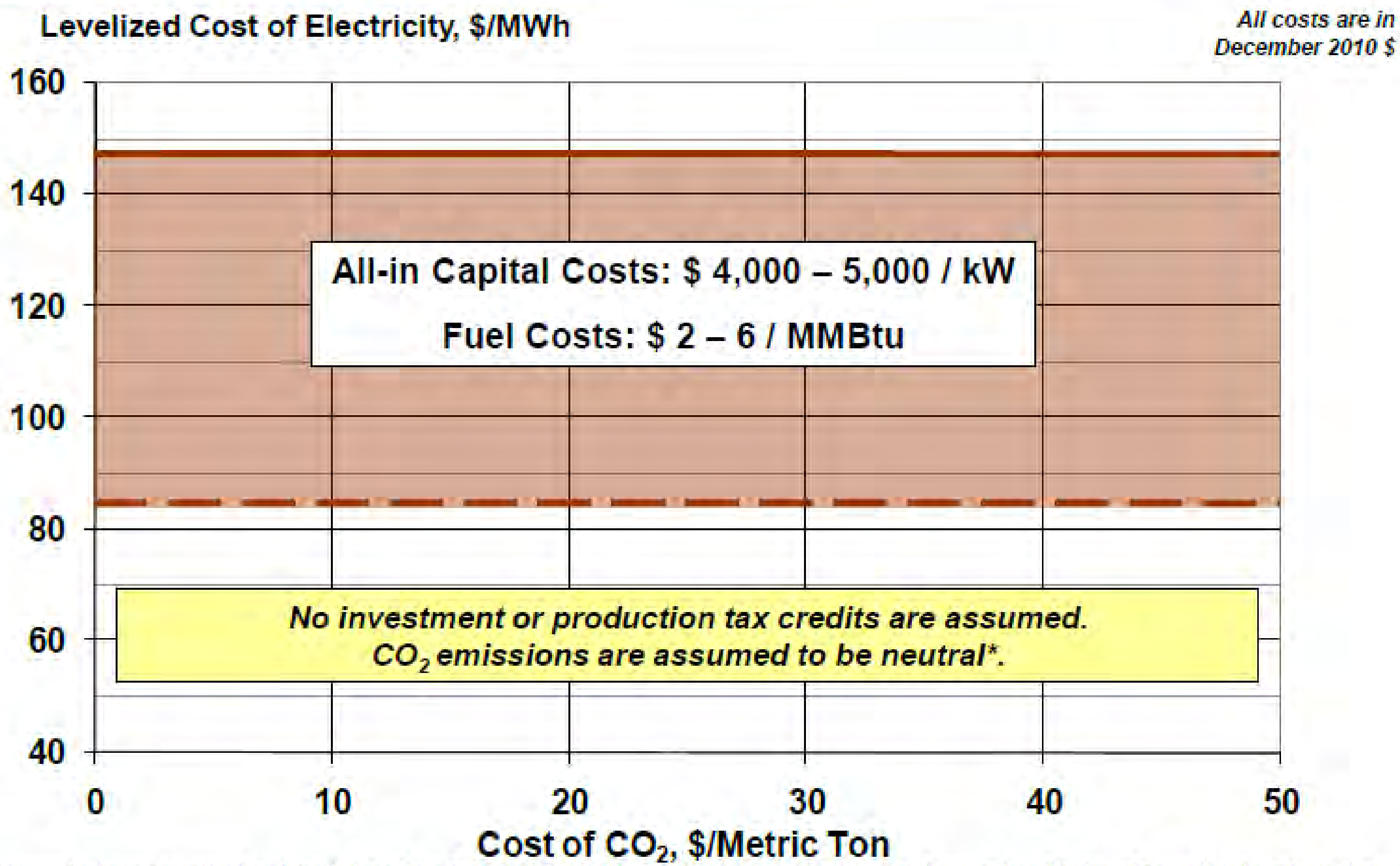
Biomass – 2015

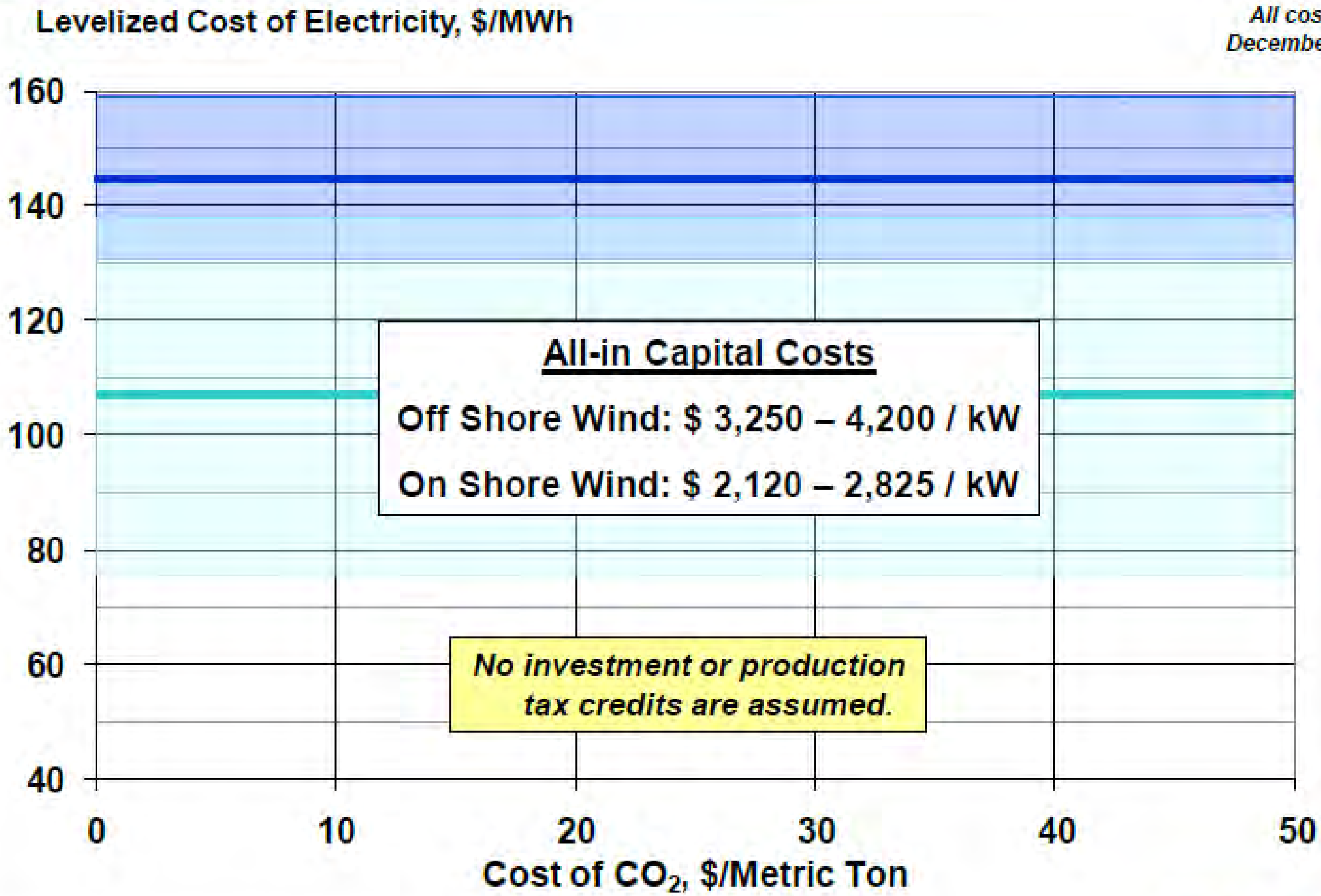




*Biomass emissions can vary significantly based on fuel source and life-cycle emission assumptions. Conventionally, the release of carbon from biogenic sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net CO_2 emissions over some period of time.

Wind – 2015

All costs are in December 2010 $



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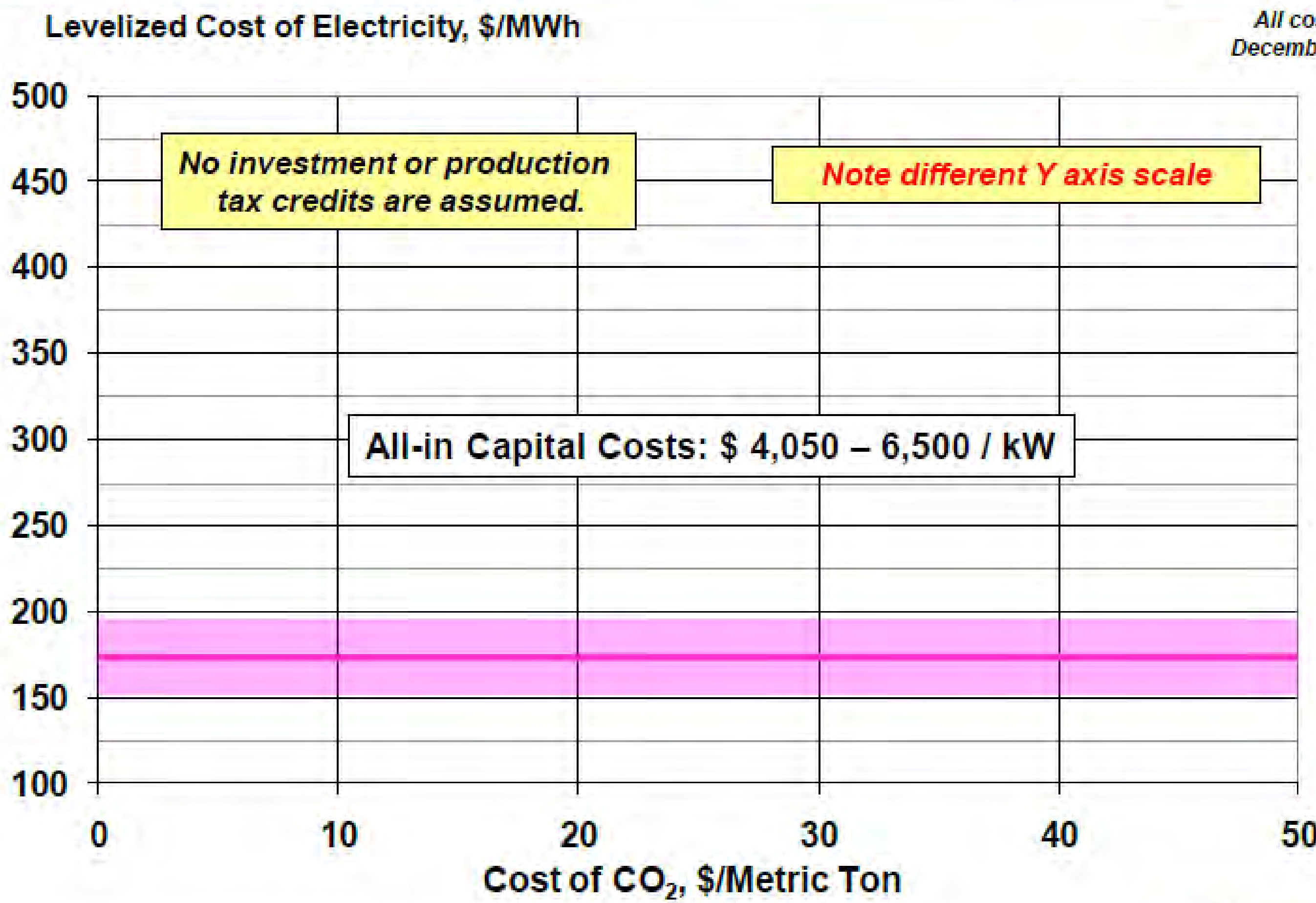
Concentrating Solar Thermal – 2015

All costs are in December 2010 $



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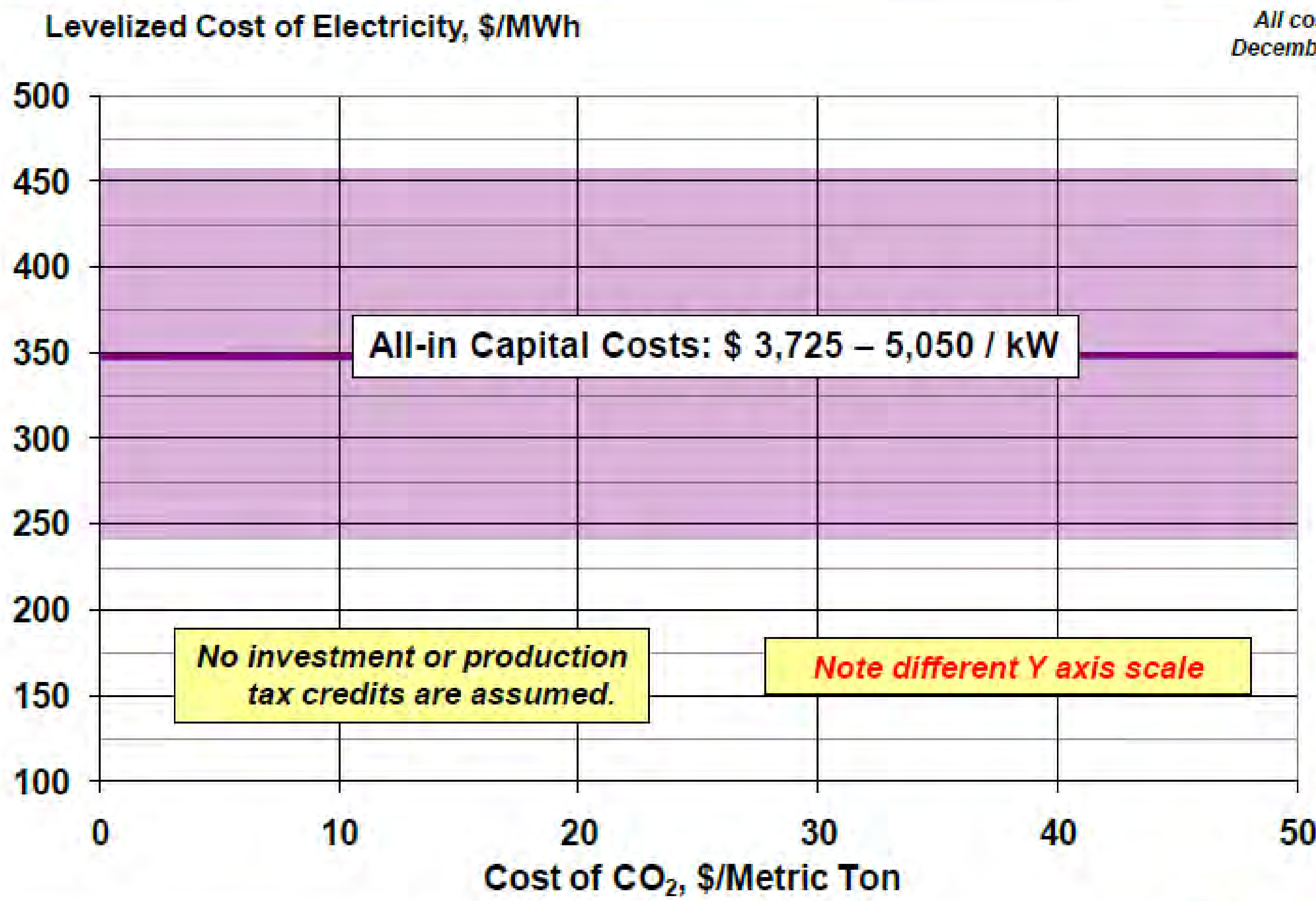
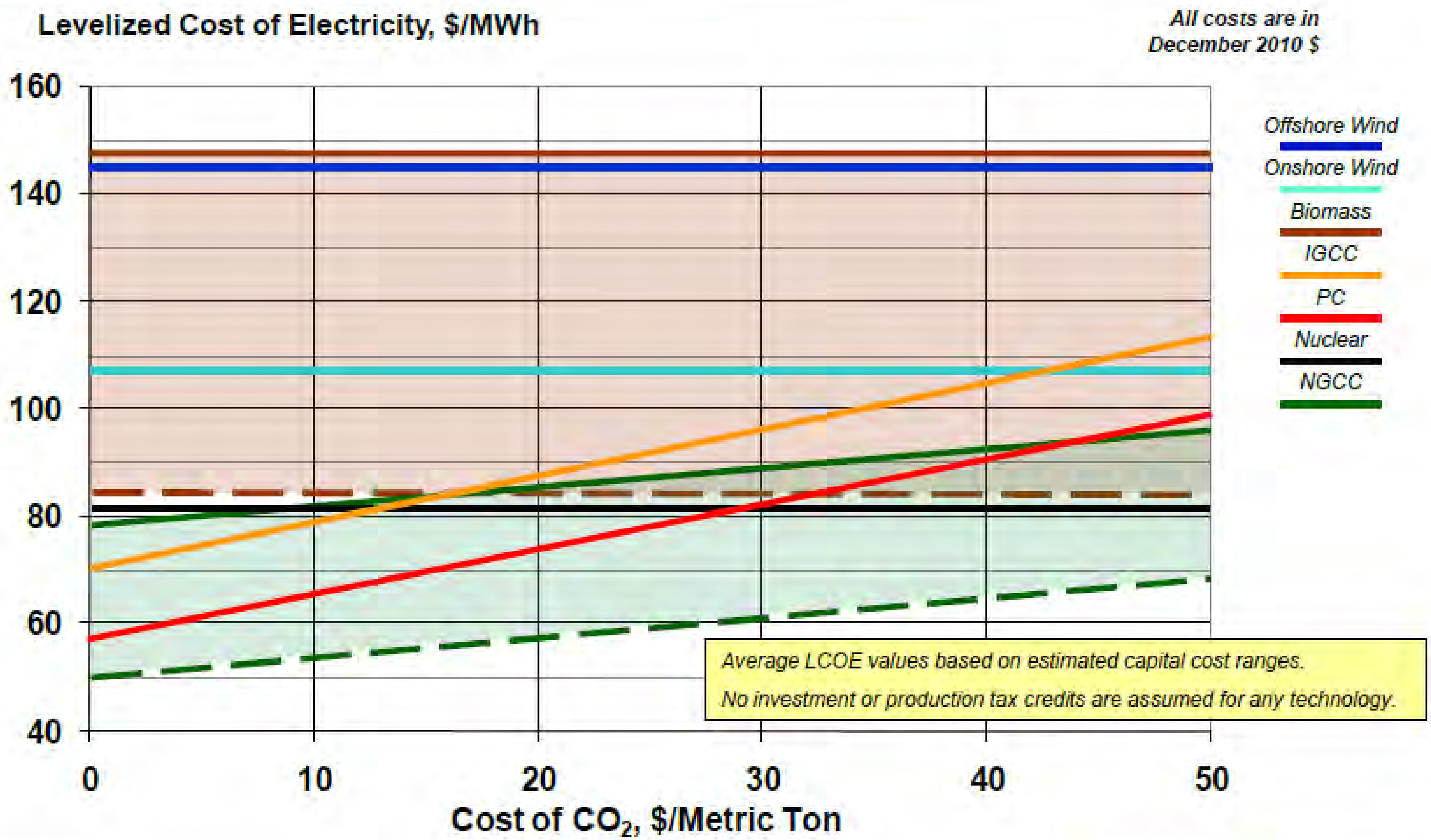
Solar Photovoltaic – 2015

All costs are in December 2010 $



Comparative Levelized Costs of Electricity – 2015



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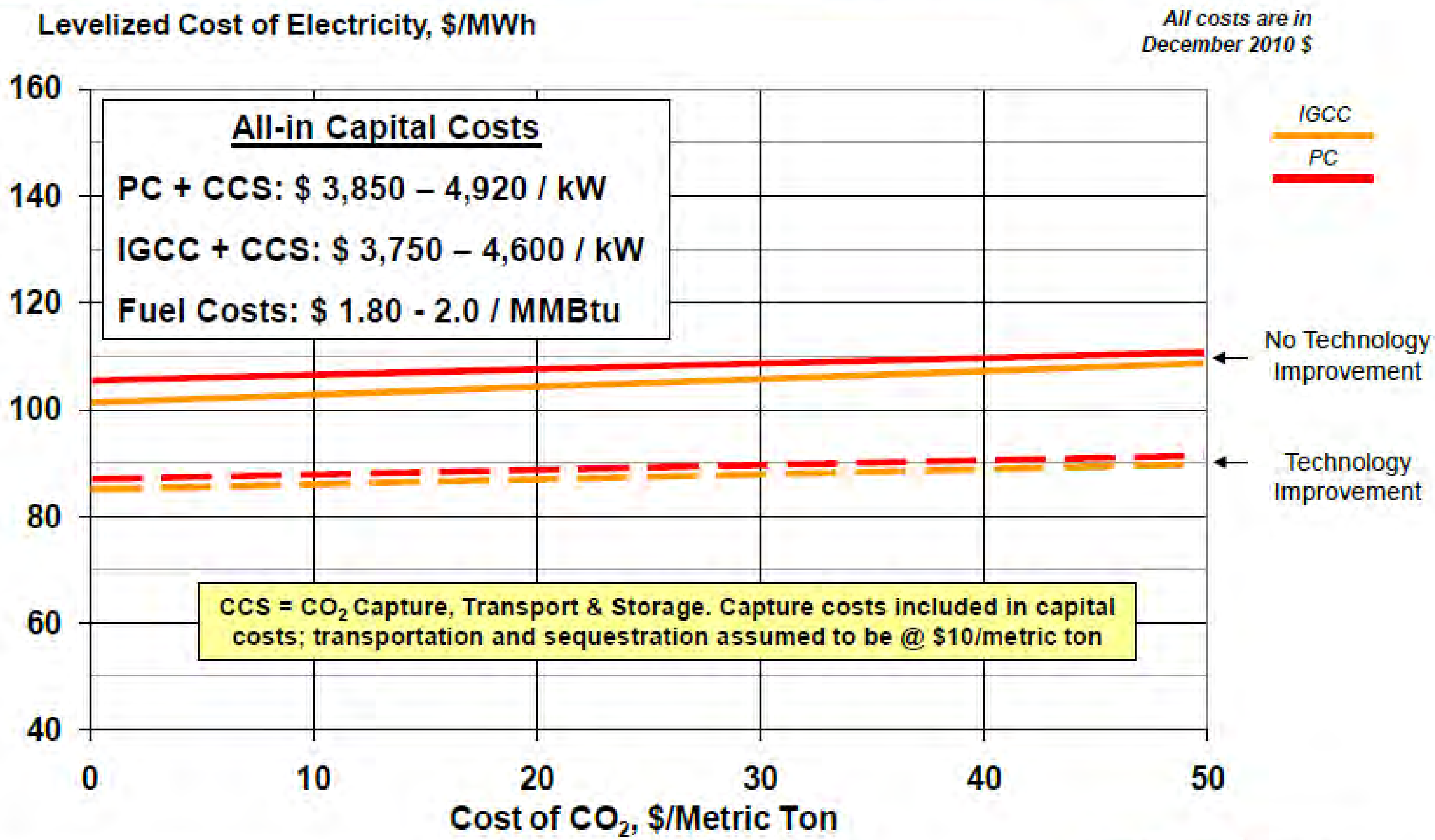
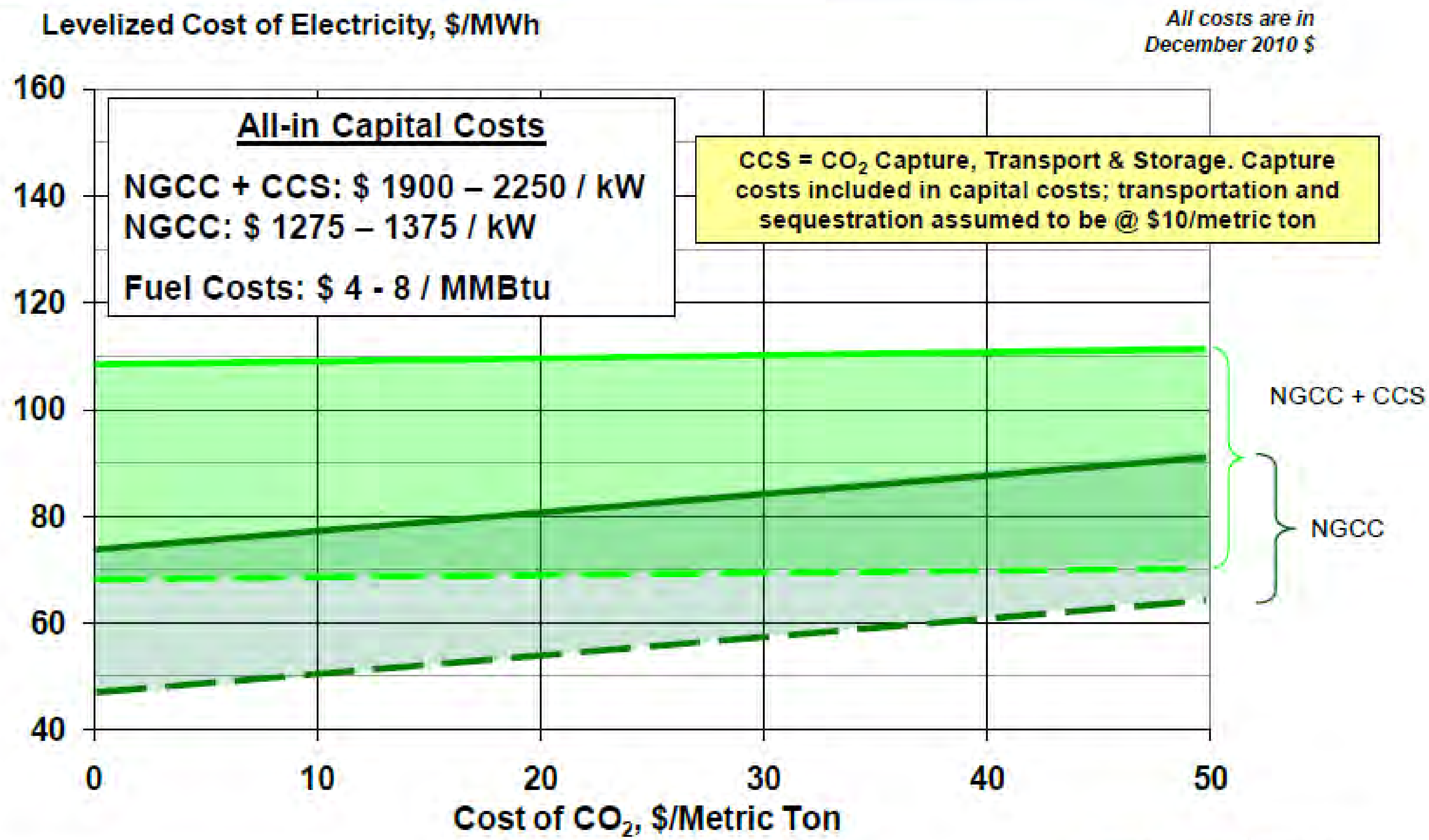
Longer-Term: 2025

Coal, 2025—Impact of CO_2 Capture, Transport & Storage (CCS) and Cost and Performance Improvements on Levelized Cost of Electricity



NGCC, 2025—Impact of CO_2 Capture, Transport & Storage (CCS) on Levelized Cost of Electricity



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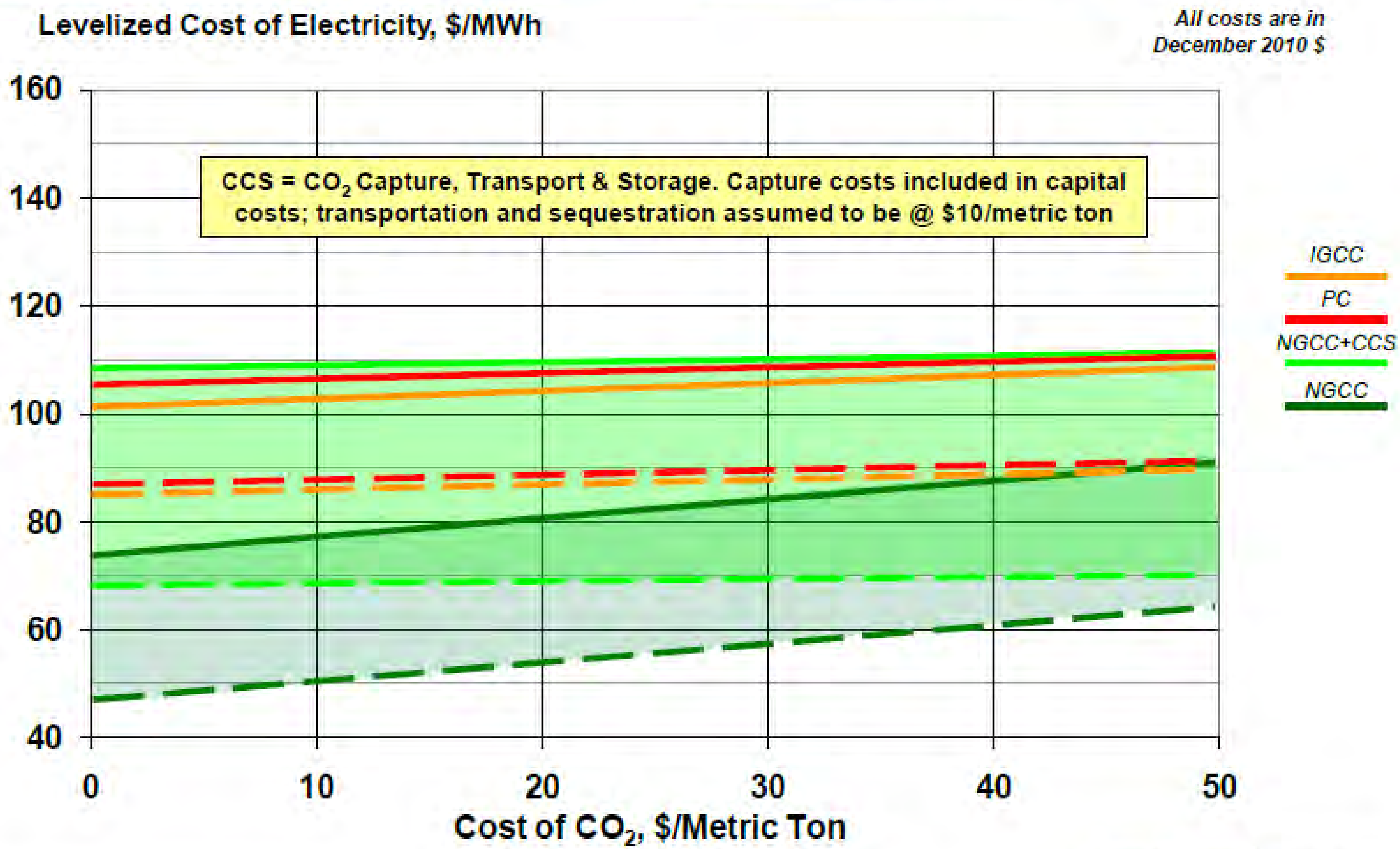
PC, IGCC, NGCC, 2025—Impact of CO_2 Removal, Transport & Storage (CCS) and Cost and Performance Improvements on Levelized Cost of Electricity



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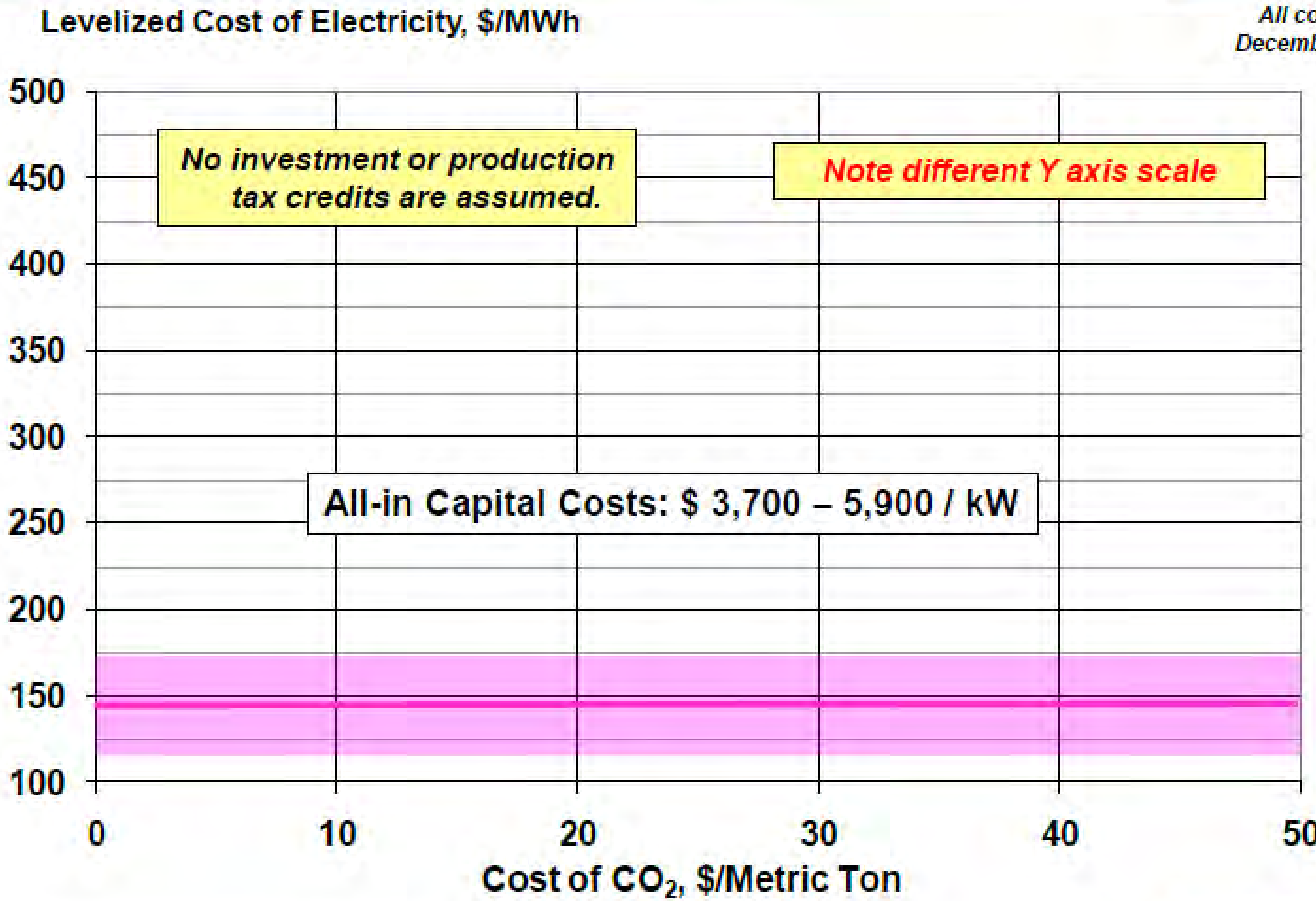
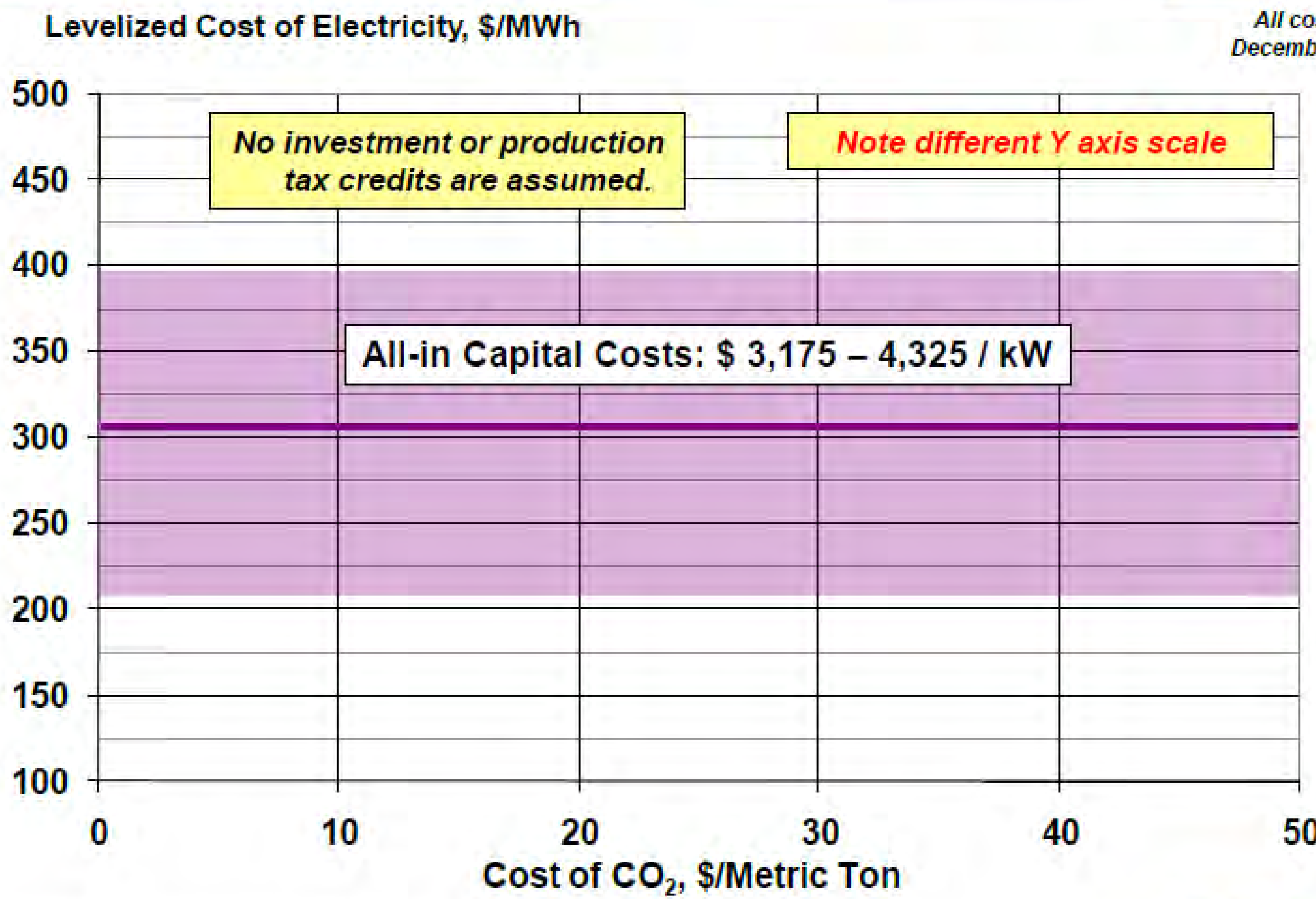
Concentrating Solar Thermal– 2025

All costs are in December 2010 $



Solar Photovoltaic – 2025

All costs are in December 2010 $



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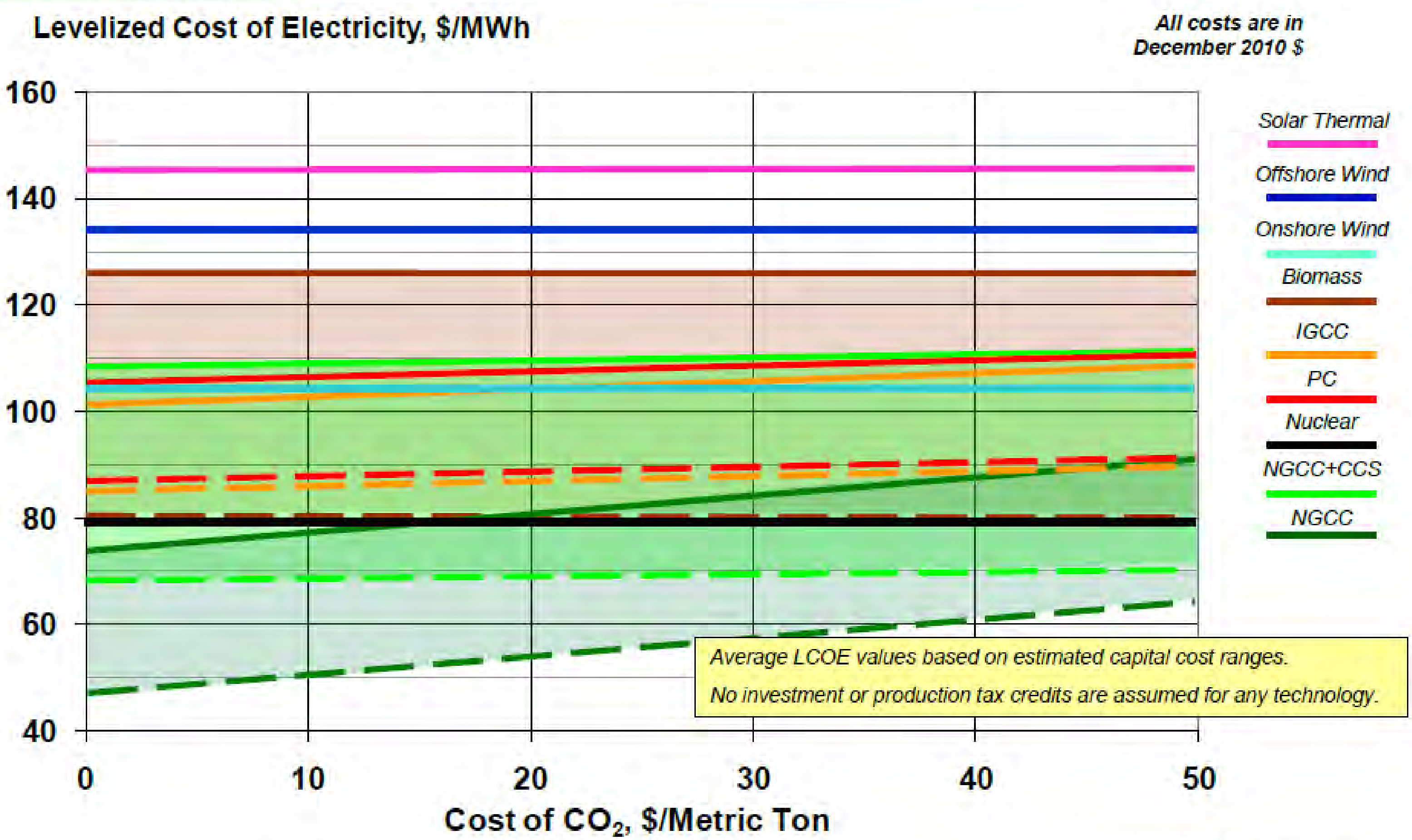
Comparative Levelized Costs of Electricity – 2025



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Closing Thoughts

- Several key uncertainties impact near-term and long-term project decisions and research priorities:
  - Stringency of future CO_2 emissions reduction programs
  - Future price of natural gas (high sensitivity and variability)
  - CO_2 capture and storage technology development and costs
  - Siting requirements
  - Renewable energy technology development
  - Technology-driven escalations and reductions in plant costs
- Demonstrates importance of developing and demonstrating a portfolio of low cost generation technologies.

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A

LEVELIZED COST OF ELECTRICITY CALCULATION ASSUMPTIONS

Table A-1
Financial Assumptions – Non technology-specific, investor-owned utility (IOU) financing rates

Inputs	Rate
Nominal Equity Rate (%)	11%
Nominal Debt Rate (%)	7%
Debt Ratio (%)	50%
Income Tax Rate (%)	39.3%
Inflation Rate (%)	2.5%
Property Tax/Insurance Rate (%)	1.3%
Calculated Values	
Nominal Weighted Average Cost of Capital (WACC)	9.0%
Real WACC (Discount Rate)	5.0%

Table A-2
Life Assumptions (Years) – Technology-specific

Input	Book Life	Debt Life	MACRS Depreciation
SC/USC PC	40	20	20
IGCC	40	20	20
NGCC	30	20	20
Nuclear	40	20	15
Biomass	40	20	7
Wind	20	20	5
Solar Thermal	30	20	5
Solar PV	20	20	5

Table A-3
Unit Construction Duration Assumptions (Years) – Technology-specific

Input	Construction Duration
SC/USC PC	4
SC/USC PC with CCS	4
IGCC	4
IGCC with CCS	4
NGCC	3
NGCC with CCS	3
Nuclear	7
Biomass	3
Wind	1
Solar Thermal	2
Solar PV	1

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