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Program on Technology Innovation: Integrated Generation Technology Options

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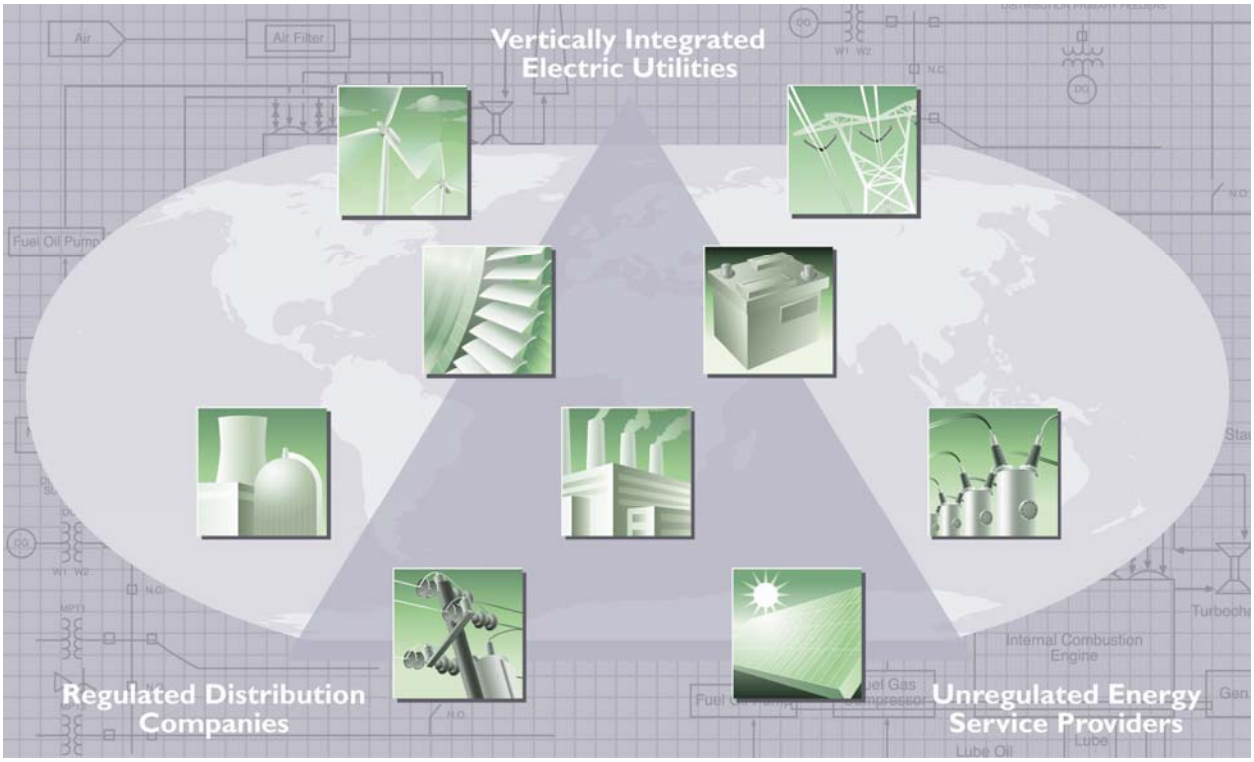

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Technical Update, November 2009

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This is an EPRI Energy Technology Assessment Program report based on 2008 research and 2009 research in progress under EPRI's Technical Assessment Guide (TAG®) Program. This report will be annually updated to be consistent with future research conducted in the EPRI TAG program.

NOTE

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PRODUCT DESCRIPTION

This report provides a snapshot of current cost, performance, and trends for nine power generation technologies in the central station category. In this report, *central station* is defined as >150 MW with the exception of renewable resource-based technologies. In addition to fossil- and nuclear-based technologies, four renewable resource-based technologies are included. This report describes the current options in power generation infrastructure capital investments and updates the results of EPRI studies performed in 2008. This update offers users a public domain reference for generic cost estimates for nine key electricity generation technologies.

Results and Findings

This report focuses on nine key central station technologies of interest to the industry and likely to dominate the future U.S. generation mix over the next two decades. Although renewable technologies are beginning to emerge in the technology mix with government incentives and regulatory requirements, their integration issues on a much larger scale in the utility system are being addressed. Fuel cells and other distributed generation technologies may have a much smaller impact unless there is considerable breakthrough in technology cost and performance.

Planning for and executing new power generation technologies is in a state of flux resulting from the sudden reversal of economic conditions from 2008 to 2009, the emissions and cost uncertainties surrounding technologies, and the challenge in forecasting power demand.

Utilities need a resource that gives them the historical perspective of escalation trends over the last decade. More importantly, utilities need to 1) understand the factors driving the substantial increases in escalation in the last four years, 2) have the data necessary to understand the impact of the recession, with the downturn or flattening of escalation that began to occur in the first quarter of 2009, and 3) have estimates of future escalation that can be used for projects they are planning. This report provides a summary of these types of information.

Forecasting future escalations is challenging. Recent historic events such as the federal government bailout of major financial institutions, the bankruptcy of two of the "big three" automakers, an unprecedented residential home foreclosure rate, and the massive federal stimulus package require a forecasting method that captures ongoing economic uncertainties. This report gives an overview of basic engineering economic methods to compare technology costs on a consistent basis during the current uncertain economic times.

Applications, Value, and Use

With aging infrastructure and the emergence of climate change as new elements of a changing regulatory environment, energy companies and other stakeholders need credible, consistent information on the performance and cost of conventional and emerging electricity technologies. This report, which is based on the EPRI Technical Assessment Guide (TAG®), provides an objective, up-to-date overview of the technical status, performance, costs, and markets for nine

electricity supply technologies. This report serves as a high-level information document on technologies that are currently in "play" in the industry. Comprehensive treatment of a wide range of technologies is provided in the EPRI TAG and addresses uncertainties with respect to:

- The market price for electricity and how it affects return on investment
- Environmental restrictions impacting existing assets
- Technology obsolescence and risk
- The performance characteristics that have the greatest impact on market position

EPRI Perspective

TAG is considered the industry standard and has been an authoritative source of cost and performance information on electricity generation technologies for years. However, the complete version of the TAG is available only to funders of the TAG Program. EPRI is making this report available in the public domain to help meet the demand for credible technical information created by an unprecedented level of activity in planning for power generation and analysis of the electricity sector. Its publication responds to requests from a range of stakeholders to disseminate the TAG information more widely.

The technical basis of this report is ongoing research conducted as part of the EPRI TAG Program, which focuses on issues central to generation planning and project management:

- Analysis, evaluation, and compilation of objective, verified technology data
- Rapid response to executive and regulatory inquiries on technology issues
- Effective planning for new facilities and execution of engineering studies
- Benchmarking siting studies

Approach

The report presents essential information on nine critical technologies in the *central station* category. These are the technologies most widely under consideration for power generation capacity additions. The technical basis of this report is ongoing research under the EPRI TAG Program, which is focused on helping energy companies make sound technology-related investment decisions that are consistent with their long-term business goals. The TAG Program leverages three decades of EPRI experience evaluating the cost and performance of about 20 electricity generation and storage technologies. The annual full version of the TAG update reflects current market trends for various technologies and interests of TAG program advisors.

Keywords

Central station power generation technologies
Technology evaluation
Cost and performance
Technology trends

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1
INTRODUCTION

1.1 Purpose

This section of the 2009 *Integrated Generation Technology Options* describes the report's objectives, intended audience, purpose, and scope.

The information presented in this report provides a concise executive-level overview of near-term (5–10 years) as well as longer term (up to 2025) emerging electricity industry technology costs and performance on a consistent basis. Section 1.9 summarizes these data. Section 1.10 presents plant construction costs from a bulk materials perspective. The purpose of this document is to keep industry executives, policy makers, and other stakeholders informed of current status and trends in electric power generation technologies of current interest. The information is presented in a manner that addresses both the specific needs of strategic planners and upper level management in the energy industry and those of regulatory bodies. This report is a revision to and an update of the Integrated Generation Technology Options report (IGTO-1018329) published in November 2008.

EPRI's Energy Technology Assessment Center (ETAC) funded this report. The report draws on the Technical Assessment Guide (TAG®) to provide an overview of cost and performance estimates of power generation technologies in the following categories:

- Central Stations, including Pulverized Coal, Fluidized Bed Combustion, Integrated Coal Gasification/Combined Cycle, Combustion Turbine/Combined Cycle (with/without CO_2 capture) and Nuclear technologies
- Renewable Resources, including Wind, Biomass, and Solar Thermal and Solar Photovoltaic technologies

For each technology area, the report presents a 1-to 3-page overview of the technologies including:

- A brief description of the technologies
- Survey of the technology development status (key developers and pilot/demo activities)
- Current and projected technology performance and costs
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

The scope of this report includes capital cost, operations and maintenance (O&M) cost, performance data, and technology trends. A comprehensive discussion and description of each technology is also presented. Costs are reported in December 2008 dollars.

Because of the drastic change in economic scenario from the high cost escalation in 2004–2008 time period to a global (except in China and India) recession in 2009, the rationale for the costs presented in this report is as follows:

- Estimates (constant$ December 2008) represent composite material and labor cost percentage increases from December 2007.
- These values are expected to hold good for planning purposes for projects that would have a first year commercial service date in 2015–2020 time frame.
- The preliminary indications of a drop in escalation in the first and second quarter 2009 from published sources is expected to be a temporary phenomena and the price of commodities and labor is expected to revert back to December 2008 levels by the mid-late 2010.
- Project executions in the U.S. is expected to revive in the 2nd quarter 2010 and the on-going projects in cash rich China and India are expected to stabilize the 2008 year end price levels in mid-2010.

Cost and performance estimates are idealized for representative generating units and have been normalized where possible to produce a consistent database. Estimates are not intended to apply to specific energy companies at specific sites since site-specific and company-specific conditions can vary substantially.

In developing these estimates, an effort was made to forecast probable capital expenditures associated with commercial-scale technology projects. Cost estimating involves both analysis and judgment: it relies heavily on current and past data and on project execution plans, which are in turn based on a set of assumptions. The successful outcome of any project—project completion within the cost estimate—depends on adherence to an execution plan and its assumptions without deviation. These estimates represent the ongoing technology monitoring effort at EPRI to update the current TAG® database and information.

The information in this report includes cost increases over the last five years due to heightened worldwide construction activity as well as the downturn in price escalations that resulted from the ongoing worldwide recession. There is a real possibility that costs will remain flat or else continue to decrease in the short term (2009–2015).

1.2 Content

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.

1.3 Expectations

The objectives of the complete version of TAG® are to contain data that is timely, applicable to competitive markets, and of regulatory quality. This last term implies that data pass the "sanity checks and scrutiny" that regulatory bodies are likely to require for representations of the cost or performance of both existing and future technologies. 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® cost estimates are conceptual estimates that differ from site-specific project estimates for a number of reasons:

- Project estimates are more detailed and based on current dollars (with escalation and inflation) with reference to future commercial service date and usually include AFUDC (Allowance for Funds used During Construction).
- Individual companies' design bases, for example, the amount of equipment redundancy included for reliability, vary.
- Owner costs as well as site-specific costs in project estimates are generally higher.
- AFUDC for specific projects is typically greater.
- Site-specific requirements, such as fuel delivery, transition, tie-in, and raw water requirements, also have an impact on the costs.

As presented in Table 1-1 and Table 1-2, two rating systems are used in the TAG® to define an overall confidence level to data presented in technology screening studies. One system is based on a technology's development status; the other is based on the level of effort expended in the design and cost estimate. The confidence levels of the estimates presented in this report reflect demonstration thru mature levels of technologies and a preliminary or simplified level of effort.

Table 1-1
Confidence Rating Based on Technology Development Status

Letter Rating	Key Word	Description
A	Mature	Significant commercial experience (several operating commercial units)
B	Commercial	Nascent commercial experience
C	Demonstration	Concept verified by integrated demonstration unit
D	Pilot	Concept verified by small pilot facility
E	Laboratory	Concept verified by laboratory studies and initial hardware development
F	Idea	No system hardware development

Design/Cost Estimate. The rating system shown below indicates the level of effort involved in the design and cost estimate.

Table 1-2
Confidence Rating Based on Cost and Design Estimate

Letter Rating[a]	Key Word	Description
A	Actual	Data on detailed process and mechanical designs or historical data from existing units
B	Detailed	Detailed process design (Class III design and cost estimate)
C	Preliminary	Preliminary process design (Class II design and cost estimate)
D	Simplified	Simplified process design (Class I design and cost estimate)
E	Goal	Technical design/cost goal for value developed from literature data

1.4 Cost and Technical Data—Uncertainty

Some degree of uncertainty is generally expected in cost and performance data. Because new technologies do not have a history of construction or operating costs, only estimates can be used. Accuracy of such estimates depends on the quality of technical data and the level of effort in the engineering design. Extrapolation of cost and performance data on commercially proven technologies to develop estimates of future performance also incorporates a degree of uncertainty due to the influence of factors discussed in this section. Quantifying uncertainty in estimates can aid in understanding and making judgments about the viability of a technology.

1.5 Sources of 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 phenomena, small sample statistics, or scaling uncertainty.
2. *Estimation*—Uncertainty resulting from estimates based on less-than-complete designs. 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 execute these technologies varies widely depending on the lead time required to obtain environmental permits to engineer and place the order for materials and equipment with a vendor to delivery and construction. For example it may take two to three years for combustion turbine and wind turbine to six to eight years for coal based technologies and up to ten years for a nuclear power plant. This also illustrates the significant difference in the bottom line of a constant dollar versus current dollar analysis (see discussion in section 1.8).
3. *Economic*—Uncertainty resulting from unanticipated changes in cost of available materials, labor, or capital. The effect of short term financing for project execution and eventually financing of the plant for its operating life is linked to the project duration. The debt/equity ratio, the return on equity, cost of debt, the book life and tax life are some of the factors that play an important part in the final cost estimate for the project. The ongoing worldwide recession compounds all traditional aspects of this type of uncertainty.
4. *Other*—Uncertainties in permitting, licensing and other regulatory actions, labor disruption, 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. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The bandwidth of the uncertainty depends on the number of new and novel parts in a technology and the degree of scale-up required to reach commercial size. The status of technology, based on the maturity of its components is critical in meeting the cost and performance estimates scaling up from pilot to demonstration to commercial. The following figure illustrates the sequence of steps and the potential impact on cost:

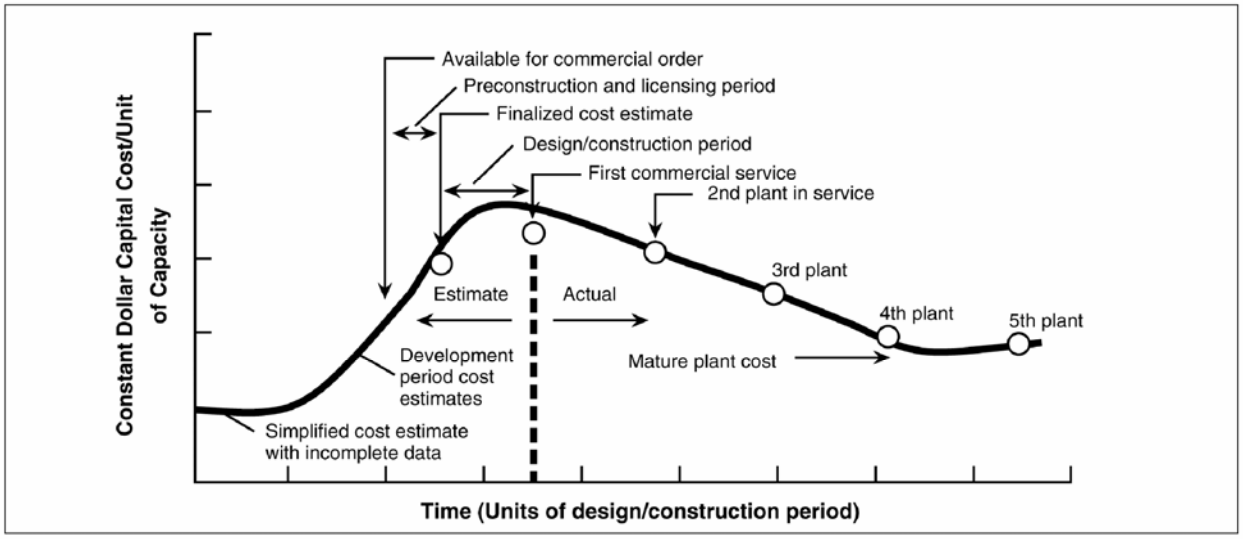


Figure 1-1
Capital Cost Learning Curve

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
- Some unanticipated operating problem that becomes significant

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.

Large differences between original cost estimates and actual installed costs have been common. Some of these differences have resulted from the type of estimate given, such as a "goal" type of estimate, without explicit consideration of the likelihood of achievement. Quantifying uncertainty should be an explicit part of developing cost estimates to reduce such misunderstandings.

1.6 Accuracy

Because of the substantial impact of local conditions, power generation cost estimates in this report necessarily fall into the simplified or preliminary classifications. When compared with finalized or detailed cost estimate values, these may vary by 30–50%. However, since a consistent methodology is used for developing these simplified cost estimates, these costs are useful in performing screening assessments for comparing various alternative technologies of power generation.

1.7 Accuracy Ranges

Accuracy of cost estimates has been discussed in detail in many texts and papers on cost estimating. Estimates of the range of accuracy for the cost data presented in this section are shown below. This table is based on the confidence ratings described in the preceding subsection.

Accuracy ranges can be useful in indicating the overall degree of confidence in a given estimate. Applying accuracy ranges to comparisons of two generating alternatives may show overlapping costs. However, both alternatives may have many factors in common, for example, construction labor rates, materials, and components. Upward movement in these factors would cause both alternatives to cost more, and their cost differential would not change significantly.

If a comparison of alternatives incorporating the accuracy ranges produces no overlap, this finding would probably not be reversed in a formal uncertainty analysis. However, in themselves, accuracy ranges do not supply sufficient data to compare technologies in an uncertainty analysis.

The current uncertainties in cost escalation, due to high demand for bulk materials such as piping, structural steel, and concrete has broadened the accuracy ranges in Table 1-3. For a mature technology with a simplified estimate the accuracy range is currently about -10 to +30%.

The following discussion on current dollars versus constant dollars is intended to clarify some of the confusion related to the current expression of cost estimates published in the public domain.

Table 1-3
Accuracy Range Estimates for Technology Screening Data [a] (Ranges in Percent)

Estimate Rating		A Mature	Technology Development Rating			E and F Lab and Idea
			B Commercial	C Demo	D Pilot	
A.	Actual	0	–	–	–	–
B.	Detailed	-5 to +8	-10 to +15	-15 to +25	–	–
C.	Preliminary	-10 to +15	-15 to +20	-20 to +25	-25 to +40	-30 to +60
D.	Simplified	-15 to +20	-20 to +30	-25 to +40	-30 to +50	-30 to +200
E.	Goal	–	-30 to +80	-30 to +80	-30 to +100	-30 to +200

[a] This table indicates the overall accuracy for cost estimates. The accuracy is a function of the level of cost-estimating effort and the degree of technical development of the technology. The same ranges apply to O&M costs.

In TAG analysis, accuracy ranges are not applied to overall cost estimates directly for an upper and lower bound; rather these are used in a Monte Carlo simulation with assigned probability ranges to determine the actual range to be applied to the estimate. The capital cost estimates for various technologies summarized in this report are based on the results of Monte Carlo simulations performed as part of TAG program research. The process is described in more detail below for an IGCC plant

example. The TAG program uses this approach to so that differing levels of uncertainty for components of technology costs can be treated quantitatively.

Each major component/subsystem of the plant (e.g., the gasifier, the air separation unit, the power island, etc.) is assigned a probability distribution. For a -20% to +30% range, this distribution would look like Figure 1-2, where -20% is equivalent to a 0.8 multiplier and +30% is equivalent to a 1.3 multiplier.

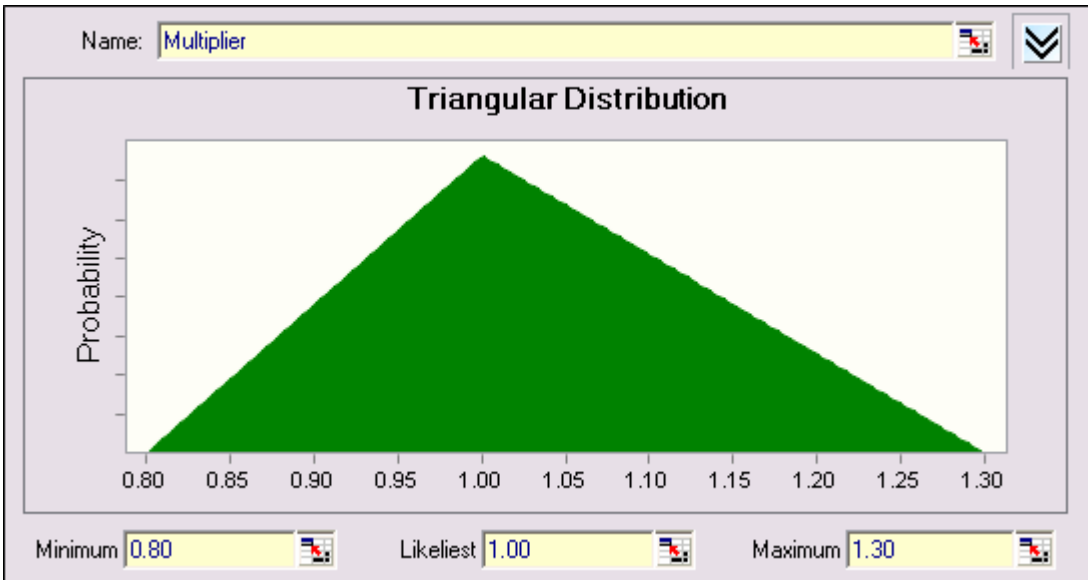


Figure 1-2
Probability Distribution for -20% to +30%

The Monte Carlo simulation selects multipliers from within the probability distribution range with a different multiplier for each unit of the plant. For example, in one run the gasifier cost may be increased by 20% with a 1.2 multiplier while the air separation unit (ASU) cost is decreased by 5% with a 0.95 multiplier; on the next run, the gasifier may be increased by 5% with a 1.05 multiplier while the ASU is increased by 15% with a 1.15 multiplier. As the simulation runs through thousands of scenarios within the probability distribution, the total plant cost for a given set of multipliers is calculated and recorded in the software. At the end of the simulation, these total plant cost results are compiled and a capital cost range can be determined.

Figure 1-3 shows an example of Monte Carlo simulation results for the construction management and field procurement component of a solar thermal power plant. The low end of the results at $7,089 is about 9% lower than the base estimate and the 90% confidence value at $8,558 is about 7% higher than the base estimate. Therefore, this estimate has a -9%/+7% range for the capital costs.

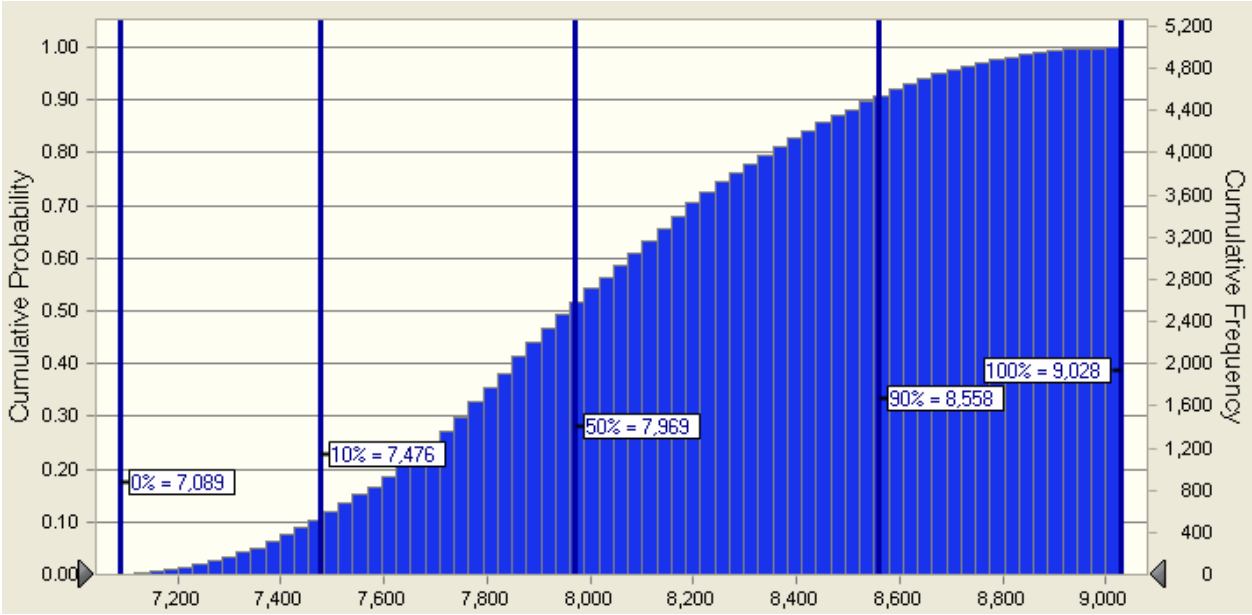


Figure 1-3
Monte Carlo Simulation Cumulative Frequency Example

The capital costs shown for the nine technologies in this technical update are based on TAG research using the above methodology and represent costs based on a national average of six regions of the U.S. at a 90% confidence level.

1.8 Current versus Constant Dollars

Analysts can conduct an economic analysis in current dollars by including the effect of inflation or in constant dollars by not including inflation. In general, utility engineering economic analyses are made in current dollars because the numerical values of the estimated costs will more closely approximate the actual costs when they occur. Therefore, the values from a current-dollar analysis can form the basis for budgeting future expenditures.

Constant dollar analysis is often used in comparing technologies to recognize the potential for advancement of a component or components through research and development (R&D) for improved performance and cost reductions. As R&D involves a longer time-frame, the effect of uncertainties such as inflation may tend to cloud such an assessment. For example, research on the components of a nuclear power plant in terms of better, lighter materials, research on pre-fabrication techniques etc., may speed up the actual project schedule thereby reducing the cost. In this context, the focus is not on project feasibility and execution (where the current dollar analysis may be important) but rather working towards a R&D program to improve technology performance overall.

Since both current- and constant-dollar analysis fulfills a purpose, this subsection delineates the characteristics of each method and discusses their advantages and disadvantages. Both types of analysis often use cost levelization. This averaging technique uses present value arithmetic that converts a cost whose value varies with time to an equivalent cost that is constant over time.

Both terms are expressed with respect to the anticipated commercial service year of a plant (e.g., overnight in constant 2007 dollars or in future current dollars for a 2015 service date).

1.8.1 Current-Dollar Analysis

Current-dollar analysis includes expected effects of inflation on capital carrying charges and operating costs.

- Advantages
    - Used by most utilities in evaluating their business investments
    - Presents cash flows that include inflation effects and that are estimates of values eventually appearing in budget statements and other company financial documents
- Disadvantages
    - Appears to overemphasize operating and fuel costs
    - Makes levelized values often appear higher than today's values over the life of the generating unit
    - Obscures real cost trends as a result of masking by inflation effects
    - Due to the time value of money, the effect of economic and financial uncertainties can be much more significant in a current dollar basis than in a constant dollar basis. This is particularly true for a technology implementation with longer project duration and with uncertainty in escalation.

1.8.2 Constant-Dollar Analysis

Constant-dollar analysis does not incorporate inflation effects in capital carrying charges and operating cost projections.

- Advantages
    - Generally preferred by economic analysts
    - Makes levelized values appear close to today's values and enables better intuitive understanding
    - Clarifies real cost trends
    - The best computational method is usually to project current dollar revenue requirements, de-escalate each year's costs, and calculate the present value with the real discount rate. This approach assures that the present value is the same whether the analysis is performed in current or constant dollars.
- Disadvantages
    - Presents cash flows in reference-year dollars, which may be significantly lower numerically than actual values (current dollars)
    - Appears to understate capital carrying charges

- Presents options as less costly than they ultimately will be
- Requires a more complex analysis. Measurement of inflation is a difficult and inexact process. Inflation varies over time thus requires complicated mathematics to determine a discount rate that would also vary over time. The real interest rate is an abstract concept that may be difficult to understand.
- Some costs are unresponsive to inflation, for example: debt service, depreciation, income tax depreciation, costs locked in under contract, and lease payments. A constant dollar analysis requires that inflation be "taken out" of these costs as well as those variable costs that are subject to inflation. This calculation leads to abstract values such as "hypothetical constant dollar" debt service that may be difficult to interpret.
- Constant dollar analysis does not avoid the need to project future inflation since inflation needs to be factored out of the discount rate.

1.8.3 Choice of Method

The choice 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.

A recent filing with a public utilities commission for a nuclear power plant illustrates the difference between project specific, constant dollar and current dollar estimates. The filing is by an electric utility for a project specific estimate in current dollars for a commercial service date of 2015 and the comparison is with a generic estimate in TAG in constant dollars for a hypothetical commercial service date of 2009. The electric utility starting basis for the estimate is in 2008$ and projected escalation, short term project finance charges and site specific costs are included in the estimate.

Table 1-4
Cost Estimate in Constant and Current $

Key Cost Elements	Utility site specific project (2015$)	TAG Constant $ (2008$)	TAG Current $ (2015$)
Process Capital Cost (Equipment & Construction Labor)	2152[(A)]	2479	2479
General Facilities & Site Specific Costs	315[(B)]	111	111
Engineering & Construction Management	340	410	410
Contingency	470	561	561
Owners Cost	323	384	384
Total Overnight Cost	***3600***	**3945**	**3945**
AFUDC (Allowance for Funds Used During Construction) - Short term Project Financing	1837[(C)]	915	1490
Escalation	892[(D)]	0	1144
Total	**6329**	**4860**	**6579**

[(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 11.4%
[(D)] –scalation at 2.5% per year

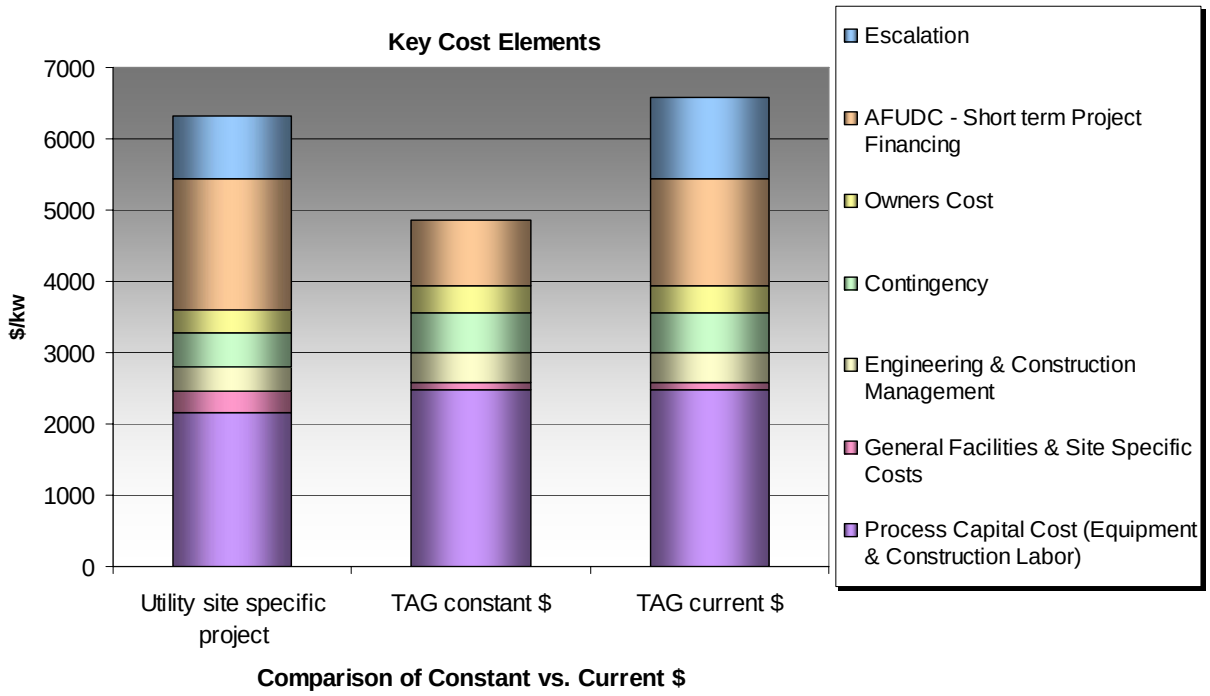


Figure 1-4
Key Cost Elements in Constant $ and Current $

The above example also illustrates the difference between a site specific project estimate and a generic project estimate. The differences are easily identifiable. The noticeable difference in AFUDC is also due to what is known as 'front-loading', i.e. a significant portion of the project financing is allocated in the first few years of project which accrue a larger interest than if it were allocated in 'middle-loading' or 'back-end loading.

In comparing different technology options, the most economical option will be apparent regardless of which method is chosen. Current-dollar analysis more closely approximates future cash flows, which is important when utilities are reviewing estimates with regulatory authorities and security analysts. Constant-dollar analysis gives a clearer picture of real cost trends and purchasing power differences. 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.

In this report, the constant dollar method is used so that the technologies are compared on an 'overnight' construction basis, meaning the start of commercial service date is the same. The disparities in construction duration requirement for the plants are normalized in this approach. 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 importance of different evaluation criteria may differ from one project to another.

1.9 Bulk Percentages and Quantities for Generation Technologies

As mentioned previously in Section 1.8, a basic assumption in this report is that, for planning purposes, we have assumed the escalation and the projected capital costs at the end of December 2008 with moderate escalation will hold good for new plants coming into service in 2015 and beyond. We define this as the upper bound cost scenario. Given the current recession and its effect on escalation uncertainty and the reported actual decline in escalation for some of the power plant bulk materials (such as structural steel, piping etc) we have a lower bound cost scenario. In the lower bound cost scenario we have assumed that there would be an 8% decline in costs for the power plant and there would be moderate escalation from 2010 onwards. Construction costs for fossil and nuclear power plants can be escalated by evaluating the escalation/de-escalation of power plant equipment and bulk materials and labor components.

In the following example, the labor and material costs associated with each bulk item of a 1380 MW Advanced Nuclear Boiling Water Reactor (ABWR) are escalated through 2015. Two forecasts, a high and a low, were generated. In the high case, annual escalations for labor and material costs were 5% and 2.5%, respectively and the baseline cost at the end of 2008 is the starting point In the low case, the same escalations were applied with the baseline cost being the current de-escalation of costs reported by an A/E firm and by one of the construction cost indices at about 8% Baseline costs were based on criteria and associated cost estimates in published reports from the public domain and data on the costs provided by EPRI (from 2008).

Table 1-5
A generic example of ABWR Process Capital cost estimate breakdown for low and high cost scenarios

		Cost $/kW			% of total costs	
		2008	2015, low	2015, high	2008	2015
Structures & Improvement	Labor	$278	$343	$391	13%	14.4%
	Materials	$256	$274	$305	12%	11.5%
Electrical	Labor	$43	$53	$60	2%	2.2%
	Materials	$128	$137	$152	6%	5.8%
Reactor Plant Equipment	Labor	$85	$105	$120	4%	4.4%
	Materials	$598	$638	$711	28%	26.9%
Turbine Plant Equipment	Labor	$64	$79	$90	3%	3.3%
	Materials	$427	$456	$508	20%	19.2%
Main Heat Reject System	Labor	$43	$53	$60	2%	2.2%
	Materials	$107	$114	$127	5%	4.8%
Miscellaneous Plant Equipment	Labor	$43	$53	$60	2%	2.2%
	Materials	$64	$68	$76	3%	2.9%
TOTAL		$2,137	$2,372	$2,662	100%	100%

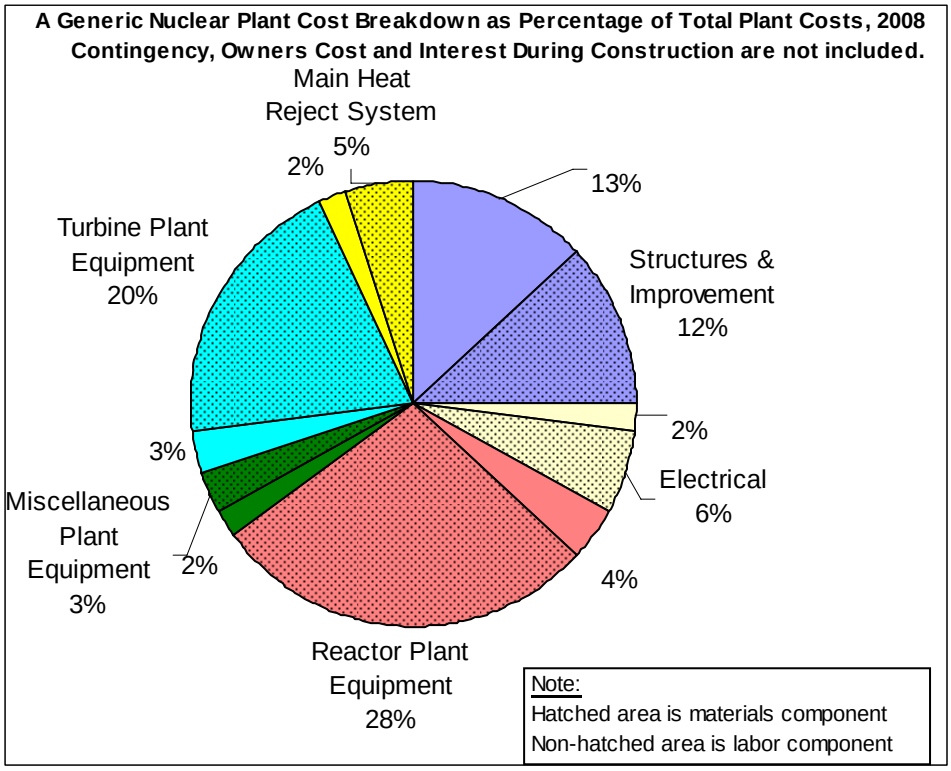


Figure 1-5
A Generic Nuclear Plant Cost Breakdown as Percentage of Total Plant Costs

1.10 Representative Cost and Performance of Power Generation Technologies

The following tables provide estimates of the representative cost and performance of power generation options for the year 2015 (Table 1-6) and 2025 (Table 1-7).

Table 1-6
Representative Cost and Performance of Power Generation Technologies (2015)

All Costs in Constant Dec. 2008$	Efficiency (%)	Capacity Factor (%)	Capital Cost (Dec. 2008 $/kW) TCR*†	Levelized Cost of Electricity (LCOE) (2008 December Constant $/MWh) †	CO_2 Emissions (Metric Tons Per MWh)	Sources/Assumptions
SCPC (Supercritical Pulverized Coal) - no CO_2 capture	38	80	2650	66	0.86	Plant size = 600–750 MWe Data represents averages for different coal types at various regions in USA. Fuel cost $15/MWhr included in LCOE.
IGCC (Integrated Gasification Combined Cycle) – no CO_2 capture	38	80	2960	71	0.83	-Fuel cost = $1.8 MMBtu -All efficiencies are higher heating value (HHV). -Plant size = about 800 Mwe. Fuel cost $14/MWhr included in LCOE
CTCC (Combustion Turbine Combined Cycle) (Natural Gas @ $8–$10/MM Btu)	47	80	880	74–89	0.38	-CTCC unit based on GE 7F machine or equivalent by other vendors. Data represents averages for various regions in USA. Capacity factor represents technology capability. -All efficiencies are higher heating value (HHV). Fuel Cost $57 - $72/MWhr ($8 - $10/MMBtu) included in LCOE
Nuclear	33	90	4860	84	None	-Plant size = 1400 MWe. Nuclear Fuel cost 0.80/MMBtu -EPRI TAG® sensitivity studies of all-in costs. Values shown are averages of high and low ends of data range. -Data represents averages for various regions in USA. Fuel cost $8/MWhr included in LCOE.
Wind	N A	35.0	2350	99	None	-Plant size = 100 MWe -LCOE corresponding to 35% capacity factor, consistent with current fleet average. -Data represents averages for various regions in USA.
Biomass CFB @ $1.22–$2.22/MMBtu	28	85	3580	77-90	0.1	-Plant size = 75 MWe -High COE results in part from low fuel heat content and high collection costs. Data represents averages for various regions in USA. -Efficiency is based on higher heating value (HHV).Fuel Cost $15 -$28/MWhr ($1.22 - $2.22/MMBtu) included in LCOE.
Solar Thermal Trough	13.5% (solar to electric)	22	4851	290	(1) None	Plant size = 125 MWe. New Mexico. Three scenarios: 1) wet Cooling, 100% solar, 2) 6 hours storage, dry cooling 3) wet cooling, 10% CT, $8/MMBTU.
		34	6300	225	(2) None	
		32	5349	258	(3) 0.219	
Solar Photovoltaic	10%	26	7981	456	None	Plant size = 20 MW Fixed Flat-Plate

*TCR –Total Capital Requirement (also known as 'All-In' costs). CTCC is also referred to as NGCC (Natural Gas Combined Cycle)

† **EPRI and the DOE are developing a road map to improve technology performance and reduce capital and levelized costs of electricity.**

Table 1-7
Representative Cost and Performance of Power Generation Technologies (2025)

All Costs in Constant Dec. 2008$	Efficiency (%)*	Capacity Factor (%)	Capital Cost (Dec. 2008 $/kW) TCR*	Levelized Cost of Electricity (LCOE) (2008 December Constant $/MWh)*	CO_2 Emissions (Metric Tons Per MWh)*	Sources/Assumptions
SCPC w/CO_2 capture	27	80	4435	101	0.124	Plant size range = about 550–750 MWe. Data represents averages for different types of coals at various regions in USA.
SCPC w/CO_2 capture; with cost and performance improvements	33	80	3678	86	0.1	Fuel cost = $1.8 / MMBtu. Assumed 90% CO_2 removal will require technology advances over current state of the art.
IGCC w/CO_2 capture	31	80	4083	92	0.1	All efficiencies are based on higher heating value (HHV).
IGCC w/CO_2 capture; with cost and performance improvements	34	80	3317	78	0.1	Based on EPRI Coal Fleet Program studies and results.
CTCC – (Natural Gas @ $8–10/MM Btu)	54	80	902	67-81	0.35	Plant size = about 800 MW; no CO_2 capture and sequestration. CTCC unit based on GE 7H machine or equivalent by other vendors. Capacity factor represents technology capability. Data represents averages for various regions in USA. All efficiencies are higher heating value (HHV).
Nuclear- Economically Simplified Boiling Water Reactor (ESBWR)	33	90	4127	74	None	Plant size = 1500 MW Nuclear fuel cost: $0.80/MMBtu EPRI TAG® sensitivity studies of all-in costs. Values shown are averages of high and low ends of data range. Data represents averages for various regions in USA.
Wind	N/A	42	2350	82	None	Plant size = 100 MW LCOE corresponding to 42% capacity factor, consistent with anticipated fleet average. Data represents averages for various regions in USA. Plant size = 75 MW
Biomass CFB	28	85	3580	77	0.1	Net emissions of 0.1 metric tons per MWh are assumed to result from incomplete closure of fuel cycle. Data represents averages for various regions in USA. Efficiency is based on higher heating value (HHV).
Solar Thermal Trough	13.5% (solar to electric)	22	4851	290	None	Plant size = 125 MWe. New Mexico. Three scenarios: 1) wet, 100% solar, 2) 6 hours storage, dry, 3) wet, 10% CT, $8/MMBTU.
		34	6300	225	None	
		32	5349	258	0.219	
Solar Photovoltaic	10%	26	7981	456	None	Plant size = 20 MW Fixed Flat-Plate

* EPRI and the DOE are developing a road map to improve technology performance and reduce capital and levelized costs of electricity.

Tables 1-6 and 1-7 (continued)
Representative Cost and Performance of Power Generation Technologies (2015 and 2025)

Notes for Table 1-6 and Table 1-7:

For PC, IGCC, CFBC and CTCC, the potential lack of cooling water in the future would require an assessment and consideration of dry/hybrid cooling.

Variables which influence cost estimates are: direct/indirect cost, owners cost, contingency, interest during construction (also known as AFUDC- allowance for funds used during construction), plant substation, transmission interconnection to grid, gas pipeline, rail-spur within plant and interconnection to main line, and raw water intake structure and pipeline. The estimates include a nominal value for each of the variables based on TAG Methodology.

Since the Levelized Cost of Electricity (LCOE) is based on a constant dollar (Dec. 2008) basis, no inflation/escalation for fuel, capital cost and O&M is assumed. The weighted cost of capital on a constant dollar basis, after tax, is 5.5%, and a 30 year plant life with 15 year accelerated depreciation was used.

Levelized cost of electricity (LCOE) values include estimated capital costs, fuel costs, and variable and fixed operations & maintenance (O&M) costs. Estimated Total Capital Requirement (TCR) costs are based on overnight capital costs + estimated project/site-specific costs, and owner's costs (e.g. start-up, inventory, royalties, land, and interest during construction). Capital costs based on data compiled by EPRI Coal Fleet for Tomorrow, Technical Assessment Guide (TAG®), Renewable Technology and Nuclear research programs and U.S. Department of Energy's National Energy Technology Laboratory (DOE – NETL).

For non-coal technologies, COE values are based on the most comprehensive TCR values available.

The estimates do not include finite escalation (i.e. beyond 2008).

Mercury removal is included in the Coal Technologies.

Methodology incorporates technology and cost uncertainties in major elements of technology such as CO_2 capture, gasifiers and nuclear reactors and these uncertainties will be reflected in the 2008 TAG® report.

All capital costs reflect +15% to +50% uncertainty range for various components of the technologies based on the level of maturity of components (e.g., SCPC boiler-mature (+30%), IGCC Gasifier-Demonstration (+50%), etc.

Data Sources: EPRI Technical Assessment Guide (TAG®) program & EPRI Coal Fleet for Tomorrow, Renewable Technology and Nuclear research programs and DOE/NETL Study, DOE/NETL – 2007/1281- *Cost & Performance Baseline for Fossil Energy Plants*.

TCR –Total Capital Requirement (also known as 'All-In' costs)

TCR does not include Production Tax Credits, Investment Tax Credits, loan guarantees or other incentive programs which reduce capital requirements.

2
PULVERIZED COAL (PC)

2.1 Description

Pulverized Coal (PC) plants have continued to develop over the last decade. In the United States, most PC plants have used standard, subcritical operating conditions at 16.5 MPa/538°C (2400 psig/1000°F) superheated steam, with a single reheat to 538°C (1000°F). Since the early 1980s, there have been 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) steam cycles around the world. SC units typically operate at 24.8 MPa (3600 psig), with 565 – 593°C (1050 – 1100°F) main steam and reheat steam temperatures. On average, these SC units have heat rates that are about 7 to 8 percent lower than subcritical units. Steam temperatures above 565°C (1050°F) are often referred to as ultra supercritical (USC) conditions.

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 units.

The choice of subcritical cycles for coal plants that have been built in the United States in the last 20 years has been mainly due to relatively low fuel costs. Low fuel costs have eliminated the cost justification for higher capital costs of higher efficiency cycles, such as SC. In the international markets, where fuel cost is a higher fraction of the total Cost of Electricity (COE), the higher efficiency cycles offer advantages that can result in favorable COE comparisons and lower emissions compared to subcritical plants. Of the more than 500 SC units in the world, 46% are in the former USSR, 12% are in Europe, and 10% are in Japan. Almost 1/3 of SC units are in the United States. However, all of these U.S. units were built prior to 1991. Although a few have recently been announced, none have been built since, whereas there has been considerable activity with new SC units in Europe and Japan in the past decade.

The selection of SC versus a subcritical cycle is still dependent on many other site-specific factors, including fuel cost, emission control requirements, capital cost, load factor, local labor rates, and expected reliability and availability. With extensive favorable experience in Europe, Japan, and Korea with SC steam cycles during the last decade, their superior environmental performance, and the relatively small cost difference between SC and subcritical plants, it has become more difficult to justify new subcritical steam plants.

In the late 1950s, the first units operating at supercritical pressures were introduced, initially in the United States and Germany. American Electric Power put the Philo supercritical unit in service in 1957; and Philadelphia Electric soon followed with Eddystone 1, a unit still in active service. Today, worldwide, more than 500 supercritical units are operating with ratings from 200 MW to 1300 MW. Steam pressures for these units are typically 240 bar (3500 psi), most of them being single reheat designs. Steam temperatures are usually limited to about 594°C (1100°F) to utilize all-ferritic materials for thick wall components. A few, for example, Eddystone, use higher steam temperatures. Increased pressures and temperatures provide significant efficiency improvements over subcritical units, with associated reductions in environmental emissions of SOX, NOX, CO2, and particulates.

Supercritical units with nominal 4000-psig/1100°F/1100°F steam conditions have an efficiency that is about two percentage points better than conventional subcritical units (2400 psig/1000°F/1000°F). Supercritical units are important to the U.S. market and should be included in feasibility studies evaluating new generation. Their improved efficiency translates to about 5% lower emissions of SO_2, NO_X, mercury, and CO_2. In addition, their improved efficiency results in lower costs for fuel and other consumable items. The savings in operating costs need to be contrasted against the slightly higher capital cost of the boiler and steam turbine. On the other hand, the improved efficiency results in lower flue gas flow and somewhat smaller and less costly emissions control equipment. In addition, problems experienced with the first-generation U.S. supercritical in the 1960s and 1970s have been overcome. Changes in U.S. operating philosophy and advances incorporated in overseas units have resulted in second-generation units with availability and reliability equivalent to subcritical units.

While improvements in boiler and turbine materials and designs have resulted in higher efficiency and availability, the continued addition/retrofit of emission control systems to meet progressively stringent emission standards has had a significant impact on unit performance and cost. Most new PC units use flue gas desulphurization (FGD) systems based on wet limestone scrubbing with forced oxidation (LSFO) to control SO_2 emissions. With more than 25 years of full-scale commercial implementation of this technology, it has become more reliable and less costly. Combustion modifications for reducing NO_X emissions from existing units have been widely implemented, primarily due to the acid rain provisions of the Clean Air Act Amendments of 1990. Retrofit of dozens of selective catalytic reduction (SCR) systems for post-combustion NO_X control resulted from EPA's State Implementation Plan call for NO_X reductions to reduce interstate transport of NO_X, primarily in the eastern states. The performance of these emission control technologies has continued to improve.

Potential reductions in greenhouse gas emissions, particularly for CO_2, have also gained significant attention. For coal-based technologies, one available option to reduce CO_2 emissions per unit of power produced is to increase the unit's efficiency, so that less coal is burned per MWh generated. These increases could be accomplished by retiring an older subcritical unit and replacing it with a more efficient boiler (SC or USC). For example, an advanced USC plant with an efficiency of 46 – 48% (higher heating value, or HHV) would emit approximately 18 – 22% less CO_2 per MWh generated than an equivalent-sized subcritical PC unit. Of course, this reduction also would apply to emissions such as SO_2 and NO_X since the more efficient plant would fire less coal to produce the same energy. It is estimated that if the next 10-GW of coal fired plants were to be built using more efficient supercritical technology, CO_2 emissions would be about 100-million tons less during the lifetime of those plants. This reduction would be

possible even without installing a system to remove the CO_2 from the exhaust gases. In the event that CO_2 capture is required, an advanced USC plant would have 18 – 22% less flue gas to be treated and CO_2 to be captured compared to an equivalent-sized subcritical PC plant.

In 2007 the frenzy to plan for and build new coal-fired power generation units hit a snag due to concerns about the technical and economic viability of CO_2 capture and sequestration. Because of this concern more than 50% of coal power capacity announced since 2000 has been cancelled. In addition to CO_2 emissions, the key issues are high capital cost and the electric utilities ability to finance projects. As a result, investment banks have reportedly drafted a "Carbon Principles" document, which will require owners to prove plants will be economically viable under future CO_2 emission limits. In response, utilities are offering to retire old inefficient coal units with approval of new efficient ones. The reality of the situation is that even with high natural gas prices, there are few options besides natural gas combined cycle (NGCC) to replace capacity from cancelled coal plants.

Some investment banks have concluded that the U.S. government will cap greenhouse-gas emissions from power plants sometime in the next few years and hence have set criteria for lending to a coal based power project. Banks will:

Require utilities seeking financing for plants to prove the plants will be economically viable even under potentially stringent federal caps on carbon dioxide.

Ask companies seeking financing for new U.S. coal plants to:

- Look at energy-efficiency options
- Look at renewable-energy options
- Assess whether the plant design and nearby geology would allow CO_2 emissions to be captured and stored underground

Require utilities to use conservative assumptions about how many emission "allowances" the plant would get from the government under a greenhouse-gas cap

Require utilities to ensure the plant will be allowed to charge electricity rates that are high enough to cover the cost of buying emission allowances

2.2 Technology Summary

Table 2-1 is a summary of ongoing TAG® update work. It lists:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

2.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1, Introduction, the cost for a PC unit varies widely depending on such factors as coal type, regional considerations, site-specific conditions, and owner design philosophy. EPRI TAG® presents cost data by six NERC regions, by three coal types, and includes generic site specific costs such as substation and cooling water intake structure. The cost data presented in Table 2-1 represents the range for the above conditions. In general, PC units based on low sulfur bituminous coals found in the northeast United States are lower in capital cost and operating and maintenance (O&M) cost. However, this lower cost is moderated somewhat due to the cold climate of the northeast that warrants certain design conditions for efficient operation.

The major capital, operation, and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site-specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Coal quality variations that impact design, storage, and delivery (transportation)
4. Owner design and operating philosophy
5. Technology supplier (vendor) design offerings

Table 2-1
Pulverized Coal – Technology Summary

	Advanced-Subcritical PC	Conventional-Supercritical PC	Advanced (Ultra) Supercritical PC
	2400 psig/1050 F/1050 F built in the 1970s – 2000s	3500 psig/1000 F/1000 F built from the 1960s – 1980s 3600 psig/1050F/1050F built in the 1990 – 2000s	3700 psig/1100 F/1100 F built in late 1990s & 2000s 4000 psig/1100 F/1100 F built in the 2000s overseas ** 4500 psig/1150 F/1150 F expected in the 2010 – 2020
Leading Vendors	Boiler OEMs - Alstom, Babcock Power, B&W, Babcock-Hitachi, F-W, IHI, MHI, & Mitsui Babcock	Boiler OEMs - Alstom, Mitsui Babcock, B&W, Babcock-Hitachi, Doosan, & IHI	
Major Trends	Standardized designs to reduce cost & construction time. Fuel flexibility.	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.
Changes to Watch for	More integrated furnace & air quality control systems; further development of low NO_x burners.	Price differential on MMBtu basis between coal & natural gas. Renewed interest related to improved plant efficiency, which reduces SO_2, NO_x, Hg, & CO_2 emissions.	Utilization of Japanese & European technology. Renewed interest related to improved plant efficiency, which reduces SO_2, NO_x, Hg, & CO_2 emissions. Funding could be impacted by emphasis on CO_2 emissions. Concerns over global warming are restricting approval of new coal-fired plants.
Capital Cost Dec 2008 $/KW 750 MW Unit	N/A	2650 (W/O CO_2 Capture)	4435 (With CO_2 Capture) (2025 time frame)
Levelized cost of electricity (LCOE, Dec. 2008 Constant $/MWh)	N/A	66	101 (A) – 86 (B)
Other Characteristics	Integration of boiler and emission controls	Extensive operating experience	Advanced integration of boiler and emission controls
Heat Rate, HHV (Btu/kWh)	9,200 – 9,600	8,900 – 9,300	A) 12640 – With CO_2 Capture, No cost and performance Improvements B) 10340 – With CO_2 Capture, with cost and performance Improvements
Resource Requirements that Impact Technology	Economics & practicality not favorable for low grade coals (coals with HHV less than 6,000 Btu/lb).	Same as Subcritical + increasing price of alloys for pressure parts & FGD absorbers.	Same as Subcritical + cost & development of 1300°F high chrome & nickel alloy pressure parts.

Table 2-1 (continued)
Pulverized Coal – Technology Summary

	Advanced-Subcritical PC	Conventional-Supercritical PC	Advanced (Ultra) Supercritical PC
Market Restructuring & Deregulation	Improving integration of boiler & emission controls at existing units	Life extensions of existing units.	Industrial cogeneration favors combustion turbines.
Key Issues	Upgrading existing units. Competition from CFBC & potential competition from IGCC. Resolution of CO_2 regulations for new plants.	Reducing capital cost. Improving performance, availability, & cycling capability. Upgrading existing units. Resolution of CO_2 regulations for new plants.	Utilizing Japanese & European experience. Potential competition from IGCC. Resolution of CO_2 regulations for new plants.
Key Market Indicators	Higher natural gas prices in late 1990s & early 2000s caused resurgence of coal-fired plant construction. In 2008, concerns over global warming caused cancellation of many new coal-fired projects.	Addition of new units at existing plants. Increasing deployment of larger single wet FGD absorbers.	Concerns over global warming may result in a return to construction of CTCC plants even though natural gas prices are high compared to coal.
Key Business Indicators	Competition from NGCC & CFBC.	Competition from NGCC, CFBC & IGCC.	Global market for purchasing equipment. Willingness of US, Japanese & European OEMs to continue R&D into efficiency improvements with regulatory climate resulting from concerns over global warming.

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.
A) & B) - With CO_2 removal & compression & auxiliary power increases. (A) – Advanced SuperCritical W/O performance improvements; (B) – Advanced SuperCritical With performance improvements.
** One unit in Denmark with steam conditions of 4,200 psig/1080F/1080F/1080F began operation in late 1990s.

3
INTEGRATED COAL GASIFICATION COMBINED CYCLE (IGCC)

3.1 Description

The Integrated Gasification Combined Cycle (IGCC) process is two-stage combustion with cleanup between the stages. The first stage employs the gasifier where partial oxidation of the solid/liquid fuel occurs by limiting the oxidant supply. Oxygen and water or steam reacts with carbon to produce a fuel gas composed mainly of CO and H_2. The second stage uses a gas turbine combustor to complete the combustion thus integrating the combustion turbine combined-cycle (CTCC) technology with various gasification systems. The syngas produced by the gasifier need to be cleaned to remove the particulate, sulfur compounds, and NO_X compounds before it is used in the combustion turbine. It is the integration of the system components that is the most important advantage of IGCC plants.

Various subsystems of an IGCC Plant are:

- Air Separation Unit (for oxygen-blown gasifiers)
- Gasification Plant
- Power Block
- Gas Clean-up System

A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is controlled so that only a relatively small portion of the fuel burns completely. This "partial oxidation" process provides the heat required for the gasification reactions. Rather than burning, most of the carbon containing feedstock is chemically broken apart to produce syngas. Syngas is primarily hydrogen, carbon monoxide, and other gaseous constituents, the composition of which can vary depending upon the conditions in the gasifier and the type of feedstock.

Sulfur impurities in the feedstock are converted to hydrogen sulfide and carbonyl sulfide, from which sulfur is extracted, typically as elemental sulfur or sulfuric acid. Nitrogen oxides are 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, which is then burned in a combustion turbine. Hot air from the combustion turbine can be channeled back to the gasifier or the air separation unit. In addition, exhaust heat from the

combustion turbine and heat recovered from the syngas clean-up cooling system are used to generate the steam for a steam turbine-generator.

Another advantage of gasification-based energy systems relative to conventional combustion is that the carbon dioxide produced by the process is in a concentrated high-pressure gas stream. The partial pressure of carbon dioxide is much higher than that in flue gas. This is especially true for oxygen-blown gasifiers, though air-blown gasifiers also provide a higher partial pressure of carbon dioxide than in ambient-pressure flue gas. This higher pressure makes it easier and less expensive to separate and capture carbon dioxide from syngas than from flue gas. Once the carbon dioxide is captured, it can be sequestered (prevented from escaping to the atmosphere).

The IGCC technology is able to achieve low air emissions because of the following:

- By removing the emission forming constituents from reduced syngas volumes under pressure prior to combustion, IGCC can meet extremely stringent air emission standards.
- Sulfur removal is >99%.
- NO_x emissions are <20ppmv at 15% O_2 in GT exhaust (about 0.07 lb/MMBtu for new IGCC). These levels can probably be lowered with further combustor modifications. SCR can be used, but the economics are not yet established.
- CO emissions are 1–2 ppmv at 15% O_2 (<0.05 lb/MMBtu). Particulate emissions are not detectable.
- Mercury speciation in IGCC has yet to be completely identified. However, at Eastman the use of sulfur impregnated activated carbon beds in the syngas stream at ambient temperatures prior to the sulfur removal process (Rectisol) captures 90–95% of the mercury. The cost should be low.
- Several studies of coal technologies have shown that if CO_2 removal is required by CO_2 emission regulations, removal is much less expensive in IGCC plants from syngas under pressure prior to combustion than from PC plants with post combustion removal at ambient pressures. With CO_2 removal, the cost of electricity is 15–20% lower for IGCC than PC, so that IGCC becomes the preferred coal technology if CO_2 removal is required.

3.1.1 Gasification Technologies

There are three types of gasification technologies. The three types of gasifier processes are:

- Moving-bed
- Fluidized-bed
- Entrained-flow

In addition, gasifiers are either air-blown or oxygen-blown. All of the commercially available entrained-flow gasifiers are oxygen-blown, though Mitsubishi Heavy Industries began testing an air-blown entrained-flow 250 MW IGCC pilot plant in September 2007.

From past R&D work as well as from the demonstration plant operations, the lessons learned from coal IGCC include the following:

- IGCC's very low SO_2, NO_X, and particulate emissions are below recent PC plants permit limits.
- GE E-Gas and Shell gasifiers have been successfully demonstrated at commercial size.
- GE 7 FA gas turbines perform well in IGCC application. All OEMs have now adopted multiple can annular combustors. Newer reference plant offerings are based on the larger, more efficient 7FB gas turbine.
- The high degree of integration used in the European IGCC plants is not recommended for new IGCC plant designs.
- Mercury removal from syngas has been successfully practiced at the Eastman Chemical coal gasification plant for the past 19 years.
- IGCC is currently being commercially used in many plants worldwide based on the gasification of petroleum residuals providing power, steam, and hydrogen.
- Future advances in gas turbine and fuel-cell technologies will improve efficiency and lower cost.
- Existing single-train IGCC coal plants have not yet achieved their yearly availability targets of 85%, although on a quarterly basis the targets have been achieved, creating the expectation that yearly targets will be achieved in mature plants.
- Areas for gasification improvement are carbon conversion (GE Energy), longer refractory life, longer fuel injector tip life, reduced syngas cooler (SGC) fouling, and reduced dew point (downtime) corrosion.

The performance of the coal gasifier in terms of efficiency is affected principally by the quality of the coal. Coal quality has the following impacts:

- Entrained gasifiers perform best with low ash bituminous coals.
- Sub bituminous coals and lignites can be processed, but the oxygen consumption and gasifier cold gas efficiency (CGE) makes their use less economic unless they are low cost (for example, mine mouth). This is particularly true for slurry-fed gasifiers.
- High-ash coals (>20%) are not recommended for entrained slagging gasifiers.
- Low-rank and high-ash coals are more suited to fluid-bed gasifiers. However, the fluid-bed gasification processes need further development.

3.2 Technology Summary

Table 3-1 is a summary of ongoing TAG® update work. It addresses:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends

- Development and commercialization timeline
- Relevant business issues

3.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1, Introduction, the cost for an IGCC unit varies widely depending on such factors as coal type, regional considerations, site-specific conditions, and owner design philosophy. EPRI TAG® presents cost data by six NERC regions, by three coal types and includes generic site specific costs such as substation, cooling water intake structure etc. The cost data presented in Table 3-1 represents the range for the above conditions. In general, IGCC units based on low sulfur bituminous coals found in the northeast United States are lower in capital cost and O&M cost. However, this lower cost is moderated somewhat due to the cold climate of the northeast that warrants certain design conditions for efficient operation.

The major capital, operation and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site-specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Coal quality variations that impact design, storage and delivery (transportation)
4. Owner design and operating philosophy
5. Technology supplier (vendor) design offering

Table 3-1
Technology Summary – Integrated Gasification Combined Cycle

Technologies	Fixed Bed	Fluidized Bed	Entrained Flow	Advanced—Gasification Processes
Leading Vendors	Lurgi	KRW (now KBR), Lurgi, Carbona, Ahlstrom (now Foster Wheeler).	GE Energy, ConocoPhillips, & Shell.	Still in R&D
Major Trends	Pilot plant in Germany in 1936. So. Africa leads after WW II (Sasol). 18 gasifiers by mid-1950s. Late 1970s scaled up over 50%. Sasol produces much of So. Africa motor fuel.	KBR promotes air-blown gasifiers (1) (as opposed to O_2-blown entrained gasifiers).	Standardized designs to reduce cost & construction time. Fuel flexibility.	Higher temperatures in CTs & steam cycle of combined cycle.
Changes to Watch for	There are currently 97 gasifiers at Sasol generating many types of hydrocarbon liquids. British Gas/Lurgi (BGL) is modification/ upgrade to Lurgi. 110 MW BGL IGCC is in Scotland. BGL IGCCs are limited compared to entrained processes.	Carbona & Foster Wheeler sell small Biomass gasifiers. New push associated with small wood mills, farming operations, & other waste Biomass sources for small gasifiers, including small IGCC.	More integration between combustion turbine gas compression & air separation unit (ASU).	Methods to reduce power requirements associated with O_2 production &, if CO_2 emissions become controlled, power for CO_2 removal & compression.
Capital Cost Dec 2008 $/KW 768 (3x256 MW) MW	N/A	N/A	A) 2960 (W/O CO_2 Capture) B) 4083 (W/ CO_2 Capture -2025 time frame).	C) 3317 (W/CO_2 removal and cost and Performance improvements -2025 time frame)
Levelized Cost of Electricity (LCOE, Dec. 2007 Constant $/MWh)	N/A	N/A	A) 71 B) 92 (2025)	C) 78
Other Characteristics	Best suited for coal-to-liquids.	Few commercial installations.	Integration of CT compressor & ASU.	Advanced integration CT, ASU, & emissions controls.
Heat Rate, HHV (Btu/kWh)	N/A	10,500 Btu/kWh (no CO_2 capture).	A) 8980 B) 11000	C) 10,040
Resource Requirements that Impact Technology	Not practical for IGCC.	Increasing price of alloys for pressure parts & vessels. Biomass may become an increasingly more important feedstock.	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.

Table 3-1 (continued)
Technology Summary – Integrated Gasification Combined Cycle

Technologies	Fixed Bed	Fluidized Bed	Entrained Flow	Advanced—Gasification Processes
Key Issues	N/A	Reducing capital cost. Improving performance, availability, & cycling capability.	Reducing capital cost. Improving performance, availability, & cycling capability. Demonstration of viability with low-rank coals. Competition from PC & CFBC.	Reducing capital cost. Improving performance, availability, & cycling capability. Competition from PC & CFBC.
Key Market Indicators	Not practical for IGCC.	Finding niches to increase market share.	Increased escalation of materials & equipment has resulted in significant increases in plant costs & cancellation of a number of projects.	Although IGCC emits less CO_2, association with coal may result in poor public perception.
Key Business Indicators	Not practical for IGCC.	Global growth & market for purchasing equipment. Future price of natural gas & competition from NGCC. Competition from PC & CFBC.	Global growth & market for purchasing equipment. Future price of natural gas & competition from NGCC. Competition from PC & CFBC.	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.

A) No CO_2 capture

B) CO_2 capture and compression and auxiliary power consumption – 2025 time frame

C) CO_2 capture and compression and auxiliary power consumption with cost and performance improvements – 2025 time frame if R&D progresses as planned

(1) Power Systems Development Facility (being developed – not yet marketed) The transport reactor, coal feed & ash removal systems, syngas cooler, syngas cleanup, sensors & automation, recycle, & gas compressor have been successfully demonstrated.

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

4
FLUIDIZED BED COMBUSTION (FBC)

4.1 Description

4.1.1 Circulating Fluidized Bed Combustion Technology

The fluidized bed combustion (FBC) technology has been widely used in the United States, Europe, and Japan since the mid-1980s by utilities and independent power producers/cogeneration, using all ranks of coal, as well as coal wastes, coke, and biomass. Circulating fluid bed combustion (CFBC) is the predominant type of FBC, and units up to 300 MW are currently in operation.

CFBC boilers are established as mature alternatives to PC boilers. The technology is particularly suited to low-grade fuels. SO_2 capture occurs in-situ with limestone fed into the furnace along with the fuel. Inherently low combustion temperatures reduce NO_X formation compared to PC. Fuel flexibility and the ability to burn troublesome fuels including high-ash coal wastes are one of the technology's major advantages. Heat rates of CFBC and PC for the same size, steam conditions, and fuel can be comparable. However, compared to PC plants, CFBC plants tend to be designed for lower grade fuels that increase heat rate.

There have been important strides in improving SO_2 removal with the addition of polishing scrubbers downstream of the air heater and upstream of the fabric filter. These semi-dry scrubbers use solids captured in the fabric filter. These solids are conveyed to the polishing scrubber where they are mixed with water. The flue gas exits the air heater and is passed through the polishing scrubber where additional SO_2 is removed. This process allows the Ca/S ratio to the CFBC furnace to be reduced while still achieving overall SO_2 removal greater than 95%.

4.1.2 Resurgence of Atmospheric CFBC Power Plant Construction (Current Market)

CFBC plant construction was very strong in the 1980s. However, as with PC-fired plants, construction became very sluggish in the 1990s. Environmental concerns and relatively inexpensive natural gas led to a mini-boom of natural gas-fired combustion turbine plants in the last half of the 1990s. In fact, the majority of generating capacity built during this period was either natural gas-fired combined cycle or natural gas-fired simple cycle plants.

As indicated in the PC-fired plant section, starting in about 1999, natural gas prices began to rise at a significant pace. As a result of very high natural gas prices, combustion turbine-based plant construction dropped precipitously in the 2000–2001 timeframe. The growth of the economy and electric consumption in the early 2000s led to renewed construction of coal-fired power plants including atmospheric CFBC plants.

As recently as May 2007, NETL data indicated that 150 coal-fired units would be built by 2030 (CFBC, PC, and IGCC). The data further indicated that about 80 would be built by 2014; and, of these, 23 would be atmospheric CFBC. Even as this list was being compiled in 2007 and early 2008, things began to change very quickly. By the end of 2007, of the 150 coal-fired units identified by NETL in May 2007, 10 had been constructed and 25 were under construction. However, 59 of the units had been cancelled. The flurry of cancellations has been attributed to: 1) considerable concern by activists and the public concerning global warming and related CO_2 emissions and 2) the dramatic rise in the costs of power plants that occurred during 2006 and 2007. A 2008 update of the assessment by NETL indicates that the number of atmospheric CFBC units under construction as 7, near construction as 2, and permitted as 5, for a total of 14 units.

The citizen, activist, and utility commission climate is such that it will be challenging for any coal-fired plants not already under construction to go forward in the near-term unless the designs are altered significantly. It appears likely that alterations will include much higher plant efficiency and/or could include CO_2 removal.

4.1.3 Thermal Performance

The trend toward more efficient atmospheric CFBC units has been to improve their performance in comparison to PC-fired units. In addition to the incentive to improve efficiency there have been efforts to reduce emissions of SO_2, NO_X, mercury, as well as to lower variable operating costs such as costs for fuel and limestone.

Over the last 10 years, one of the significant goals of CFBC OEMs was to increase the size of CFBC boilers. This was motivated by the desire to take advantage of economy of scale from the standpoint of capital cost and plant efficiency. Figure 4-1 provides a curve showing the progression of Subcritical CFBC unit size from 1998 to 2006.

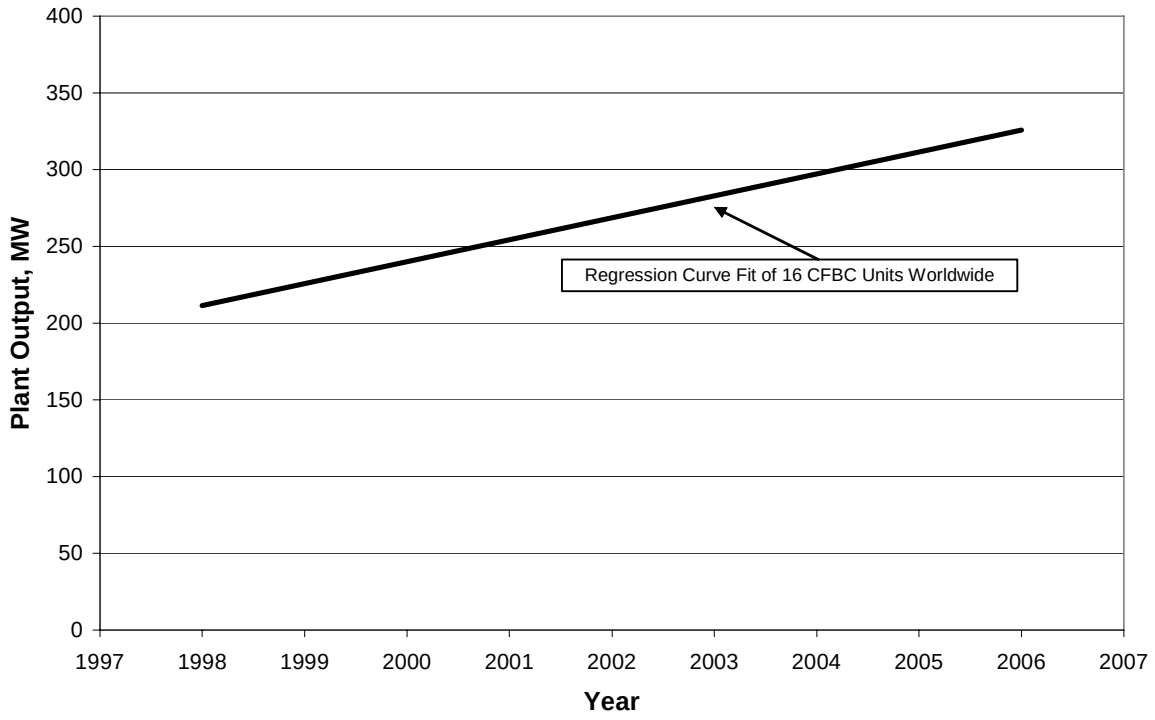


Figure 4-1
Progression of Atmospheric CFBC Unit Size Based on 16 Units Worldwide

At the same time, there has been a push to build supercritical CFBC units. The first supercritical unit is being built in Poland. It is 460 MW and is designed with supercritical steam conditions of 3,990 psig/1040°F/1080°F (27.5 MPa/560°C/580°C). The net plant efficiency is indicated to be 43.3% (LHV) or 41.6% (HHV). The project constructors received Full Notice to Proceed in December 2005. Construction at the site started in February 2006, as of May 2009, the plant had completed initial operating experience and has begun commercial operation.

4.2 Technology Summary

Table 4-1 is a summary of ongoing TAG® update work. It addresses:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

4.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1, Introduction, the cost for a FBC unit varies widely depending on such factors as coal type, regional considerations, site-specific conditions, and owner design philosophy. EPRI TAG® presents cost data by six NERC regions, by three coal types and includes generic site specific costs such as substation and cooling water intake structure. The cost data presented in Table 4-1 represents the range for the above conditions. In general, CFBC units based on low sulfur bituminous coals found in the northeast United States are lower in capital cost and O&M cost. However, this lower cost is moderated somewhat due to the cold climate of the northeast that warrants certain design conditions for efficient operation.

The major capital, operation and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site-specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Coal quality variations that impact design, storage and delivery (transportation)
4. Owner design and operating philosophy
5. Technology supplier (vendor) design offerings

Table 4-1
Technology Summary – Fluidized Bed Combustion

	Conventional Atmospheric Circulating FBC (CFBC)	Advanced Atmospheric CFBC	Supercritical Atmospheric CFBC
Leading Vendors	ALSTOM, F-W, B&W, Kvaerner	ALSTOM, –F-W	
Major Trends	Existing units: co-firing Biomass. Need to retrofit Hg control	More compact/integrated designs. Included flash dryer absorbers (polishing scrubbers). Continuing increase in size of new units	More compact/integrated designs. Continuing increase in size of new units
Changes To Watch For	Price differential on MMBtu basis between coal & natural gas (economics of CFBC plants compared to CT plants). Stricter regulations requiring higher efficiencies for SO_2 & NO_x removal. Stricter regulations require higher Ca/S for SO_2 removal or retrofit of polishing scrubber	More new units with higher temperature steam conditions. Concerns over global warming will probably continue to restrict approval of new CFBC plants	Construction of additional units with super-critical steam conditions. New alloys - higher temperature & pressure. Concerns over global warming will probably continue to restrict approval of new CFBC plants
Capital Cost Dec 2007 $/KW 750 MW (3×250 MW Units)	N/A	2460 (W/O CO_2 Capture)	N/A
Levelized Cost of Electricity (LCOE, Dec. 2007 Constant $/MWh)	N/A	69	N/A
Heat Rate, HHV (Btu/kWh)	10,500 – 12,200	9,600 – 11,700	9,200 – 10,900
Resource Requirements That Impact Technology	Favors waste coal & high reactivity limestone; fuel flexibility allows multi-fuel options. Co-firing of Biomass (all coal-fired units in Britain co-fire up to 6% Biomass) – this lowers net CO_2 emissions [18]	Same as 1st generation plus increasing price of alloys for pressure parts. Co-firing of Biomass (all coal-fired units in Britain co-fire up to 6% Biomass). This lowers effective CO_2 emissions	Same as 1st generation plus increasing price of alloys for pressure parts. Co-firing of Biomass (all coal-fired units in Britain co-fire up to 6% Biomass). This lowers net CO_2 emissions
Market Restructuring & Deregulation	Life extensions of existing units	Construction of CFBC units by deregulated power producers	Construction of supercritical CFBC units by deregulated power producers
Key Issues	Improving performance. Upgrading existing units	Reducing capital cost. Reducing aux. power, improving performance, & availability	Successful operation of first supercritical unit. Demonstrating cycling capability. Competition from PC & potential competition from IGCC
Key Market Indicators	Addition of new units at existing plant sites	Addition of new units at existing plant sites. Increasingly larger single boilers	Higher natural gas prices in late 1990s & early 2000s caused resurgence of coal-fired plant construction. In 2007, concerns over global warming causes cancellation of many new CFBC projects
Key Business Indicators	Competition from NGCC & PC	Competition from NGCC, PC, & IGCC	Competition from NGCC

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

5
COMBUSTION TURBINE COMBINED CYCLE (CTCC)

5.1 Description

Combustion turbine combined cycle units are chosen by utilities for power generation when they desire shorter installation time compared to PC plants, low emissions, and relatively low total plant cost. In addition, combustion turbines, when utilized in a combined cycle, demonstrate some of the highest plant efficiencies currently attainable along with high plant availability. Combustion turbines can also be fired with alternate fuels, but environmental requirements have resulted in most units being fired with natural gas.

A combustion turbine (CT), 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.

A simple cycle CT is one in which the working fluid remains gaseous throughout the cycle, which consists of adiabatic compression, isobaric heating, adiabatic expansion, and isobaric cooling. In some cases, simple cycle CTs are used in conjunction with heat recovery steam generators (HRSGs) to produce steam. In this configuration, all steam produced is used for process purposes such as in a refinery, for enhanced oil recovery, or in a steam-injected gas turbine (STIG) cycle.

The major emissions from CTs are nitrogen oxides (NO_x). NO_x emissions have been controlled by injecting water or steam into the combustor. Several manufacturers offer dry low- NO_x (DLN) combustors commercially, where low levels of NO_x are achieved without having to inject water or steam.

The power output of the combustion turbine is very sensitive to ambient temperature. Maximum power typically drops about 0.4% for each degree Fahrenheit increase in ambient temperature. For example, a CT with an output rating of about 160 MW at 59°F ambient temperature at sea level drops to about 140 MW at 90°F ambient. The reference site conditions (as per ISO standards) for data presented are 59°F, 60% relative humidity, and sea level elevation.

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 of 2350°F. This higher inlet temperature reduces the heat rate by about 10%.

Newer heavy frame machines are also incorporating some of the advances made initially in jet engines, as well some innovations made specifically for power generation. Increases in compressor pressure ratios and improvements in turbine section cooling, materials, and thermal barrier coatings are resulting in improved efficiency by taking advantage of increased turbine inlet temperatures and decreased compressor bleed air. Newer machines are operating at 20 to 30 atm, similar to the aeroderivatives discussed later. In addition, recently announced machines ('G' and 'H' technologies) are incorporating advanced air cooling and steam cooling technologies to allow turbine inlet temperatures above 2600°F, which further increases efficiency. Simple cycle efficiencies in excess of 38% (LHV basis) can be achieved. Most of these advances are applied to higher output engines, although there also is progress in smaller sized machines.

The key features of simple cycle CTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost, and short construction time. These advantages make them attractive for peaking duty applications. Peak duty simple cycle plot arrangements can be designed to allow for later conversion to combined cycle through staged development. Key issues include long-term natural gas availability, transportation, and pricing.

Simple cycle CTs are assumed to be in peak duty operation with annual capacity factors at 10%. Emissions licensing for NO_X is assumed to be at 29 ppmvd, achieved with DLN combustors and without the requirement for selective catalytic reduction (SCR).

In a CT combined cycle (CTCC), the hot exhaust gas from the CT passes through a heat recovery steam generator (HRSG) where it exchanges heat with water, producing steam and cooling the gas to between 200 and 275°F. Initial designs for CTCCs incorporated exhaust gases entering the HRSG at about 1000°F, while more recent designs incorporate exhaust gas at about 1100°F. Typical steam conditions from the HRSG are 700–1500 psig and 900–1000°F. This steam drives a steam turbine generator (STG), which provides the bottoming cycle. Usually about two-thirds of the power is produced from the CTs and one-third from the STG. Advanced CT exhaust temperatures, in most cases, lead to the selection of a reheat STG cycle for a higher bottoming cycle efficiency. Using the more advanced 'G' and 'H' technology combustion turbines firing at 2400 to 2600°F; the combined cycle efficiency can approach 58 to 60%.

Simple cycle combustion turbine and combustion turbine combined cycle (CTCC) power plants are a mature generation technology representing about one-third of the electricity generated in the United States. CTCC units have become larger in size as the technology has advanced. The move toward larger CTCC units has been motivated by capital cost economy-of-scale and improvement in efficiency. The trend to larger size is evidenced by the fact that in 1994 there were 10 CTCC models available in the range of 350 MW–750 MW, whereas in 2008 there are 27 models available in the same size range. Further, in 1994 the largest CTCC unit was 750 MW while in 2008 the largest unit was 1,000 MW.

CTCC units have a much higher efficiency than generation technologies such as PC or CFBC. For 60 Hz CTCC units with outputs of 100 MW to 800 MW, the efficiency ranges from 50% to 60% on LHV basis or 45% to 54% on an HHV basis. This efficiency range is 3 to 12 percentage points better than supercritical PC units. Moreover, the efficiency of CTCC units is 7 to 16 percentage points better than subcritical PC units. This means that CTCC units have a relative efficiency advantage of 30 to 40% compared to PC units. It follows that on a strictly fuel-cost

basis, CTCC units are favored when natural gas prices are no more than 30 to 40% greater than coal prices (on a $/MMBtu basis). However, with natural gas currently at about $3 per MMBtu and coal well under $1.00 per MMBtu, capital cost differences must also be considered. It is estimated that the capital cost for pulverized coal-fired plants is 2-3 times that of the CTCC plant on a per kW basis for plants with similar capacity.

5.2 Technology Summary

Table 5-1 is a summary of ongoing TAG® update work. It addresses:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

Table 5-1
Technology Summary – Combustion Turbine Combined Cycle

	State of the Art Heavy-Duty Combustion Turbines	State of the Art Aeroderivative Combustion Turbines	Advanced - Heavy-duty Combustion Turbines on Natural Gas (NG)
Leading Vendors	• Alstom Power, GE, Siemens Power Generation (SPG), MHI.	GE, Pratt & Whitney, Rolls-Royce	Alstom Power, GE, MHI, SPG
Major Trends	2,400°F plus firing temp. Some aero features. Dry low-NO_x Comb. External cooling of cooling air.	2,550°F firing temperature (LMS100). Industrial cogeneration. Quick delivery of pre-packaged units. Off-site over-hauls Dry low-NO_x Comb.	2,600°F firing temperature. Steam cooling system. Use of ceramics.
Changes to Watch for	Modest upgrades to provide low cost alt to Advanced Turbines. ATS cross-over in materials & coatings.	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).
Capital Cost Dec 2008 $/KW 750MW (3×3×1 7F Units)	880	N/A	902
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	74–89 (@ $8–10/MMBtu Natural gas price)	N/A	67–81 (@ $8–10/MMBtu Natural gas price)
Heat Rate, HHV (Btu/kWh)	CTCC – 7260 Btu/kWh		CTCC – 6320 Btu/kwh (H Class)
Resource Requirements that Impact Technology		Natural gas (NG) supply & price	
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. In December 2007, in Germany, SPG commenced testing of its 340 MW SGT5-8000H in simple cycle; after validation for 18 months, will be integrated to CC at 530 MW output.
Key Market Indicators	Growth in peaking and cycling power generation. Impact on capital cost & plant performance if CO_2 removal is mandated.	Growth in industrial cogeneration. Impact on capital cost & plant performance if CO_2 removal is mandated.	Rise in NG prices may justify investment in more CT R&D. Impact on capital cost & plant performance if CO_2 removal is mandated.
Key Business Indicators	Growth in both merchant plant & traditional utility power generation, especially peaking. Price & availability of NG. Spike in capital cost due to significant increase in recent escalation of equipment & materials.	Growth in industrial competition & deregulation. Spike in capital cost due to significant increase in recent escalation of equipment & materials impacts economics.	Resurgence in merchant plant market? Price & availability of NG. Spike in plant capital cost due to recent significant increases in escalation of equipment & materials impacts economics.

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

5.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1, Introduction, the cost for a CTCC unit varies widely depending on such factors as regional considerations, site-specific conditions, and owner design philosophy. EPRI TAG® presents cost data by six NERC regions, by delivered natural gas price at these regions and includes generic site specific costs such as substation, cooling water intake structure. The cost data presented in Table 5-1 represents the range for the above conditions. In general, CTCC units based on natural gas in the southeast and south central United States are lower in capital cost and O&M cost due to flexibility of design in these regions.

The major capital, operation, and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site-specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Owner design and operating philosophy
4. Technology supplier (vendor) design offerings

6
NUCLEAR

6.1 Description

Nuclear power is a mature technology representing approximately 20% of the electricity generated in the United States and over 15% of the electricity generated in the world. It is well suited for large-scale stationary application, as well as naval vessels such as submarines and ships. Nuclear power is especially attractive to countries with limited access to indigenous fossil fuel supplies, such as Japan and France. The major factors driving interest in nuclear power include projected growth in electricity demand, nuclear power's zero greenhouse emissions profile, increased desire for energy security, and an overall increase in the price of alternative fuels.

Compared to other large-scale central stations, nuclear plants can be more expensive to construct, but less expensive to operate. Higher construction costs are mainly associated with the 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 operating costs of nuclear reactors, the electricity generation costs have historically been more stable than that of coal or natural gas-fired plants. Nuclear plants produce no greenhouse gas emissions and have a lifecycle emissions profile comparable to wind and solar. Nuclear plants generate both high and low level nuclear waste that requires safe storage and disposal. This can be accomplished through various means including interim on and off site storage and permanent geological disposal.

Nuclear power is generated through a fission chain reaction. 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 moderator. The moderator turns fast neutrons into thermal neutrons by reducing the neutron's velocity. The thermal neutrons are then capable of sustaining the fission chain reaction in neighboring fissionable atoms. Less commonly used moderators are heavy water and graphite. Fast neutron reactors do not require a moderator, and they utilize a variety of coolants.

Nuclear fuel typically consists of uranium dioxide enriched to 3–5% (by weight) using the uranium-235 isotope. Natural uranium; mixed oxide (MOX) consisting of both plutonium and enriched uranium oxides; thorium; and other actinides are also used as nuclear fuel. Uranium prices have seen an increase over the last several years, due mostly to renewed interest in construction of nuclear power plants and recent mining production issues associated primarily

with flooding of mines. However, compared to other power plant fuel sources, nuclear fuel costs are quite low and are much less volatile.

Generation I nuclear reactors include plants that were developed in the 1950s and 1960s. These reactors typically used unenriched uranium as the fuel and graphite as the moderator. There are only two such plants still in commercial operation today, (Oldbury and Wylfa), both in the United Kingdom. They are both scheduled for closure within the next 2–3 years.

Generation II (Gen II) nuclear reactors include the current 104 light water reactors operating in the U.S. today. There are 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. This design confines the radioactive components and elements to within the reactor and the primary cooling loop. BWRs allow the water in cooling loop to boil, and this steam is then used to drive the steam turbine. Gen II reactors began to be installed in large numbers during the early 1970s, and comprise the vast majority of reactors in operation today around the world. Gen II reactors generally utilize enriched uranium fuel. The advanced gas-cooled reactor (AGR) utilizes graphite as the moderator and natural uranium for fuel. The CANDU reactor also utilizes natural uranium fuel, and it uses heavy water as its moderator. These reactors include active safety features.

Generation III and III+ nuclear reactors are being constructed and continue to undergo some development. The first was constructed in Japan and has been operating since 1996. They are known as the advanced reactors and are similar to the Gen II reactors with notable economic and safety advancements. The Generation III+ reactors employ passive safety features rather than active ones, with controls using gravity or natural convection. The new designs are licensed by the U.S. NRC for a period of 40 years, however, they have a design life of 60 years and are being considered for operation beyond that. The specific types of Generation III and III+ reactors are:

- The Advanced Boiling Water Reactor (ABWR) by General Electric-Hitachi, and Toshiba is currently licensed in the United States, Japan, and Taiwan. Four units are operating in Japan, with another three under construction in Japan and Taiwan. The ABWR was the first Generation III reactor to operate commercially in 1996 at 1350 MW. The construction phase has been characterized as 39 months from first concrete to first fuel load. ABWRs utilize internal recirculation pumps, resulting in improved reliability and efficiency, reduced radiation dose, and no external piping.
- The Advanced Pressurized Water Reactor (APWR) by Mitsubishi Heavy Industries has a U.S. version known as the U.S.APWR at 1700 MW. The U.S.APWR is specifically designed to comply with U.S. regulations. This design is under review by the NRC for Design Certification in the U.S., while the original APWR design is under review in Japan. A steel neutron reflector surrounds the core; this feature increases the reactivity, allowing for a slightly lower 235U enrichment level.
- The AP1000 from Westinghouse at 1117 MW is a scaled-up version of the earlier AP600 design. It was the first Generation III+ reactor to receive a USNRC Design Certification in the United States, and an amended version is currently under review. One design feature of this plant is that long-term accident mitigation is maintained without operator action or reliance on off-site or on-site ac power. The first U.S. contract agreement since Three Mile

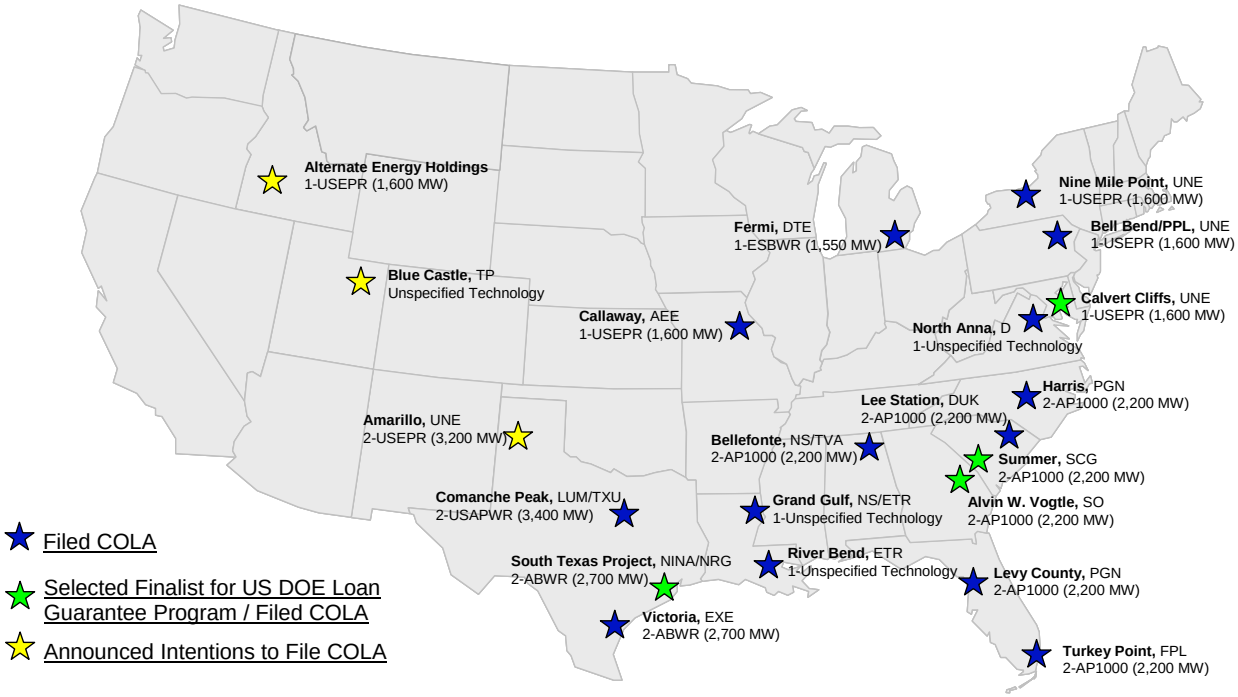
Island was signed in April 2008 by Georgia Power Company for two AP1000 reactors. A construction period of approximately 36 months is targeted.

- The Economic Simplified Boiling Water Reactor (ESBWR) at 1535 MW from General Electric-Hitachi is currently under review for license in the United States. It is considered a Generation III+ reactor. Its design builds on that of the ABWR, with improvements including natural circulation through increased vessel height and decreased active fuel height, further design simplification, and a passive containment cooling system (PCCS). Due to the simple design and reduced building materials, it is estimated that the construction phase for this reactor type would last 36 to 42 months. Also, an operating ESBWR should require less maintenance, thereby reducing the operating costs.
- The EPR by Areva is based on the PWR design. The first reactor of this type is currently under construction in Finland, with another underway in France. In addition, there are two EPR's planned for Taishan, China in the Guangdong province. The U.S. version of this design is known as the U.S. EPR at 1600 MW. The U.S. EPR is currently under review by the Nuclear Regulatory Commission for Design Certification. This reactor contains a large steel "heavy reflector" surrounding the core to reduce fast neutron leakage.

Additionally, several Generation IV (Gen IV) nuclear reactors designs are under various stages of development. It is expected that these designs will not become commercially available until the 2030 timeframe, some toward the middle of the century. In addition to higher thermal efficiencies of many of the Gen IV reactors, one of the major features for these reactors will be their ability to integrate into a closed fuel cycle. That is, the long-lived actinides that are currently being treated as nuclear waste could be used as fuel in many of the Gen IV reactor designs. This may help to reduce spent fuel waste volume and costs, while ensuring the fuel associated with these reactors are resistant to potential nuclear proliferation. It is also expected that these reactors will be capable of efficiently supporting high temperature hydrogen production, high temperature water desalination and other high temperature process heat applications.

Currently, 32 new nuclear units are under consideration at 21 nuclear sites (greenfield and brownfield). To date, 18 Combined Operating License Applications (COLAs) have been filed for 28 new units. Additionally, four sites have been selected for the US DOE's Loan Guarantee Program. These four sites represent seven units, equivalent to 8700 MW. The four sites are:

- SCANA's VC Summer Units 3&4
- Southern Nuclear Operating Companies Vogtle Units 3&4
- Unistar Nuclear Energy's Calvert Cliffs Unit 3
- NINA/NRG's South Texas Project Units 3&4



Source: NRC Expected New Nuclear Power Plant Applications (Feb 4 2009)

Figure 6-1
Expected new nuclear power plant applications

6.2 Technology Summary

Table 6-1 is a summary of ongoing TAG® update work. It addresses:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

6.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1 - Introduction, the cost for a nuclear unit varies widely depending on such factors as regional considerations, site-specific conditions, and owner-specific design and construction philosophies. EPRI TAG® presents cost data by six NERC regions and includes generic site-specific costs such as substation and cooling water intake structure. The cost data presented in Table 6-1 represents the range for the above conditions.

The major capital, operation and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site-specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Owner design and operating philosophy
4. Technology supplier (vendor) design offerings

Table 6-1
Technology Summary – Nuclear

	Commercial Power Reactors (LWR/CANDU/AGR)	Advanced Reactors (ABWR/EPR/ESBWR/ AP1000/etc.)	Fast and/or Thermal Reactors (GFR, LFR, MSR, SFR, SCWR, VHTR)
Leading Vendors	N/A	GE–Hitachi, MHI, Toshiba/Westinghouse, Areva (Framatome), AECL	
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.	Collaboration between and within industry and governments, standardization of designs.
Changes To Watch For	N/A	Development of smaller and medium sized reactors, 10-125MWe.	Additional fuel cycle development – increasing burn up rates to reduce waste volumes and developing new fast reactor fuels to reduce waste toxicity.
Capital Cost Dec 2008 $/KW 1400 MW Unit	N/A	4860 (2015 timeframe) 4127 (2025 timeframe)	Unknown
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	N/A	84 (2015 timeframe) 74 (2025 timeframe	Unknown
Heat Rate, HHV (Btu/kWh)	10,340	10,340	Targets: GFR = 7,100, SCWR = 7,600 MSR = 7,800 - VHTR = 7,600
Resource Requirements That Impact Technology	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favor nuclear.	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favor nuclear, availability of unique materials (especially ultra large reactor forgings).	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favor nuclear, global governance of fuel cycle is not yet decided.
Market Restructuring & Deregulation	Numerous consolidations of plant ownership by nuclear plant fleet operators have occurred in deregulated areas.	OEMs and utilities are partnering to get approval and licensure.	
Key Issues/Concerns	Active safety features, safety and nuclear waste concerns led to poor public opinion.	Lengthy review/approval/construction processes, high capital costs, global competition, potential shortage of workers with nuclear experience	Engineering, materials, and fuel issues require further R&D to ensure reliable performance in a commercial setting. Lengthy review, approval and construction processes, high capital costs.
Key Market Indicators	Operating plants are applying for and receiving license extensions.	Global warming and energy security concerns have positively changed public opinion of nuclear power, any CO2 emissions regulations would favor nuclear.	
Key Business Indicators	Licenses are being extended.	18 COLAs filed for 28 units; currently, interest expressed for a total of 32 new reactors in US. Many new reactors under construction outside U.S.	U.S DOE increasing funding in NGNP Program for FY 2010.

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

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

N/A – Not available; still in R&D stages

7
WIND TURBINE

7.1 Description

Wind is now the fastest growing form of electricity generation in the world. As of the end of 2008, the installed wind generation capacity was 25.2 GW in the United States and 120.8 GW worldwide. As of the end of 2007, worldwide installed wind capacity reached 94 GW with Germany in the lead (22 GW), followed by the United States (16.8 GW), Spain (14.7 GW), and India (7.8 GW). The U.S. market fluctuates from year to year depending on the status of the federal production tax credit (PTC). The federal PTC expired on December 31, 2003 and was extended to December 2005 by tax legislation passed by Congress in September 2004. Since then the PTC has been extended three times to December 2007, 2008 and 2009 by Congress. As a result of the PTC extensions, wind capacity additions have soared in the United States.

The power in the 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 in the wind. For example, a 25% increase in wind speed approximately corresponds to a doubling in the power contained in the wind, which illustrates the importance of accurate resource assessment to a project's success.

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. Quality can vary significantly from site to site. Obviously, some locations are windier than others; and even within a known wind resource area, the wind resource can vary with location and terrain. Evaluating wind resource quality is further complicated by the fact that for a given site, wind resources generally exhibit seasonal, diurnal, and hourly variations. 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.

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. A meteorological tower or mast is erected at one or more locations to continuously measure wind speed, direction, temperature, and sometimes other weather parameters. The measurements are made at multiple elevations above the ground (typically 10, 30, and 60 meters) to allow the wind shear to be estimated. The resulting data are stored onsite by a data logger and periodically downloaded onsite or remotely by modem. Data are analyzed to resolve erroneous values and calculate average wind speeds, directions, and temperatures over annual, seasonal, monthly, and hourly time intervals. The information is often expressed in wind speed frequency distributions and wind roses, which graphically show the relative frequency of wind speed and direction and wind energy.

Wind energy is divided into seven classes based on the wind speed measured at a height of 50 m (164 ft) above grade. The wind power is classified from Class 1 to Class 7 with a classification of one being a low wind speed at less than 5.6 m/s (18.4 ft/s) and seven being wind with a speed greater than 8.8 m/s (28.9 ft/s). As would be expected, strong, frequent winds are the best for generating electricity. Currently, areas with wind speeds of Class 5 and higher are being used with large wind turbines with the future goal of utilizing Class 4 sites.

Over the years, many improvements have been made in wind resource assessment, significantly expanding the size and nature of wind energy resource knowledge. 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 country. The average wind resource potential is the most in the Midwest such as North Dakota, South Dakota, Texas, Kansas, and Montana, as well as parts of Idaho, Wyoming, and Colorado.

Wind speeds increase at greater heights and winds are generally stronger at sea than on land. In addition, the wind is more uniform at sea than on land. Therefore, offshore wind farms are being constructed to take advantage of this weather phenomenon. 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 close 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.

The major wind turbine components are considered to be mature commercial technology. Over the last 20 years, numerous wind turbine design configurations have been proposed, including vertical axis and horizontal axis with upwind and downwind rotors. Rotors have been designed with one, two, and three blades to drive fixed-speed, two-speed, and variable-speed generators. Today, the most common configuration utilizes the “Danish concept”: a three-blade, upwind, horizontal-axis design. Failures of gearboxes, blades, and other components continue to reduce the productivity of wind power plants. To address the gearbox reliability problem, several new technologies are being developed and applied to improve the reliability of the gearbox or eliminate the gearbox entirely.

Wind turbines are designed to function within a wind speed window, which is defined by the “cut-in” and “cut-out” wind speeds. Below the cut-in wind speed, the energy in the wind is too low to be of use; once the wind reaches the cut-in speed, the turbine comes online and power output increases with wind speed up to the speed for which it is rated. The turbine produces its rated output at speeds between the rated wind speed and the cut-out speed—the speed at which the turbine shuts down to prevent mechanical damage.

Power output and stress on mechanical components at high wind speeds are controlled through active or passive yawing to track wind direction and stall or blade pitch regulation to control power output. Stall-regulated airfoils are designed to lose their lift at high wind speeds and are, therefore, self-regulating. Pitch-regulated turbines vary the pitch of the blade to reduce lift and shave off power in high winds. If the wind speed rises to a cut-out value, the blade feathers and the turbine stops turning to avoid excess loads on the rotor and other mechanical components. Pitch-regulated blades also provide a means for optimizing the power output at lower wind speeds. Other power-reducing alternatives that have been employed include pitching only the blade tips, tip brakes, and ailerons.

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. Average turbine size has steadily increased with technological advances such as improved blade manufacturing technology, more sophisticated controls, and power electronics. Globally, the average size of individual wind turbines installed in 2007 was 1.5 MW.

The overall size of wind power plants, or wind farms, have also increased; the average size of wind plants installed in 2007 was 120 MW, roughly double that during the 2004 to 2005 period. The largest wind plant in operation is the 735 MW Horse Hollow plant in Texas, and a number of GW-scale plants are under development.

A wind farm consists of one or more wind turbines arranged in rows or grids, with the longest dimension arranged perpendicular to the prevailing wind direction. Individual turbines are generally separated by five to nine rotor diameters downwind and three to five rotor diameters in the direction perpendicular to the prevailing wind. Wind turbines must be arranged so that the turbines do not shadow each other. As a result, the amount of land that is actually utilized by the wind turbines is only 5–10% of the total land area upon which the units are located. Large wind farms consisting of more than five to 10 machines are typically connected to the transmission grid through a substation. Smaller distributed wind plants with fewer than five to 10 machines are often connected directly to the distribution grid without a substation.

Wind power plants typically operate unattended and are monitored and controlled via a supervisory control and data acquisition (SCADA) system, which communicates with a remote terminal at the utility control facility or other location via a telecommunications link. Under the control of onboard computers, wind turbines automatically start up when the wind speed reaches the cut-in velocity, shut down when the wind speed drops below the cut-in speed or exceeds the top speed, and yaw into the wind as it changes direction. The control system also is designed to shut down the turbine when a mechanical or electrical fault is detected, such as excess speed operation, loss of hydraulic pressure, or excessive vibration. The operational status of each wind turbine in the wind farm is monitored continuously and can be controlled from a remote location to respond to changing operating conditions. Maintenance crews are dispatched only on an as-needed basis when alarms occur and indicate mechanical or electrical problems.

Though there are variations in the system design, a wind turbine can basically be broken into the following subsystems:

1. tower and foundation,
2. rotor (the blades and the center hub that the blades are attached to),
3. drive train, and
4. electrical controls and cabling

A detailed examination of wind generation can be found in Section 3 of the latest Renewable Energy Technology Guide (Product 1019300, May 2009) and in EPRI paper “Wind Power Technology Status and Performance and Cost Estimates - 2008” (Product 1015806).

7.2 Technology Summary

Table 7-1 is a summary of ongoing TAG® update work and address:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

7.3 Current and Projected Technology Performance and Costs

The cost for a Wind unit varies widely depending on the resource type (wind class), regional considerations, site specific conditions, owner design philosophy etc. EPRI TAG® presents cost data by six NERC regions, by different resource types and includes generic site specific costs such as substation etc. The cost data presented in Table 7-1 represents the range for the above conditions.

The major capital, operation and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site specific requirements on design etc
2. Construction techniques and requirements based on code
3. Owner Design and Operating philosophy
4. Technology supplier (vendor) design offering

Table 7-1
Technology Summary – Wind

Technologies	Variable-Speed Wind Turbines	Direct-Drive Wind Turbines	Advanced Wind Turbines
Leading Vendors	General Electric, Enercon, Vestas, NEG Micon	ENercon-Germany	Large wind turbine manufacturers:, GE Energy, Clipper Windpower – U.S., Nordex, Vestas – Denmark, Mitsubishi – Japan, Suzlon – India, Acciona Windpower, ACSA Aerogeneradores Canarios S.A., Ecotècnia, Energias Renovables, S.A., Gamesa, Made – Spain, EU Energy Wind – United Kingdom, Entwicklungsgesell-schaft mbH, Fuhrländer, Multibrid Enercon, Nordex, REpower, Siemens, VENSYS Energiesysteme – Germany, LEITNER – Italy, WinWinD – Finland, Nordic Windpower AB – Sweden, AAER – Canada, Lagerwey Wind – The Netherlands, Goldwind Science & Technology – China.
Major Trends	Larger rotor diameters to operate in lower wind regimes; electronic control of electric output and structural damping.	Steel lattice or tubular tower. No gearbox, reduced weight and cost. Low-speed direct-drive generator. Improved controls and SCADA.	Global installed capacity has increased by a factor of 12 in the past decade due to dramatic cost reductions, renewable energy requirements, and in the U.S. the federal wind production tax credit (PTC).
Changes to Watch for	Continued renewal of production tax credit; extension of credit to investor owned utilities.	Introduction of permanent-magnet generator (PMG) and high-voltage DC (HVDC) systems.	Developing low wind speed turbines to reduce electricity cost from 5 – 6 ¢/kWh to 3 ¢/kWh. Construction of offshore wind farms.
Capital Cost Dec 2008 $/KW 100 (2×50) MW plant	2350 (2015 and 2025)	N/A	N/A
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	99 (2015 @ 35% capacity factor) 82 (2025 @ 42% capacity factor)	N/A	N/A
Heat Rate, HHV (Btu/kWh)	N/A	N/A	N/A
Resource Requirements that Impact Technology	Remote sites with high-average wind speed close to distribution lines.		Wind speed. Land availability (Only 5 – 10% of the land area required is taken up by the wind turbines).
Market Restructuring & Deregulation	N/A	N/A	N/A
Key Issues	Full-span pitch control and power electronics increase cost, Complexity of full-span pitch controls increases maintenance.	Durability of low-speed turbine under fluctuating loads Low-speed generator design, new control system.	N/A
Key Business and Market Indicators	N/A	N/A	Continuation of a tax credit. Increase in state renewable portfolio standards (RPS). Growth in low wind speed applications.

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

8
SOLAR THERMAL AND PHOTOVOLTAIC TECHNOLOGY

8.1 Introduction

There are a variety of solar power technologies that are basically divided into two categories: solar thermal and photovoltaics. Using mirrors, solar thermal technologies concentrate sunlight to a central point to heat up a medium and ultimately produce electricity in a steam cycle or engine. Photovoltaics or solar cells directly convert sunlight into electricity.

8.1.1 U.S. Direct Solar Radiation

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. The sunlight's path through the atmosphere is effectively lengthened or shortened by all of these factors.

As light passes through the atmosphere, some is reflected, some is absorbed, and some is scattered. Because of these losses, the amount of energy that actually reaches the Earth never exceeds about 70% of that present outside our atmosphere. Insolation reaches a solar collector either directly ("direct-normal radiation"), after being scattered ("diffuse radiation"), or after being reflected from the ground. This is an important distinction because all solar thermal designs employ optical concentration and, therefore, can use only direct-normal solar radiation. 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 country. Other locations outside of the U.S. which are well suited for concentrated solar thermal technologies include Southern Africa, the Mediterranean countries (i.e., North Africa, Middle East, and Southern Europe), India, parts of South America, northern Mexico, and Australia.

The economic viability of a site for a concentrating solar plant is dependent on many factors including the amount of direct normal solar radiation, the topography, land availability, and access to transmission lines. Hourly solar resource information is available for many locations throughout the world and can be used to predict the annual performance of concentrating solar systems that track the movement of the sun throughout the day. These performance estimates can be used for rough calculations, but measurements taken over the course of at least one entire year at a potential power plant location are needed to accurately predict the output and, therefore, the energy cost of a solar thermal system.

8.1.2 Environmental Issues

Solar thermal electric technologies are similar to solar PV technologies in being environmentally benign relative to other forms of electricity generation. Large-scale solar thermal plants have footprints in the range of 5–10 acres/MW (2–4 hectares/MW) depending on the number of hours of storage capacity (10 acres/MW corresponds to about 9 hours of thermal energy storage in good solar-resource locales of over 2200 kWh/m^2/yr). 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. Therefore, a more meaningful metric of land use is the area required per annual MWh of output, which is about 2.7-3.0 × 10^{-3} acres/MWh/yr (1.1-1.2 × 10^{-3} hectare/MWh/yr). Note that, although conceptually distinct, these two quantities actually have the same fundamental units of area/power.

Water requirements of trough, CLFR and tower solar thermal generating plants are similar to those of other steam plants of equal nameplate capacity using wet cooling towers. Dry cooling is a viable water conserving alternative, and many new projects will utilize dry cooling, but at a cost of up to 10% lower operating efficiency. . Dish/Stirling engines require no water. In all cases, a minor amount of water is consumed for periodic mirror cleaning.

8.1.3 Potential for Greenhouse Gas Reduction

Solar thermal power plants that are not hybridized with fossil fuel generate no direct emissions of CO_2, methane, or other greenhouse gases. Even when hybridized, the solar-generated portion of the plant's output is emissions free. Consequently, all solar-thermal power plants can provide greenhouse gas emissions reductions when they displace fossil fuel-based generation. In addition, should a CO_2 emissions-reduction mandate be enacted in the future, solar thermal power could become an important component of a CO_2 emissions-reduction strategy and could participate in CO_2 emissions trading.

The CO_2 emissions-reduction potential of a renewable energy power plant is a function of the generation mix of the existing generation system, while the effective CO_2 emissions-reduction cost is a function of the CO_2 emission rate and the average generation costs of the base system and the renewable energy power plant.

8.2 Solar Thermal

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. The concentrated sunlight is then focused onto a receiver that is heated to high temperatures and a gas or liquid inside the receiver transfers the heat to a power generation system.

In general, concentrating solar technologies 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. Another technology, "solar chimney," has been proposed but has not yet demonstrated electricity production at large scale. Because all of these technologies—except the chimneys—involve a heat-driven engine, most can be readily hybridized with fossil fuel and in some cases 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.

Each of the four common solar thermal technologies is at a different stage of development. Currently, parabolic trough is the only technology to have achieved commercial status due to over twenty years of proven operational experience at large scale. 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.

The DOE established the Solar Energy Technologies Program, a cooperative effort with private industry to conduct R&D to advance the development of solar thermal technology for use as an intermediate power source and ultimately a base load power source. One goal of the DOE program is to reduce the cost of electricity from parabolic trough technology to $0.08–$0.10/kWh by 2015 for systems with six hours of thermal energy storage, and to $0.05–$ 0.07/kWh by 2020 for systems with 12–17 hours of storage.

8.2.1 Description of Solar Thermal Technologies

Table 8-1 provides a summary-level comparison of the four types of solar concentrating technologies. The remainder of the solar thermal part of this section will provide discussion on the technical characteristics and costs of these technologies.

Table 8-1
Concentrating Solar Technology Comparison

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

Parabolic trough systems use banks of trough-shaped mirrors with a parabolic cross-section to focus sunlight onto highly absorbing 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 turbine generator to produce electricity. Nine trough plants, built in 1984 to 1990, are generating 354 MW in southern California. These 14-to 80-MW systems are hybridized to derive up to 25% of their output from natural-gas firing and provide dispatchable power independent of the solar energy available. In addition, a 1-MW trough system, commissioned in 2006, is operating in Arizona, a 64-MW trough facility in Nevada became operational in 2007, and the first of several Spanish 50-MW trough plants was completed in late 2008. The Spanish plants are especially notable because several will include over seven hours of molten-salt thermal energy storage. Arizona Public Service has announced plans for 280-MW and 290-MW trough projects with six hours of molten salt storage. Close to 3000 MW of trough projects are planned in the U.S. and another 1000 MW internationally.

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. Stirling Energy Systems (SES), which is co-developing a 25-kW dish Stirling design with Sandia National Laboratories signed separate PPAs in 2005 with Southern California Edison and San Diego Gas & Electric for upward of 1,750 MW. More recently in mid-2009, SES signed a 27 MW contract with CPS Energy for a project in West Texas, and the company announced plans to develop up to 500 MW for the County of Riverside in California.

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. The first central receiver in the United States, Solar One, was installed in southern California and operated in the mid-1980s. It used water as the HTF and generated steam directly to power a 10-MW steam turbine. In 1992, a consortium of U.S. utilities, DOE, and EPRI formed to retrofit Solar One and demonstrate a system, aptly named Solar Two, which incorporated molten salt as the HTF and energy storage medium. In this system, molten salt was pumped from a "cold" tank and cycled through the receiver, where it was heated and returned to a "hot" tank. The hot salt could then be used to generate electricity when needed. Current designs allow storage times ranging from three to 13 hours. Such thermal storage capability makes central receivers (and troughs, when so equipped) the most flexible of solar technologies, promising dispatchable power with high load factors. Solar Two operated from April 1996 to April 1999. The EU's first two commercial central receiver projects were constructed by Abengoa Solar in Spain; 11-MW PS10 became operational in March 2007, and 20-MW PS20 in April 2009. Both are direct steam systems with less than an hour of storage capacity. Meanwhile, over 3000 MW of new U.S. and EU power tower projects are being proposed for construction over the next two to seven years.

There are two notable start-up companies that are currently developing direct steam central receiver technologies. BrightSource, based in Israel with offices in Oakland, CA, has developed a 100 and 200-MW plant design that operates under superheated steam conditions at 1022°F (550°C). They signed PPAs with PG&E for 1310 MW and Southern California Edison for 1300 MW. Another company, eSolar, has signed agreements for 245-MW with Southern California Edison, 92-MW with PG&E, and 150-MW with El Paso Electric. In addition the company signed an exclusive license agreement with the ACME Group to develop up to 1000 MW of projects in India over the next 10 years. eSolar uses a distributed tower approach. Each 46-MW system has 16 towers that provide steam to a single power block.

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 onto receiver tubes located above the collector field. It has some similarities to central receiver technology as well, in that its reflectors are separately mounted from a stationary receiver. The leading manufacturer, Ausra, commissioned a 5 MW demonstration plant in California in late-2008. The company has a contract with PG&E to develop a 177-MW project, also in California.

Long-term cost projections for trough technology are higher than those for power towers and dish/engine systems due in large part to the lower solar concentration involved, 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 are likely to 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.

8.3 Photovoltaics

With growing environmental concerns and the emerging green-power market, solar photovoltaic (PV) appears to be entering a new era in which it will play an increasingly important role in meeting the world's energy needs. Globally, installed PV capacity now exceeds 13,300 MW, and domestic installed capacity exceeds 1,250 MW (distributed PV, non-grid connected PV and utility scale PV). Germany is the world leader with approximately 5,400 MW, followed by Spain with 3,300 MW, and Japan with 1,900 MW. Globally, 1,900 large scale PV plants (i.e. >200 kW) account for 3,000 MW of globally installed capacity. 2008 witnessed a tripling of globally installed utility-scale PV generation. Spain is the world leader in both new (1,900 MW) as well as total (2,300 MW) installed capacity. Last year, the United States added 342 MW of such generation.[*†]

Numerous utility-scale PV projects have been announced so far in the United States this year. From small university-based projects such as the 2.1 MW system to be built at the University of Maryland Eastern Shore to larger 50-150 MW power contracts between utilities such as Southern California Edison (SCE) and Sempra Generation.

Relatively small-scale distributed generation at the residential, commercial, industrial, institutional, business-park, and subdivision scales are by far the dominant current types. Furthermore, new PV technologies and policies that allow and even encourage (through rebates, subsidies, feed-in tariffs and tax incentives) distributed generators to interconnect to the grid are making small-scale on-site generation increasingly competitive, practical, and attractive. For a growing number of applications, straightforward economics favor PV when compared to the projected cost of grid power over a PV system's lifetime. For example, building-integrated PV (BIPV) strengthens the economic argument by incorporating PV into building components such as roofs, windows, or facades that would be necessary in any case and represent a significant portion of a structure's initial cost. However, although large-scale bulk-power PV (>50MW) facilities remain uncompetitive with other intermediate and peaking supply technologies, there has been a growing trend in some markets toward new PV projects being developed in the 10 MW and larger capacity range

8.3.1 Description of PV Technologies

A photovoltaic (PV) or solar cell is made of semiconducting material so that when the sunlight hits the cell the electrons flow through the material and produce electricity. Thus, there are no moving parts required to generate electricity. Typically, about 40 solar cells are combined to form a module. The module is a sealed package primarily consisting of a transparent front material, the interconnected PV cells, and a back cover. Modules can be characterized as flat

[*] REN21. 2009. *Renewables Global Status Report: 2009 Update (*Paris:REN21 Secretariat).
[†] Pvresources.com, Denis Lenardic

plate or concentrator systems. About 10 modules make up a flat plate PV array. Arrays can be mounted at a fixed angle facing the sun or mounted on a tracking device. Concentrator systems are typically the only systems with tracking devices. It takes about 10-20 PV arrays to provide enough electricity for a typical household. For large utility applications hundreds of PV arrays are connected together. Other than the PV module, additional system components include support structures, inverters, a solar tracker if required, wiring and transmission, and land.

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 actual amount of power produced will depend on several factors including the sunlight's intensity (W/m^2) and the operating temperature of the module. From the PV array to the busbar electricity, losses are typically 20% of the initial amount produced. Module performance at higher operating temperatures, wiring losses, DC to AC conversion, and power conditioning all contribute to the 20% loss.

The majority of currently produced cells use wafer-based crystalline silicon technology, which is fairly well understood. For these cells, the silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. However, technology is moving toward thin films that use $1/20^{th}$ to $1/100^{th}$ of the material compared to the crystalline silicon modules. Typically, thin film cells are made using vacuum deposition. As of 2008, the thin-film PV sector exceeded 11% of market share.

Today's prevailing cell technologies are based on a single junction, or interface, which can use only a 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 wave length that it is designed to most efficiently convert.

Not all of the sunlight that hits the solar cell is converted to electricity. Much of the sun's energy is reflected or absorbed by the material that makes up the solar cell. The efficiency of a solar cell is defined as the amount of absorbed light that is converted to electrical energy. The first solar cells, built in the 1950s, had efficiencies of less than 4%. Currently available commercial modules for first generation wafer-based crystalline silicon technology are in the 10-15% range. Today's second generation thin film technologies have slightly lower efficiencies. However, it costs less to manufacture thin film cells than wafer-based crystalline silicon. Additionally, as the manufacturing of thin films advances, the efficiency is expected to increase.

In addition to fixed arrays, PV systems can have a tracking system, although the majority of them with the exception of concentrating systems are fixed. A single access tracking system will rotate east to west with the sun. A dual access tracking system will rotate east to west as well as north to south to accommodate for the seasonal variation in the orientation of the sun. These systems utilize the sunlight more efficiently.

There are two principal types of PV array: flat-plate and concentrator. Concentrator designs use lenses or mirrors to increase the amount of sunlight that reaches the active PV device. However, concentrator designs having more than a few-fold sunlight concentration must use precise, dual axis tracking to always be perpendicular to the sun's rays, because they can only concentrate the direct-normal insolation. Because flat-plate arrays can use both direct and diffuse sunlight, they can be mounted in a fixed orientation but they can also benefit from either one-axis (east-west) or two-axis tracking. An array mounted on a properly functioning one-axis tracker receives

about 20% more solar radiation annually than it would on a fixed-tilt mount, while an array on a two-axis tracker would capture approximately 30% more.

PV system costs have continually decreased—from about $0.40/kWh in 1990 to about $0.20-0.25/kWh by the early 2000 timeframe. The price of power from today's grid-connected systems is roughly in the $0.15-0.30/kWh range. The DOE goal is to reduce the cost of electricity to $0.09-0.18/kWh by 2010. The cost of the PV module is about half of the total system cost, thus modules are a large cost driver. 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. They have already become more efficient and more reliable than the inverters produced in the 1980s and 1990s. Furthermore, the design and installation costs of inverters are expected to decrease as the number of installations increase.

8.4 Technology Summary

Table 8-2 is a summary of ongoing TAG® update work that addresses:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

Table 8-2
Technology Summary – Solar Thermal

	Parabolic Trough	Dish/Engine	Power Tower	CLFR
Leading Vendors	Mirror and solar collector manufacturers (Abengoa Solar, Acciona, SkyFuel, Solar Millenium, Solel, Torresol Energy).	Infina, Stirling Energy Systems, Wizard Power.	Abengoa Solar, BrightSource Energy, eSolar, SolarReserve, Torresol Energy	Ausra, Novatec Biosol
Major Trends	• Hybrid applications • Thermal storage • Larger plant sizes • Higher temperature working fluids	• Large demonstration projects with California utilities • New materials and techniques to reduce manufacturing and O&M costs	• Potentially large projects in the U.S., and Europe • Thermal storage to allow dispatchable solar power	• 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	• Grid connected utility applications • Advances in thermal storage • Higher operating temperatures	• Higher temperature steam generation • Advanced steam storage technology
Capital Cost Dec 2008 $/kW 150 MW Unit	4851-6300	N/A	N/A	N/A
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	225-290	N/A	N/A	N/A
Efficiency (solar to electric)	13.5%	16-30%	8-22%	N/A
Resource Requirements that Impact Technology	Magnitude of direct normal solar radiation. Water availability can be a significant issue in arid climates.	Magnitude of direct normal solar radiation.	Same as parabolic trough	Same as parabolic trough
Market Restructuring & Deregulation	N/A	N/A	N/A	N/A
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 thermocline storage tanks	• Engine availability • O&M costs • Cycling impacts	• Scale up • High temperature operation • Cost reduction	• Low temperature thermal energy storage • Sufficient cost reduction to offset lower efficiency
Key Business and Market Indicators	Increase in state renewable portfolio standards (RPS). Commercial applications.			

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

N/A – Not Available

Table 8-3
Technology Summary – Solar Photovoltaic

Leading Vendors	BP Solar, Shell Solar, GE Energy, United Solar Ovonics, First Solar LLC, SunPower Corp.
Major Trends	• Feed-in Tariff incentivizing small to medium scale (< 10 MW) installation • Increase in state renewable portfolio standard (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-multiple junctions and band-gap engineering.
Capital Cost Dec 2008 $/kW	7,981
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	456 (@ 26% capacity factor)
Efficiency (solar to electric)	10%
Resource Requirements that Impact Technology	Insolation
Market Restructuring & Deregulation	- PPA with utilities as they strive to meet RPS
Key Issues	• Established goal: achieving 15% efficiency at cost of $100/m^2

For other assumptions see Tables 1-6 and 1-7. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

N/A – Not Available

9
BIOMASS

9.1 Description

Biomass is typically defined as carbonaceous materials derived from plants. This would include agricultural wastes (straw and rice hulls), as well as demolition and forestry wastes (for example, bark and wood chips) and municipal sludges. Biomass by its nature is renewable. Agriculture and forestry residues, and in particular residues from timber mills and paper mills, are the most common Biomass resources used for generating electricity. Power from Biomass is a proven commercial electricity generation option in the United States. With over 11,000 MW of installed capacity, Biomass is the second largest source of non-hydroelectric renewable power generation behind Wind energy. The majority of electricity production from Biomass is used as base load power with or without co-generation in the existing system fleet.

There are three primary classes of Biomass-to-thermal energy systems: direct Biomass fired, co-fired with coal, and gasification of Biomass into synthesis gas (syngas).

Most of today's Biomass power plants are direct-fired systems that are similar to many coal-fired power plants. For electric power generation, direct and co-fired systems burn fuel in boilers for generating steam. Proper quality Biomass also can be used directly in a combustion turbine with an externally burning combustion chamber. In a gasification system, Biomass is processed in a gasifier, which in turn generates low-Btu gas (80 to 120 Btu/scft), generally known as syngas. For electric power generation, syngas can be burned either in a boiler for generating steam or can be burned directly in a combustion turbine.

9.1.1 Stoker Grate Technology

Stoker grate boilers using Biomass were developed in the 1920–30s. Stoker grate technology is well proven in the Biomass power generation industry and is commercially available. Stoker grate technology is effective in burning solid fuels that contain fuel particles of sufficient size that they must rest on a grate to burn as well as finely sized particles. Solid fuel is introduced into the furnace using pneumatic or mechanical spreaders, which "stokes" (feeds) the furnace. If the stoker feeds fuel into the furnace by flinging it mechanically or pneumatically over the top of the grate, the stoker is referred to as a spreader stoker. Spreader stoker technology allows for the finely sized particles of the fuel to burn in suspension while the larger solid fuel particles fall on the grate where they burn to completion. Spreader stokers with oscillating, pulsating, or traveling grates have been widely used for Biomass power plants because many of the designed systems have the ability to burn a wide variety of solid fuels simultaneously. Furthermore, they respond more rapidly to load changes and operate more efficiently with low excess air than cross-feed

and underfeed units. Typically, the spreader stoker feed system is more efficient than cross-feed and underfeed stoker systems.

To meet NOX emission standards, stoker grate boiler systems typically include staged combustion systems and accurate combustion control. Combustion is carried out at about 40% excess air, where overfire air accounts for about half the total. Typically, three fans provide the necessary combustion control: one for under-grate combustion air, one for overfire air, and one for pneumatic fuel distributors. Modern stoker boilers also include selective non-catalytic reduction (SNCR) systems to reduce NOX up to a maximum reduction of 50%.

9.1.2 Fluidized Bed Technology

Fluidized bed combustion (FBC) systems have been commercially available for over 20 years in the United States and for longer abroad. Biomass fuels have been successfully fired on many of these units. FBC systems operate on the fluidization process, which begins with a bed of solid granular particles, such as sand or limestone, suspended by an upward flow of air or gas. As the velocity of the gas stream is increased, the individual particles begin to be suspended. At this point, the minimum fluidizing velocity is achieved. As the air or gas flow is increased, the bed material becomes highly agitated and begins to flow and mix freely. Bubbles, similar to those in briskly boiling fluid, pass through the bed and the surface of the solids is diffused and no longer well defined. The bed material is said to be “fluidized” because it has the appearance and some of the properties of a boiling fluid.

In the FBC system combustion chamber, the fuel and bed material are kept in suspension and circulation by the upward current of air and flue gas. The air is distributed uniformly into the bed via a perforated grid plate or a system of nozzles. To initiate combustion in the fluidized material, the bed temperature is elevated by using a startup fuel such as gas or oil to a temperature capable of supporting combustion of the primary fuel.

In Biomass units during operation, Biomass fuel and the inert bed material are continuously fed into the unit. The bed consists primarily of fuel ash and inert bed material, such as sand. Unburned fuel will typically make up less than one percent of the bed. Bed material becomes an isothermal reactor with heat transfer from the bed material to the boiler tube surface and to fresh fuel and air. Turbulent mixing of air and fuel at temperatures above the ignition point of the fuel causes combustion to take place without the need for conventional burners. The unique features of fluidized bed boilers include:

- improved mixing and interaction of fuel and combustion air,
- longer fuel retention time in the combustion zone,
- uniform combustion temperature, and
- lower combustion temperature, which reduces NO_x production.

There are two major types of fluidized-bed combustion (FBC) units. These are bubbling fluidized bed combustion (BFBC) and circulating fluidized-bed combustion (CFBC). The bubbling fluidized bed operates with low-combustion bed velocities (4–12 ft/sec), which in-turn, reduces the flue gas entrainment of fuel and ash particles. Bubbling fluidized bed

systems are less complicated compared to the circulating bed design and are generally used when firing consistent fuels with minimum load variations.

The circulating fluidized bed is designed for higher-combustion bed velocities (10–30 ft/sec) that entrain fuel and ash particles, which, in-turn, requires recirculation of entrained materials (ash and unburned fuel) back to the bed. Recirculation of ash and unburned fuel back to the fluidized bed is used to complete combustion of unburned fuel and to control the fluidized bed temperature. Circulating fluidized bed systems are generally more complicated compared to the bubbling bed design but have greater flexibility for load control and fuel variations.

9.1.3 Fuel Drying

A dryer's function is to make fuel easier to feed, easier to burn, and to allow production of more usable heat. Using dry fuel increases overall thermal efficiency of a boiler since it is not necessary to waste energy vaporizing moisture in the fuel. Fuel also becomes easier to size and feed as moisture is removed. It is generally agreed that drying should be considered in the design of boilers whenever the fuel total moisture exceeds 55%. Some information suggests that there is an optimum moisture level, possibly around 35%, which gives the best balance among dryer cost, plant performance, system efficiency, and problems associated with handling dry fuels, such as dusting and dust explosions. Some modern boiler designs incorporate fuel drying as part of the boiler design to reduce plant cost. This is more cost-effective than external drying.

9.2 Technology Summary

Table 9-1 is a summary of ongoing TAG® update work and address:

- Technology development status (key developers and pilot/demo activities)
- Major technical issues and future development direction/trends
- Development and commercialization timeline
- Relevant business issues

Table 9-1
Technology Summary – Biomass

	Biomass Power Generation System
Leading Vendors	Foster Wheeler, Babcock & Wilcox, Kvaerner, Detroit Stoker, Babcock Power, McBurney, EPI
Major Trends	Small to mid size units – Stoker, Mid to large size units – CFB, Trend towards, co-firing with coal. Combined heat & power, Co-generation
Changes to Watch for	More and more utilities exploiting Biomass potential. Europe installing units larger than United States. Efficiency improvement
Capital Cost Dec. 2008 $/KW 75 MW Unit	3580
Levelized Cost of Electricity (LCOE, Dec. 2008 Constant $/MWh)	90 (based on $2.22/MMBtu fuel cost)
Other Characteristics	
Heat Rate, HHV Btu/kWh	12200 Btu/kwh
Resource Requirements that Impact Technology	None significant; mature technology
Market Restructuring & Deregulation	Increased emphasis on bio-power
Key Issues	Reduced costs and fuel availability. Cost can be reduced by mass application and economy of scale
Key Business Indicators	Price of natural gas, stricter emission limits

For other assumptions see Table 1-4 and 1-5. For technology uncertainty and cost uncertainty, please see Section 1, Introduction.

9.3 Current and Projected Technology Performance and Costs

As mentioned in Section 1, Introduction, the cost for a Biomass unit varies widely depending on regional considerations, site specific conditions, owner design philosophy etc. EPRI TAG® presents cost data by six NERC regions, by two different technology types and includes generic site specific costs such as substation, cooling water intake structure etc. The cost data presented in Table 9-1 represents the range for the above conditions.

The major capital, operation and maintenance cost influencers for a given site are:

1. Site Location—Regional labor cost differences, labor productivity, climate requirements on design, site specific requirements on design, etc
2. Construction techniques and requirements based on code
3. Owner Design and Operating philosophy
4. Technology supplier (vendor) design offering

10
IMPLICATIONS OF CO_2 EMISSIONS COSTS

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. Combining these additional emissions-related costs with overall levelized electricity cost estimates based on the Technical Assessment Guide (TAG) data and methodologies described in this report, sensitivity curves showing levelized costs of electricity as a function of potential CO_2 emissions allowance costs can be developed. 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. 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.

ELECTRIC POWER RESEARCH INSTITUTE

Generation Technology Options in a Carbon-Constrained World

Prepared by the
Energy Technology Assessment Center

Revised October 2009
(Source: EPRI Report 1019539)

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.

Levelized Cost of Electricity Analysis

Analytical Basis

- Utilize EPRI Technical Assessment Guide (TAG®) capital cost data and methodologies to calculate levelized costs of electricity (LCOEs) in constant 2008 $.
  - Incorporate key assumptions needed for calculations – capital cost, fuel cost, annual and fixed 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 2010–2015.
- Estimate LCOEs for 2020–2025 based on expected technology-driven improvements in performance and reductions in capital cost.

Levelized Cost of Electricity Analysis

Analytical Basis

- The weighted cost of capital on a constant dollar basis, after tax, is 5.9%, and a 30 year plant life with 15 year accelerated depreciation was used.
- Mercury, SO_X/H_2S and NO_X removal are included in PC and IGCC Technologies. NO_X removal is included in CT/CC Technology.
- Methodology incorporates technology and cost uncertainties in major components of technology based on the level of maturity of components.
- All near term (2015) capital costs reflect 90th percentile confidence level at +30% to +50% uncertainty range for various components of the technologies. This incorporates the current material and labor cost escalation.
- Longer term (2025) capital costs reflect 50th percentile confidence level.

Levelized Cost of Electricity Analysis

Capital Cost Estimating Approach

- Costs are to be reported in reference year (December 2008) 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

Levelized Cost of Electricity Analysis

Cost Basis

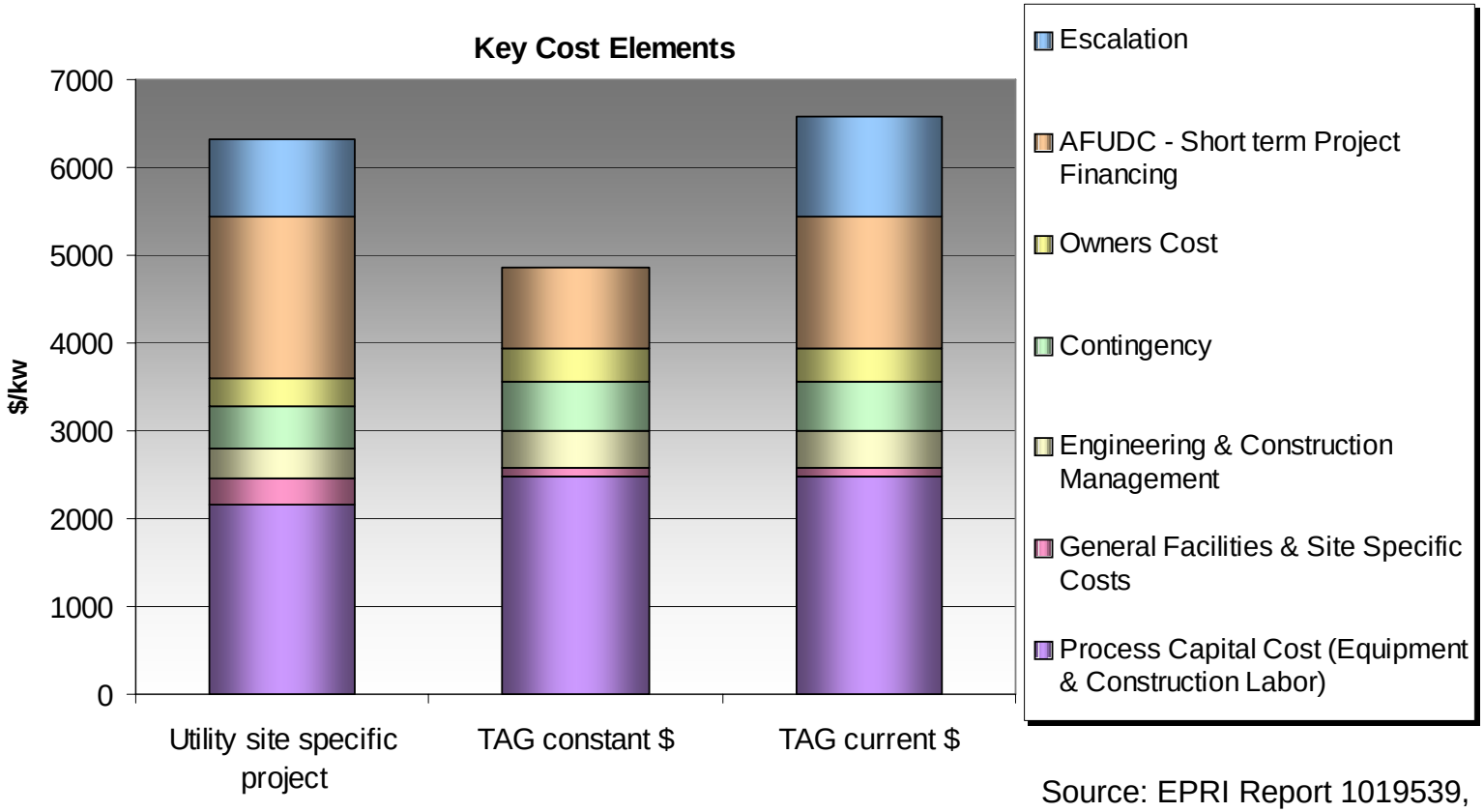
- Total Plant Cost (TPC):
  - All process and support facilities; fuel handling and storage; water intake structure and wastewater treatment; offices, maintenance shops, and warehouses; step-up transformer and transmission tie-in
  - Sometimes referred to as Engineering, Procurement, and Construction Cost (EPC), or Overnight Capital Cost
- Owners 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

Levelized Cost of Electricity Analysis

Capital Cost Estimate Summary

- Total Capital Requirement (TCR) = TPC + Owner's Costs + Project Specific Costs
  - TCR also known as "All-In" Costs
- Total Capital Requirement (TCR) is typically 16–19% higher than Total Plant Cost (TPC):
  - Typical EPRI Owner's Costs add about 5–7% to TPC
  - Interest during construction adds another 11–12% to TPC
- The adder for project-specific costs varies widely:
  - Depends on project and site-specific requirements
  - 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

Estimate in Constant $ and Current $ are Very Different Example: New Nuclear Power Plant



Comparison of Constant vs. Current $

Source: EPRI Report 1019539, Section 1.8.3

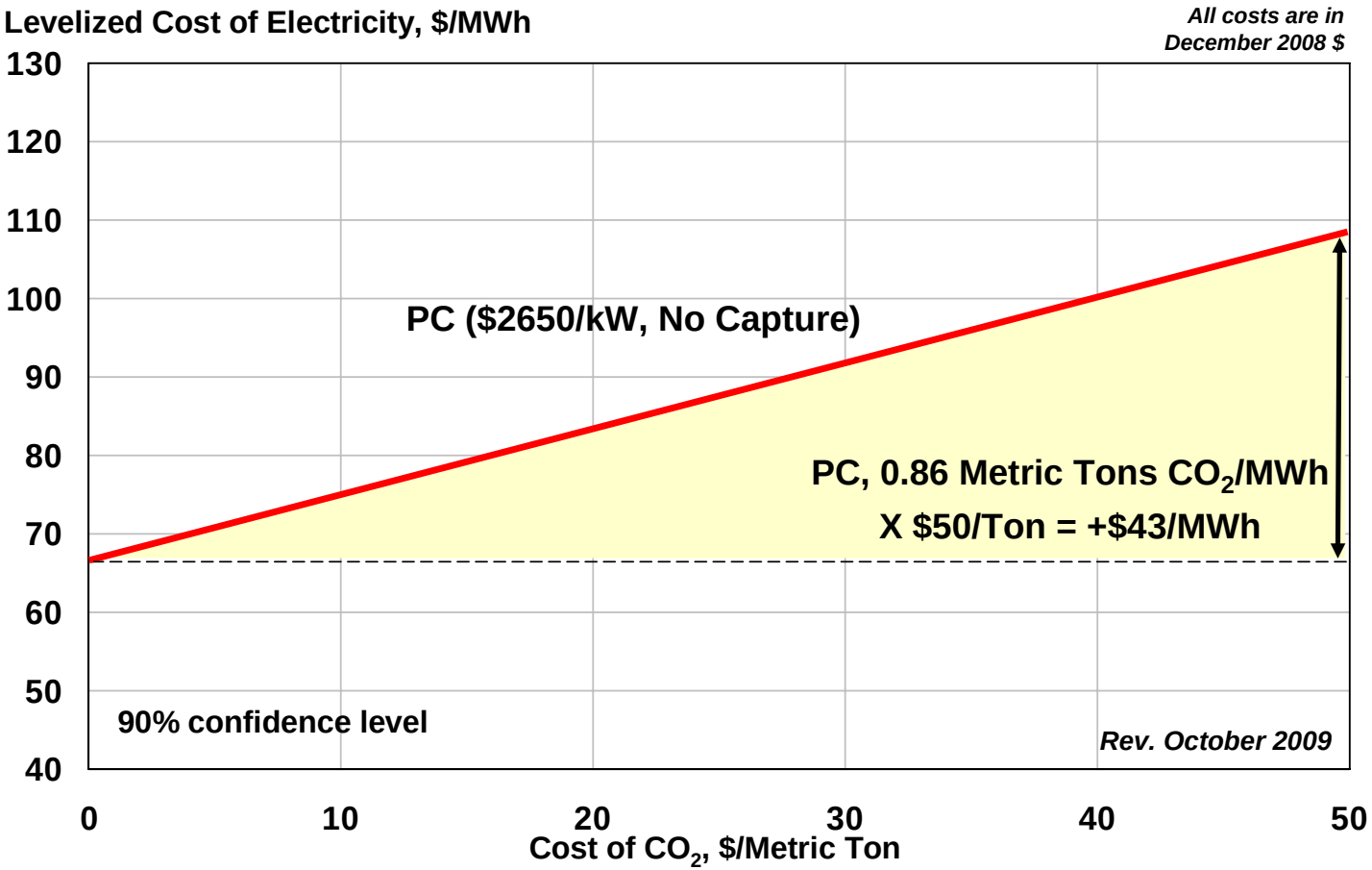
Levelized Cost of Electricity Analysis

Technology Assumptions

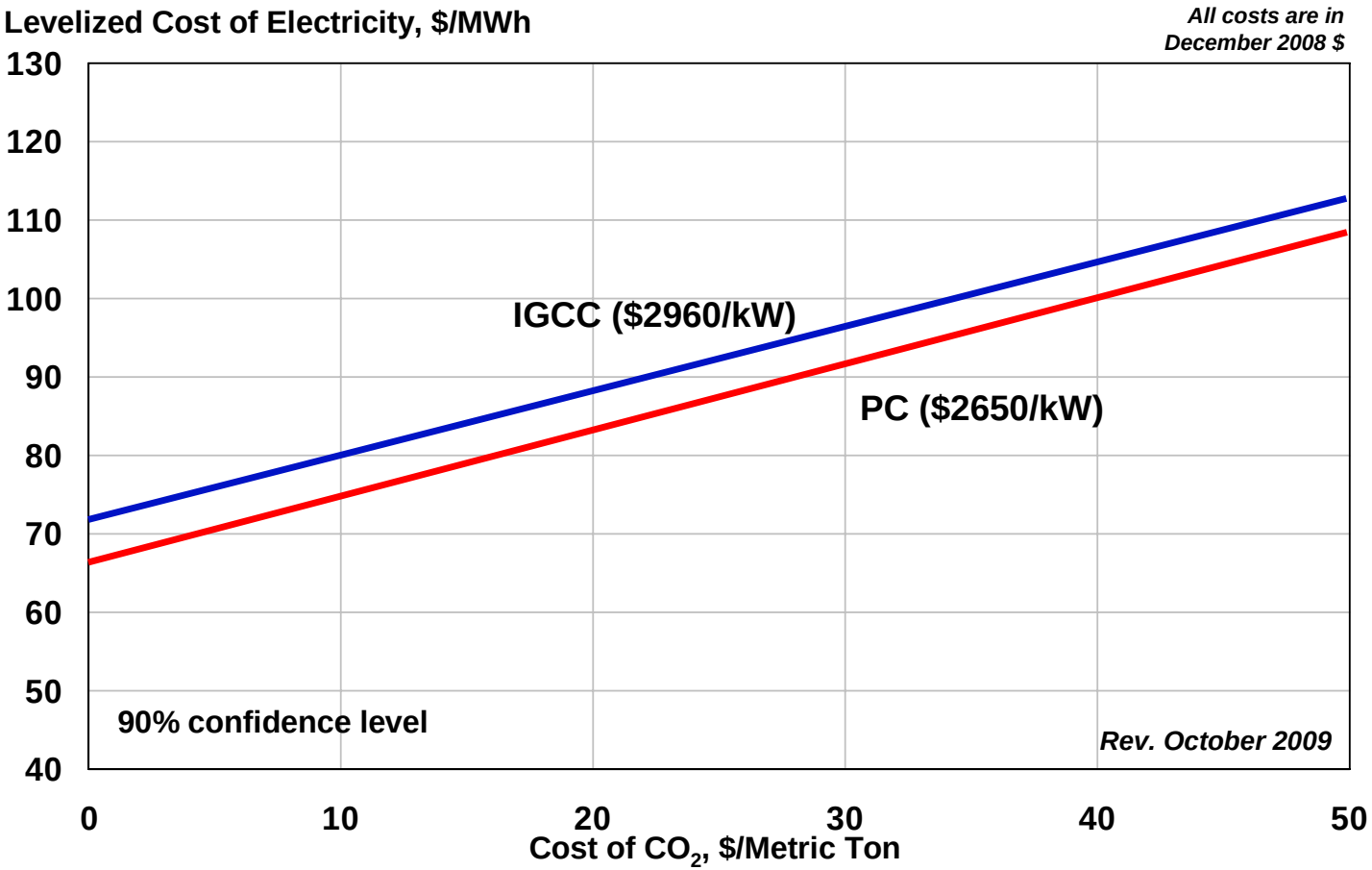
- Near Term – 2010 to 2015
  - Modest extrapolation of today's technology.
  - Based on foreseeable technology development.
- Longer term – 2020 to 2025
  - Assume that established R&D objectives are achieved, and technology development is successful.
  - Estimated reductions in costs are based on assessment of potential technology improvements. Examples: new materials and designs, new gas turbines, chemical processes, and membrane contactors, and a wide range of other technologies.

Near-Term: 2015

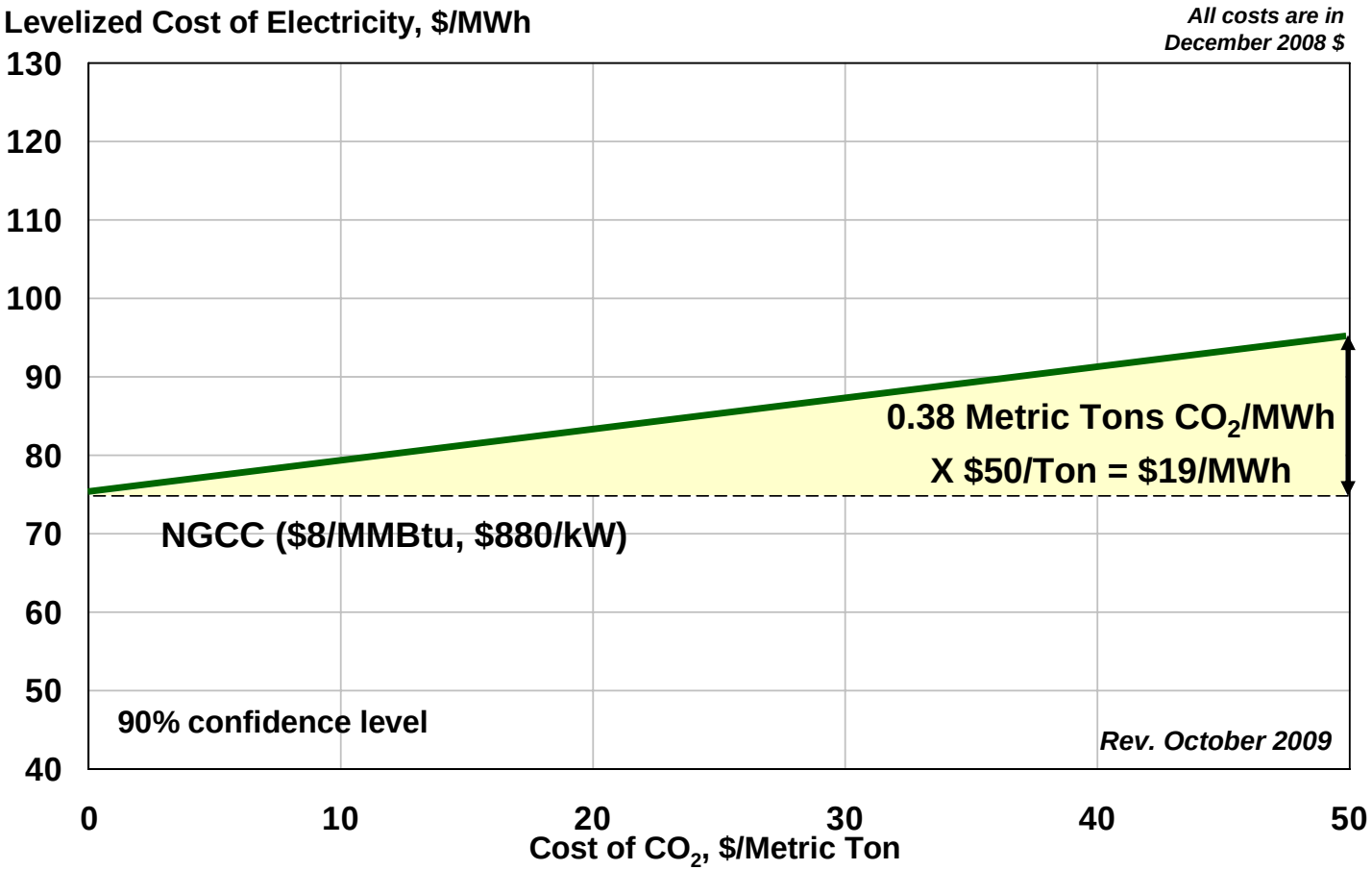
Pulverized Coal Combustion – 2015



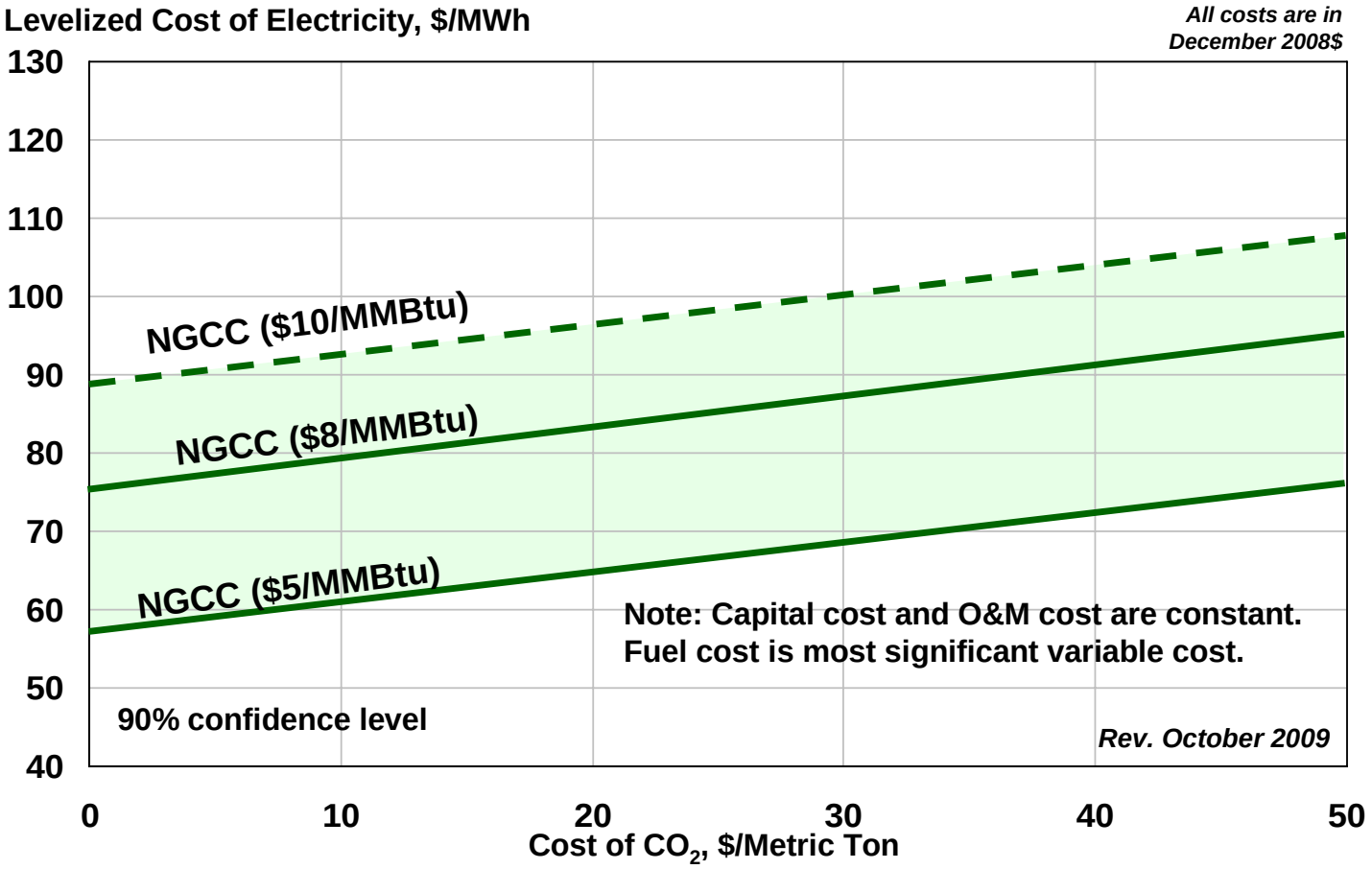
Coal Combustion and Gasification Comparison – 2015



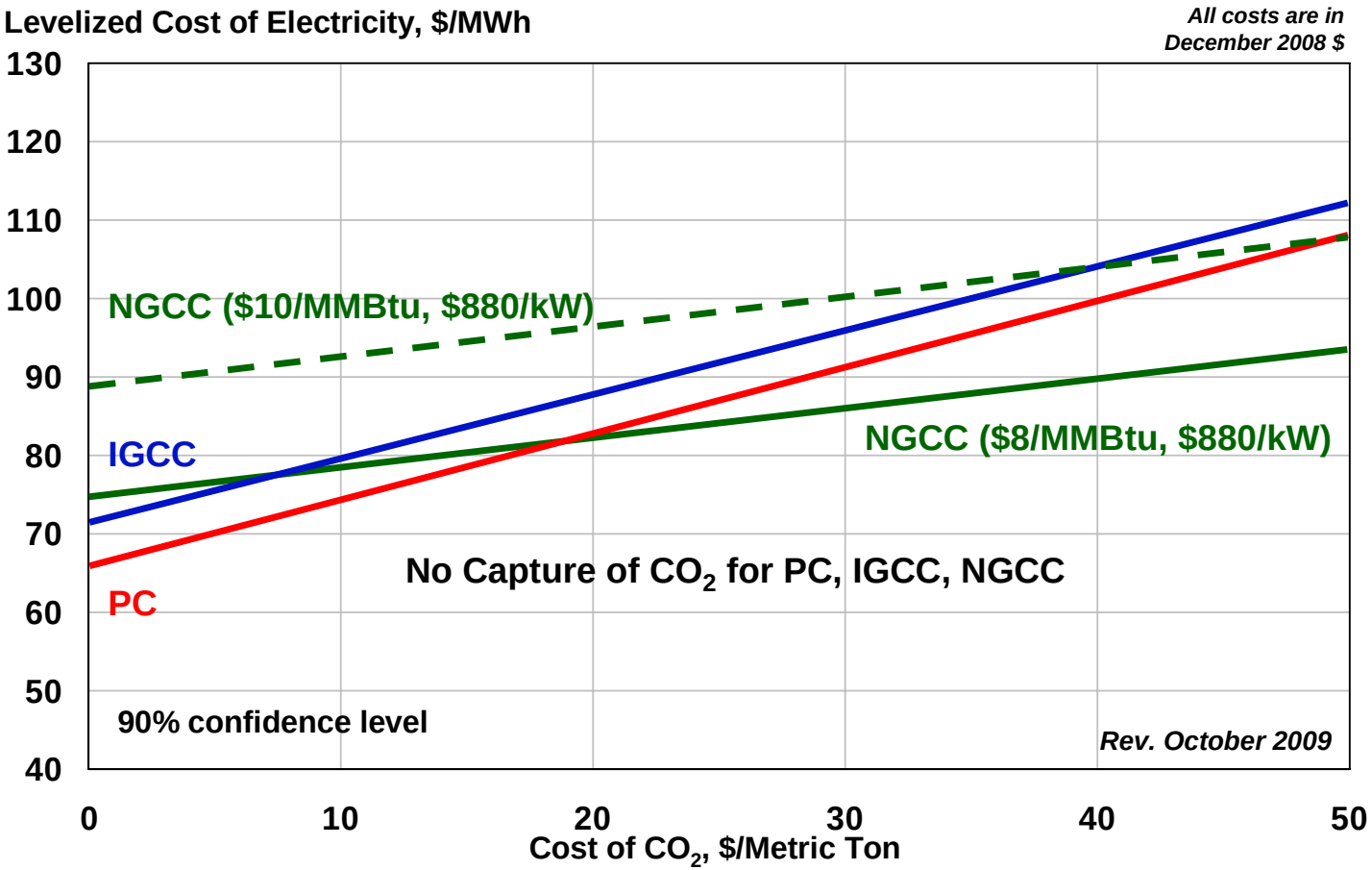
Natural Gas Combined Cycle – 2015



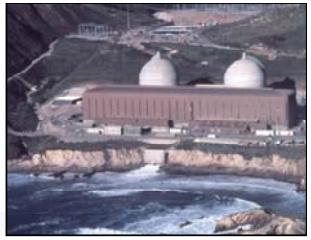
NGCC Fuel Cost Sensitivity Comparison – 2015

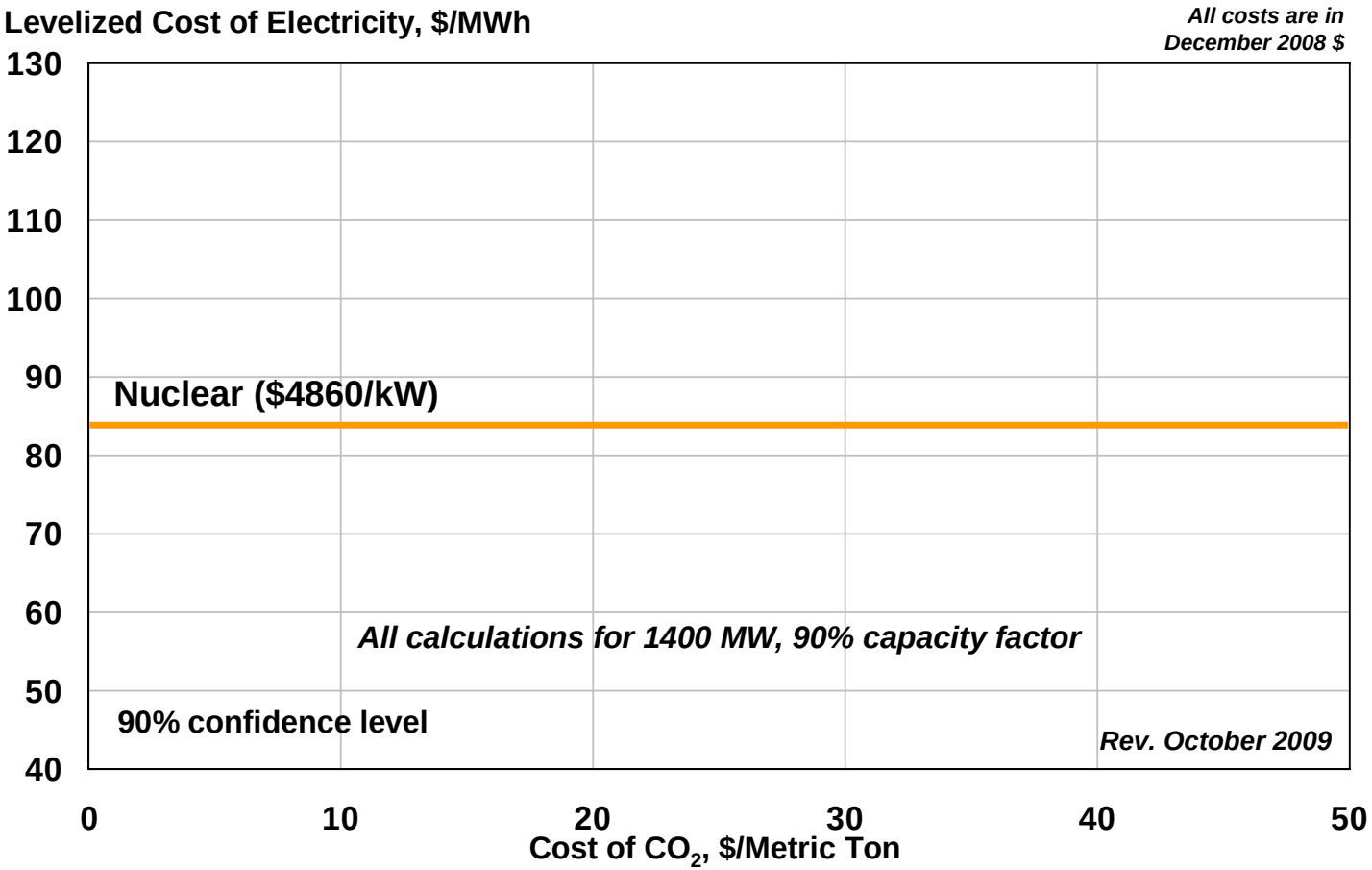


PC, IGCC, NGCC Comparison – 2015

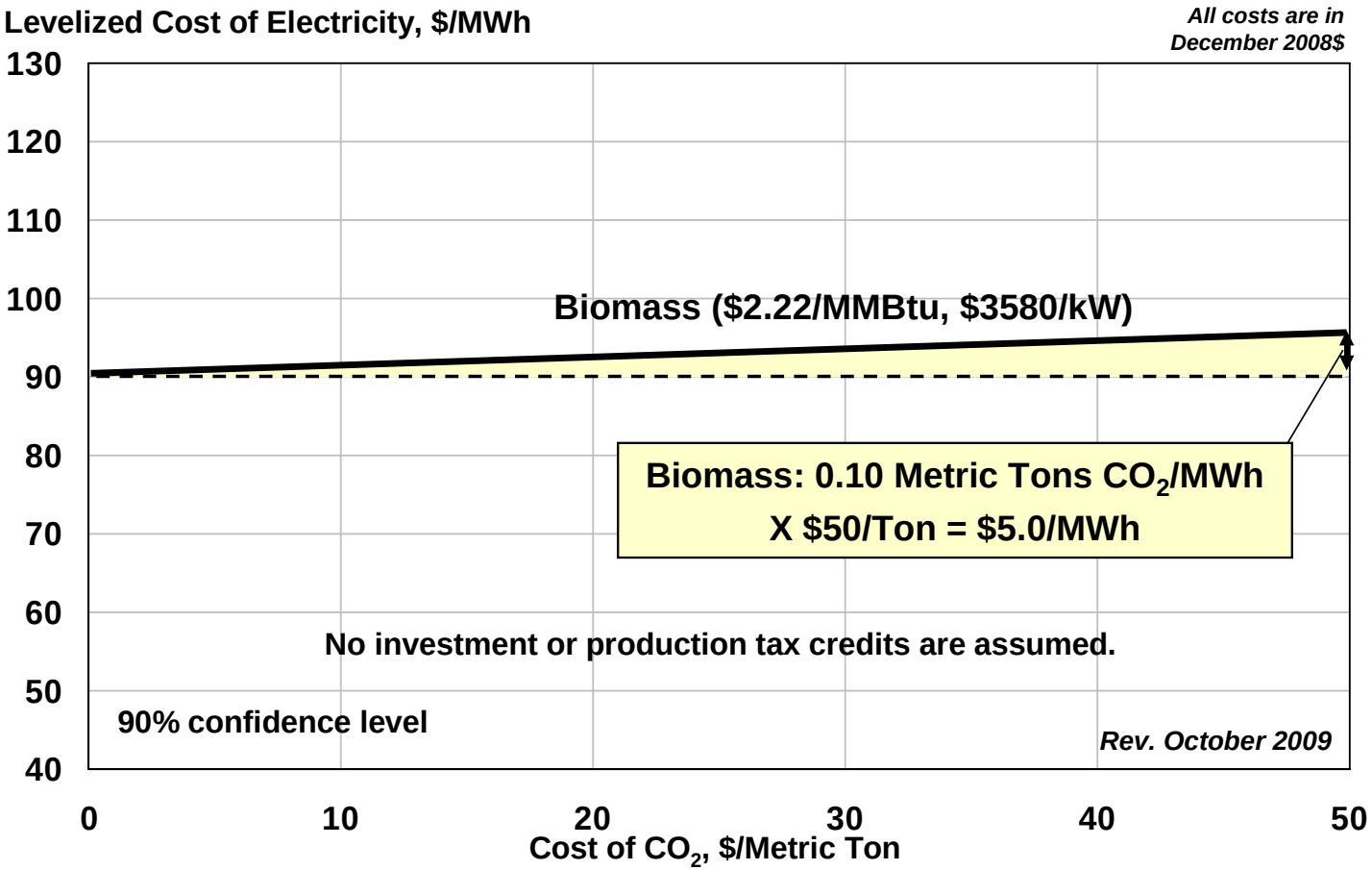


Nuclear Data Range – 2015

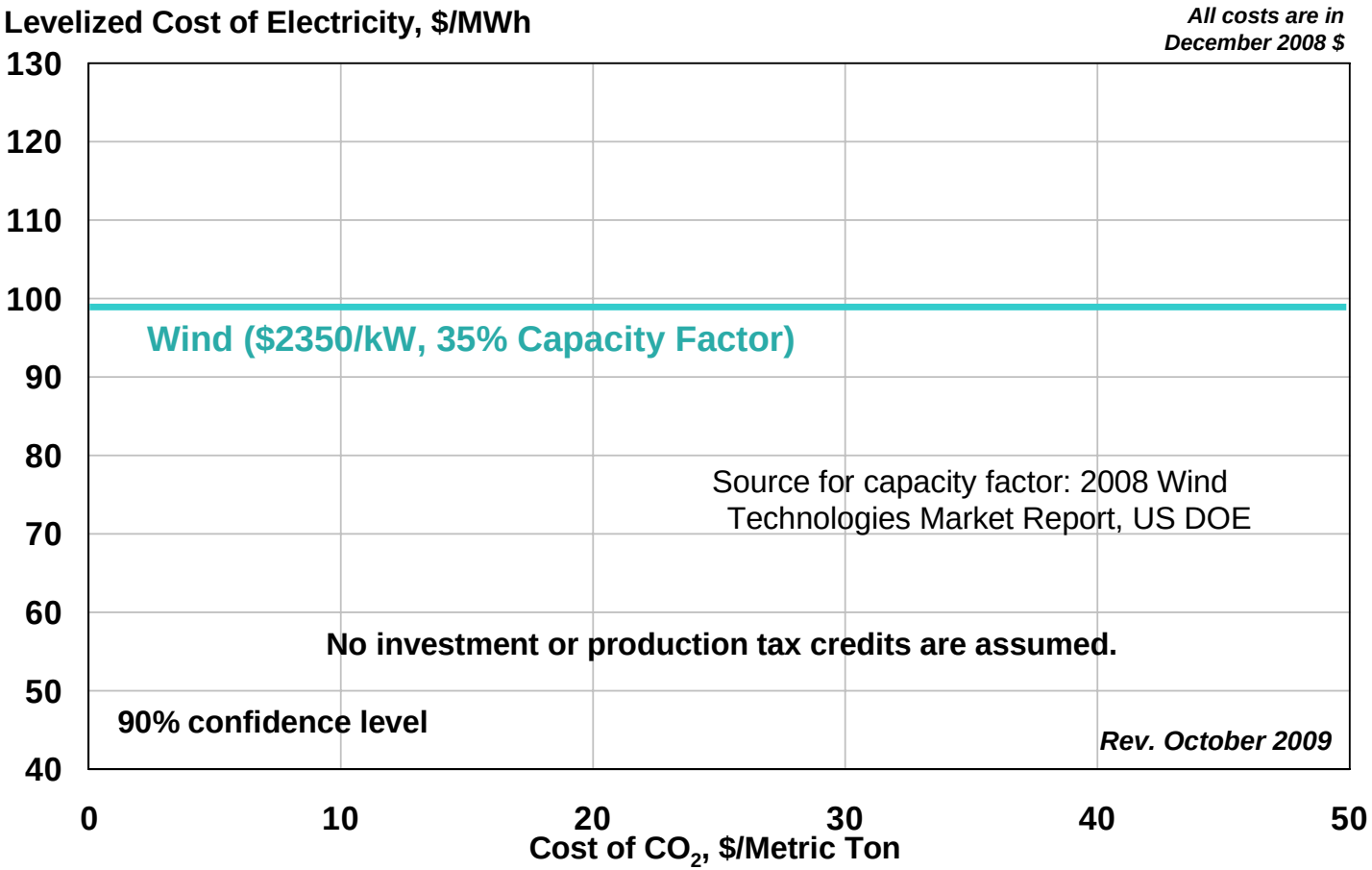




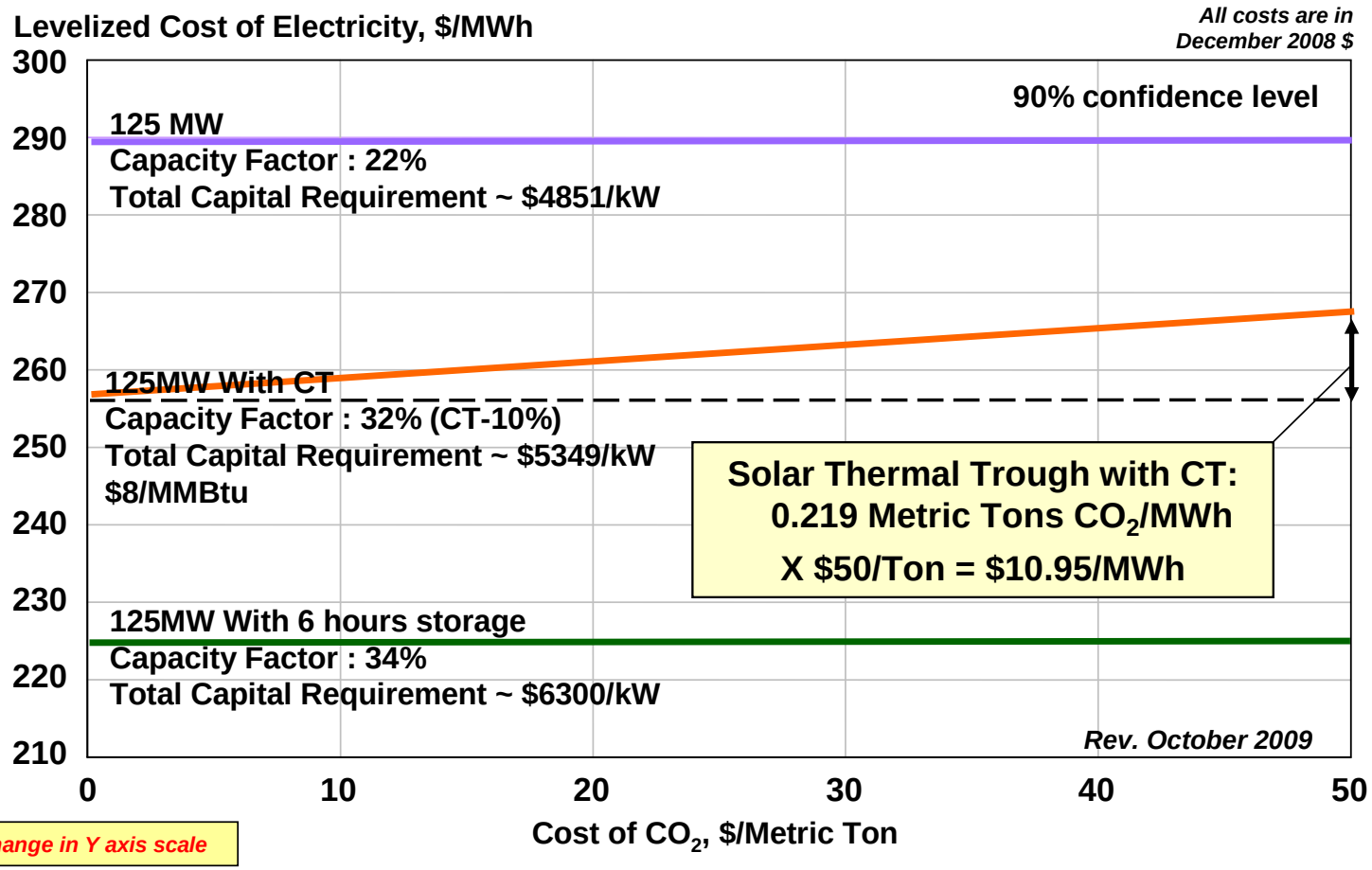
Biomass – 2015



Wind – 2015

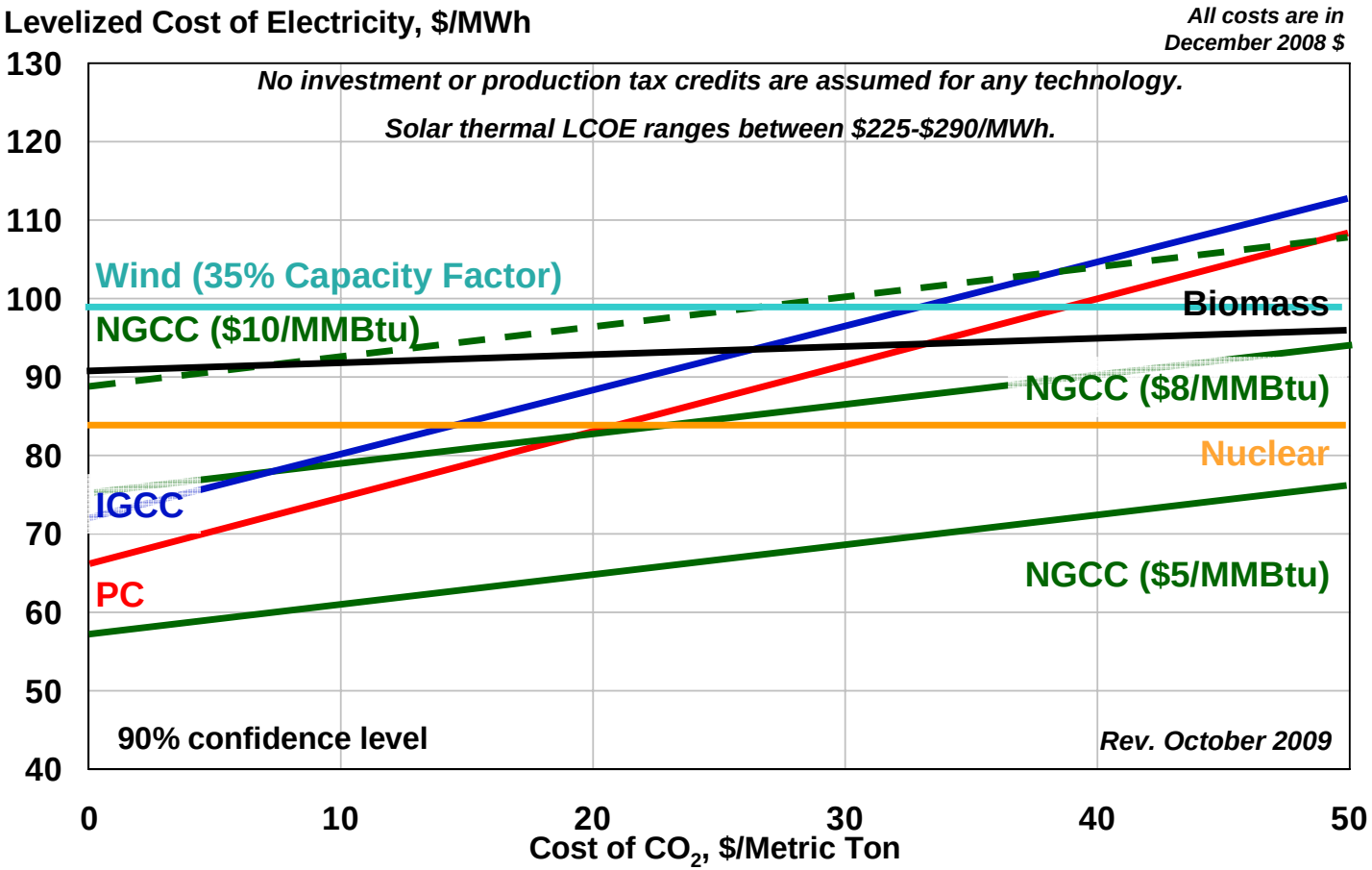

Levelized Cost of Electricity, $/MWh
All costs are in December 2008 $
130
120
110
100
90
80
70
60
50
40
Wind ($2350/kW, 35% Capacity Factor)
Source for capacity factor: 2008 Wind Technologies Market Report, US DOE
No investment or production tax credits are assumed.
90% confidence level
Rev. October 2009
0
10
20
30
40
50
Cost of CO_2, $/Metric Ton

Solar Thermal Trough Design – 2015



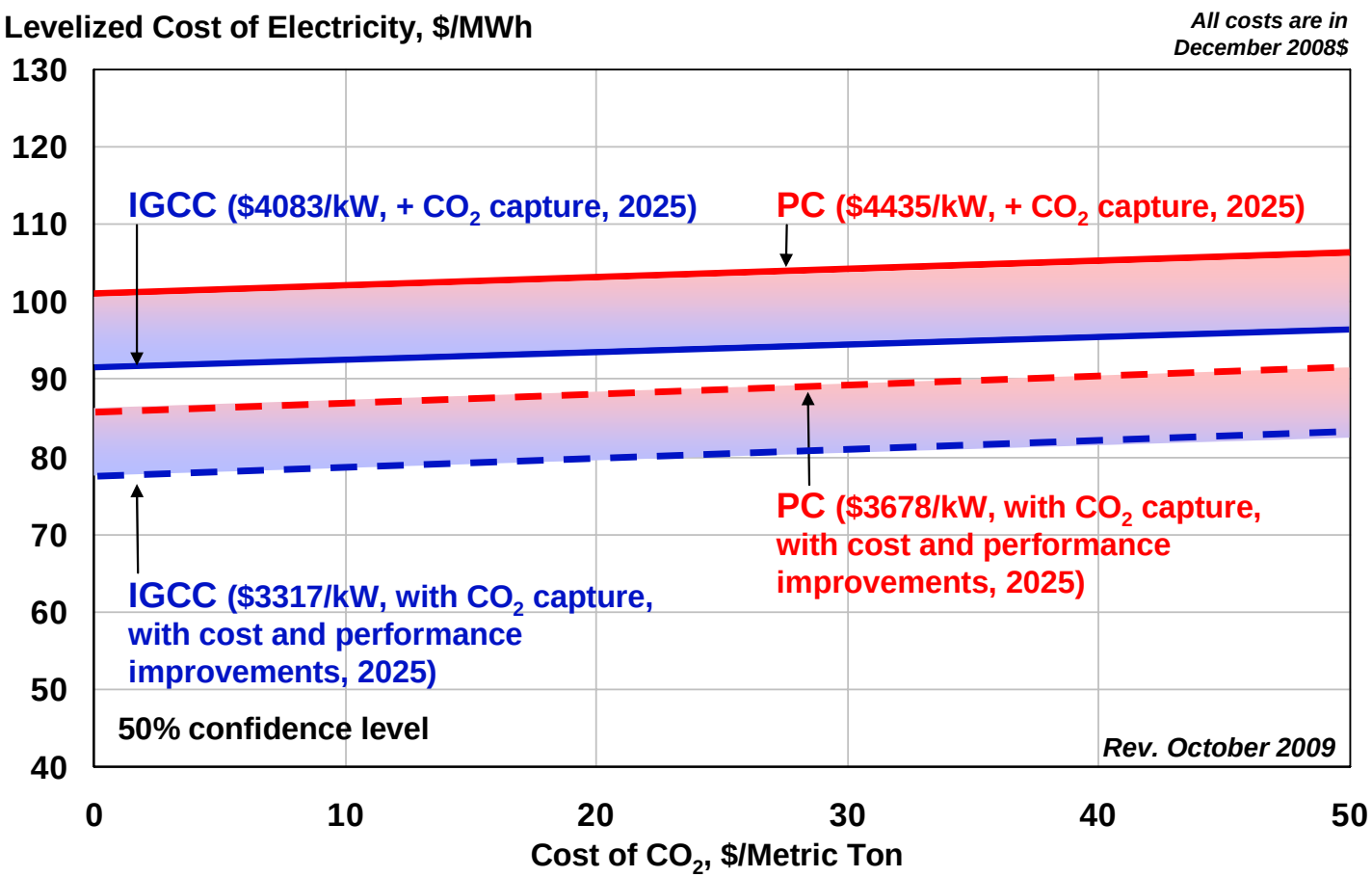
Note change in Y axis scale

Comparative Levelized Costs of Electricity – 2015

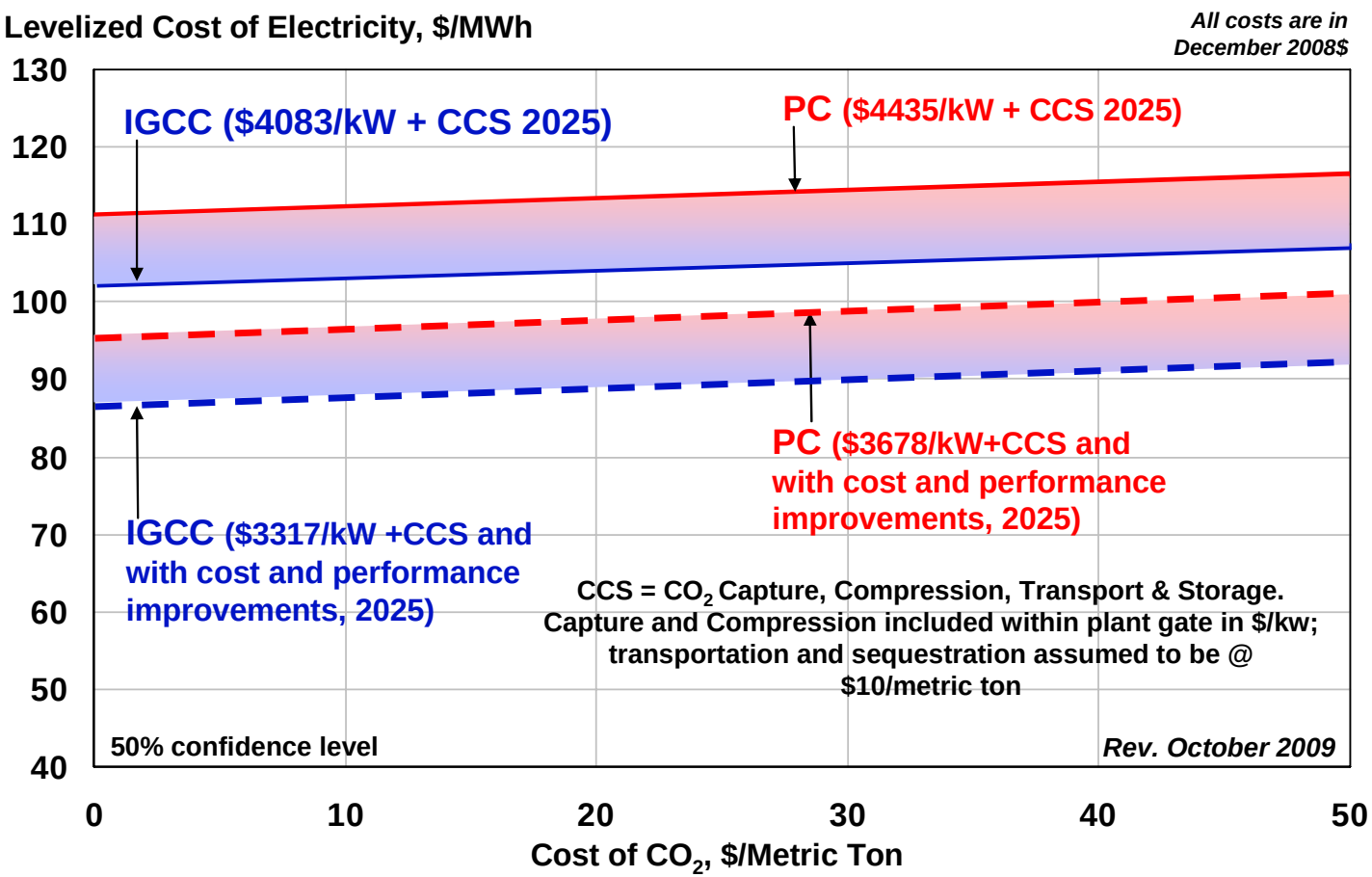


Longer-Term: 2025

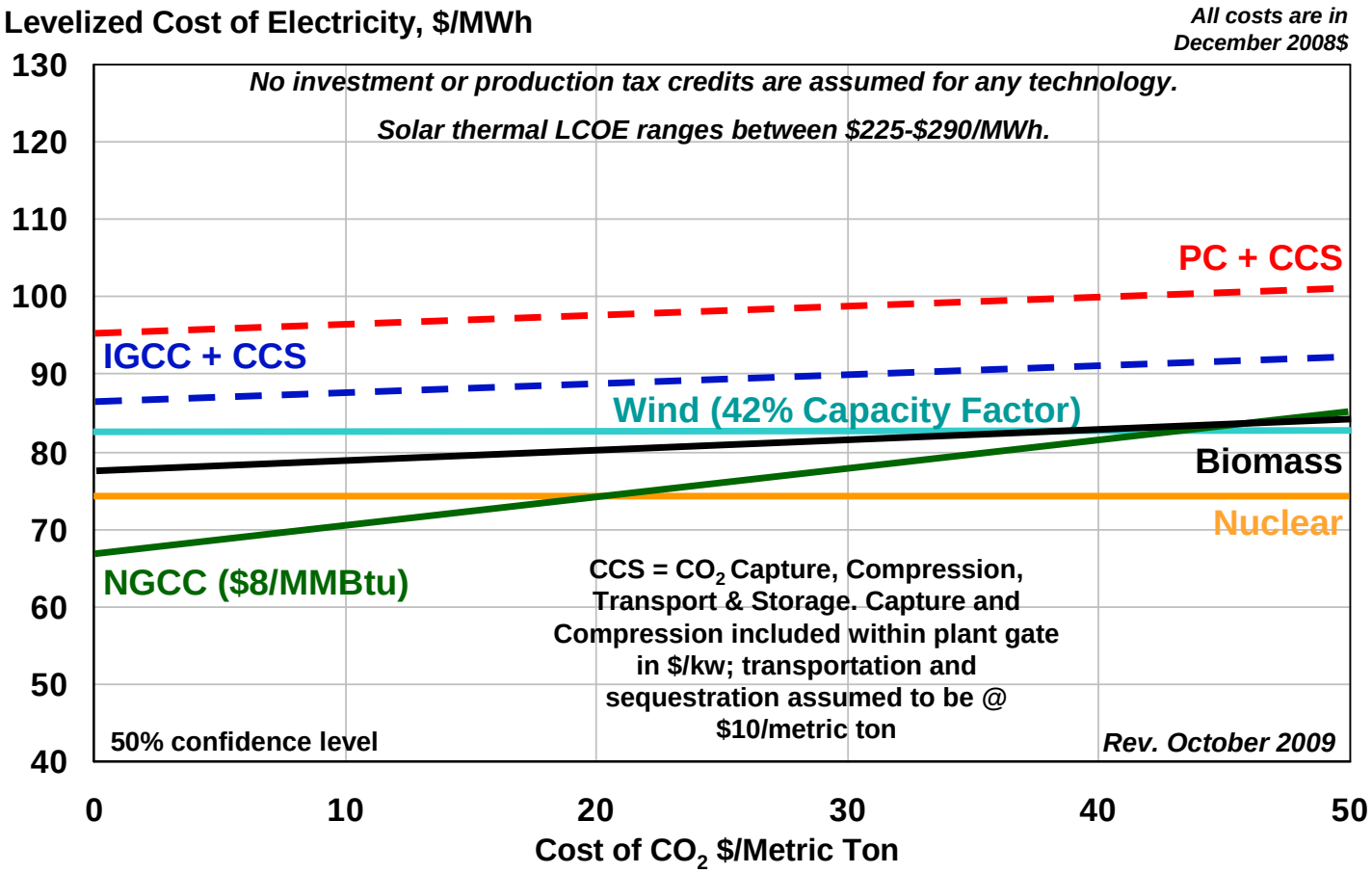
Impact of CO_2 Removal and Cost and Performance Improvements on Levelized Cost of Electricity – 2025



Impact of CO_2 Removal and Cost and Performance Improvements on Levelized Cost of Electricity – 2025



Comparative Levelized Costs of Electricity – 2025



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
  - Dedicated biomass feedstock costs could raise the feedstock price and levelized cost of electricity (LCOE) substantially
  - As optimum sites are depleted for siting of wind turbines, the assumed national average wind capacity factor could go down substantially from 42%
  - If the nuclear Total Capital Requirement (TCR) gets closer to $6000-$7000, the LCOE for nuclear could go up substantially
- Extraordinary opportunity to develop and demonstrate a portfolio of very low cost generation technologies.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together…Shaping the Future of Electricity

1019539

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