ESMAP Technical Paper 121/07
December 2007

Technical and Economic Assessment of Off-grid, Mini-grid and Grid Electrification Technologies




ESMAP

Energy Sector Management Assistance Program

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The Energy Sector Management Assistance Program (ESMAP) is a global technical assistance partnership administered by the World Bank since 1983 and sponsored by bilateral donors. ESMAP's mission is to promote the role of energy in poverty reduction and economic growth in an environmentally responsible manner. Its work applies to low-income, emerging, and transition economies and contributes to the achievement of internationally agreed development goals through knowledge products such as free technical assistance; specific studies; advisory services; pilot projects; knowledge generation and dissemination; training, workshops, and seminars; conferences and round-tables; and publications.

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Energy and Mining Sector Board
The World Bank Group

Energy Sector Management Assistance Program

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Acronyms and Abbreviations

ACSR	aluminum conductor steel reinforced
AD	anaerobic digestion
AFBC	atmospheric fluidized bed combustion
AFUDC	allowance for funds used during construction
AHEC	Alternate Hydro Energy Centre
BoS	balance of system
CCGT	combined cycle gas turbine
CFB	circulating fluidized bed
CHP	combined heat and power
CT	combustion turbine
DD	direct drive
DFIG	doubly-fed induction generator
DRR	dose-response relationship
DSS	direct solar steam
EGS	engineered geothermal systems
EnTEC	Energy Technologies Enterprises Corporation
EPC	engineering, procurement and construction
EPRI	Electric Power Research Institute
ESHA	European Small Hydro Association
ESP	electrostatic precipitator
EWEA	European Wind Energy Association
FGD	flue gas desulfurization
FY	fiscal year (July 1-June 30)
GDP	gross domestic product
GEA	Global Energy Associates, Inc.
GEF	Global Environment Facility

GHGs	Greenhouse gases
HRSG	heat recovery steam generator
HRT	hydraulic retention time
IAP	infrastructure action plan
IBRD	International Bank for Reconstruction and Development
IC	internal combustion
ICB	international competitive bidding
IDA	International Development Association
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IN-SHP	International Network for Small Hydro Power
JICA	Japan International Cooperation Agency
LAC	Latin America and Caribbean
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MCFC	molten carbonate fuel cell
MENA	Middle East North Africa
MDGs	Millennium Development Goals
MSW	municipal solid waste
NERC	North American Reliability Council
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PAFC	phosphoric acid fuel cell
PC	pulverized coal
PEFC	polymer electrolyte fuel cell
PERI	Princeton Energy Resources International
PM	particulate matter
PV	photovoltaic
RE	renewable energy
RETs	renewable energy technologies
RoR	run-of-the-river
RPM	resolutions per minute
SC	SuperCritical
SCR	selective catalytic reduction

SHP	small hydro power
SNCR	selective noncatalytic reduction
SOFC	solid oxide fuel cell
SPV	solar photovoltaic
SVC	Static VAR Compensato
TAG	Technical Assessment Guide
TCR	total capital requirement
T&D	transmission and distribution
TPC	total plant cost
TPI	total plant investment
USC	UltraSuperCritical
USDoE	The United States Department of Energy

Units of Measure

AC	alternating current
C	celsius
DC	direct current
F	fahrenheit
Kg	kilogram (s)
kV	kilo volt
kW	kilo watt (s)
kWh	kilo watt (s) per hour
m	meter (s)
MW	mega watt (s)
PPM	parts per million
V	volt
W	watt

Chemical Symbols

C	carbon
$CaSO_4$	calcium sulfate
CO	carbon monoxide
CO_2	carbon dioxide
CH_4	methane
H	hydrogen
HCl	hydrogen chloride
Hg	mercury
H_2S	hydrogen sulfide
K	potassium
N	nitrogen
NA	sodium
NO_x	nitrogen oxides
NH_3	ammonia
O	oxygen
SiO_2	silica
SO_2	sulfur dioxide
SO_x	sulfur oxides

Foreword

Helping power sector planners in developing economies to factor in emerging electrification technologies and configurations is essential to realizing national electrification agendas at minimum cost. New generation technologies, especially based on renewable energy (RE), and new electrification approaches, especially based on stand-alone mini-grids or off-grid configurations, are part of the growing complexity which electrification policy makers and power system planners must be able to factor into their investment programs.

This report is part of the Energy and Water Department's commitment to providing new techniques and knowledge which complement the direct investment and other assistance to electrification as provided by the International Bank for Reconstruction and Development (IBRD) and the International Development Association (IDA).

Our hope is that it will stimulate discussion among practitioners both within the World Bank and, in the larger community of power system planners. We note that the findings and results are imperfect at best and that much additional analytic work is required to keep up with the growing variety of power generation technologies and increasing complexity of formulating least-cost power sector development and electrification plans.

Jamal Saghir
Director
Energy and Water Department
Chair, Energy and Mining Sector Board
The World Bank

Acknowledgments

The electrification assessment study was undertaken by a team comprising Toyo Engineering Corporation, Chubu Electric Power Co. Inc., Princeton Energy Resources International (PERI), Energy Technologies Enterprises Corp (EnTEC), and Global Energy Associates, Inc (GEA). The report itself was prepared by several authors including Mr. K. R. Umesh (Toyo Engineering Company), Mr. Takashi Nakase, Mr. Keiichi Yoneyama and Toshiomi Sahara (Chubu Electric Power Company), Mr. Stratos Tavoulareas (EnTEC), Mr. Mahesh Vipradas (TERI) and Mr. Grayson Heffner (GEA). Mr. Chuck McGowan of Electric Power Research Institute (EPRI), and Mr. Joe Cohen and Mr. John Rezaiyan of PERI provided many helpful comments on the technical and economic assumptions underlying our assessment. The study and report preparation were managed by Mr. Masaki Takahashi of the Energy and Water Department with the assistance of Mr. Anil Cabraal.

The study team members and the World Bank staff would like to dedicate this report to the memory of Dr. Tom Schweizer of Princeton Energy Resources International (PERI) who passed away last year as the assessment phase of the study was nearing completion. Tom was a dedicated and invaluable colleague always ready to cooperate and offer his services and advice.

Please address any questions or comments about this report to Mr. Masaki Takahashi (mtakahashi@worldbank.org).

Executive Summary

Background

Today's levels of energy services fail to meet the needs of the poor. Worldwide, two billion people rely on traditional biomass fuels for cooking and 1.6 billion people do not have access to electricity. Unless investments in providing modern energy services are expanded significantly, this number is expected to actually increase over the next 30 years (International Energy Agency [IEA], 2002). This lack of access to quality energy services, especially electricity, is a situation which entrenches poverty, constrains the delivery of social services, limits opportunities for women and girls, and erodes environmental sustainability at the local, national and global levels. Ignoring the situation will undermine economic growth and exacerbate the health and environmental problems now experienced in many parts of the world.

Developing and transition countries face huge investments in providing the energy access needed to achieve the Millennium Development Goals (MDGs). The IEA estimates the electricity sector investment requirements in developing countries to reach the MDG goal of halving poverty to be US$16 billion annually over the next 10 years (IEA, 2004). Mobilizing such investment and, in particular, undertaking the challenges of rural electrification will require strong political determination, a willingness to prioritize electrification within the overall development agenda and considerable skill in the selection and implementation of technical and economic strategies for electrification.

Experience throughout the world has shown that there is no single or unique way of achieving electrification, either from a financing and implementation viewpoint or from an electrification technology viewpoint. Furthermore, the range of electrification technologies is constantly expanding, and the factors determining the ultimate affordability, availability and sustainability of a particular electrification scheme are becoming increasingly complex. Developments in generation technology and electrification business models have resulted in increasing diversity in how electricity is generated and delivered to end users, including grid-connected mini-grid and off-grid arrangements.

This growing diversity of electrification arrangements is reflected in the World Bank's patterns of lending for electrification. A recent review of the World Bank energy projects approved during fiscal year (FY) 2003 through 2005 identified almost US$500 million in direct physical investments in electricity access (The World Bank, 2006). The portfolio review identified four categories of electricity access investment – Grid-based Peri-urban Electrification; Grid-based Rural Electrification; Off-grid Rural Electrification; and Electrification Funds (Table 1). The review confirmed that grid-connected electrification remained the dominant electrification arrangement, but identified considerable regional variations, with off-grid investment important in Africa and predominant in Latin America and Caribbean (LAC). Off-grid electrification comprised almost 10 percent of the total assistance to electrification provided by the World Bank over the past three fiscal years. This proportion is expected to grow along with progress toward universal access, as remaining populations will be more difficult to economically electrify using conventional grid extension arrangements.

Table 1: World Bank FY 2003-05 Investment in Electricity Access (US$ millions)

Region	*Grid Peri-urban*	*Grid Rural Electrification*	*Off-grid Electrification*	*Rural Energy Fund*	*Total*
Africa	US$76.6	US$35.2	US$30.2	US$31.2	US$173.2
E Asia Pacific	US$0.0	US$235.0	US$3.7	US$8.3	US$247.0
L America Car	US$0.0	US$3.0	US$7.0	US$0.0	US$10.0
South Asia	US$26.0	US$0.0	US$5.5	US$24.6	US$56.1
N Africa Med	US$0.0	US$0.0	US$0.0	US$0.0	US$0.0
E Europe CA	US$0.0	US$0.0	US$0.0	US$0.0	US$0.0
Total	**US$102.6**	**US$273.2**	**US$46.4**	**US$64.1**	**US$486.3**

Source: The World Bank, 2006.

Purpose

The purpose of this report is to convey the results of an assessment of the current and future economic readiness of electric power generation alternatives for developing countries. The objective of the technical and economic assessment was to systematically characterize the commercial and economic prospects of renewable and fossil fuel-fired electricity generation technologies now, and in the near future.

Our hope is that this assessment will be useful to electrification planners concerned with anticipating technological change in the power sector over the next 10 years, especially as regards emerging RE technology, new prime mover technology and hybrid configurations which can potentially deliver improved performance and better economics for a given electrification situation. We also wanted to provide these planners and policy makers with systematic comparisons of the economics of various technologies when configured in grid-connected, mini-grid and off-grid applications.

Scope

We examined power generation technologies across a size range of 50 watt (W) to 500 mega watt (s) (MW) organized into three distinct electricity delivery configurations: off-grid, mini-grid and grid (Table 2). Generation technologies examined included renewable energy technologies (RETs), (photovoltaic [PV], wind, geothermal, hydro, biomass-electric, biogas-electric); conventional generation technologies (gasoline or diesel generator; oil/gas steam-electric, combustion turbines (CTs) and combined cycle; coal-fired steam-electric); and emerging technologies (integrated gasification combined cycle [IGCC], Atmospheric Fluidized Bed Combustion [AFBC], fuel cells and microturbines). The economic assessment was performed for three different time periods (2005, 2010 and 2015) in order to incorporate projected cost reductions from scaling-up of emerging technologies. A levelized analysis of capital and generation costs was conducted in economic, rather than financial terms, to allow generic applications of results to any developing country. Capital and generation cost projections incorporated uncertainty analysis, allowing the results to reflect sensitivity to key input assumptions. The study results make it possible to compare the levelized economic costs of electricity technologies over a broad range of deployment modes and demand levels, both at present, and in the future.

Table 2: Generation Technology Options and Configurations

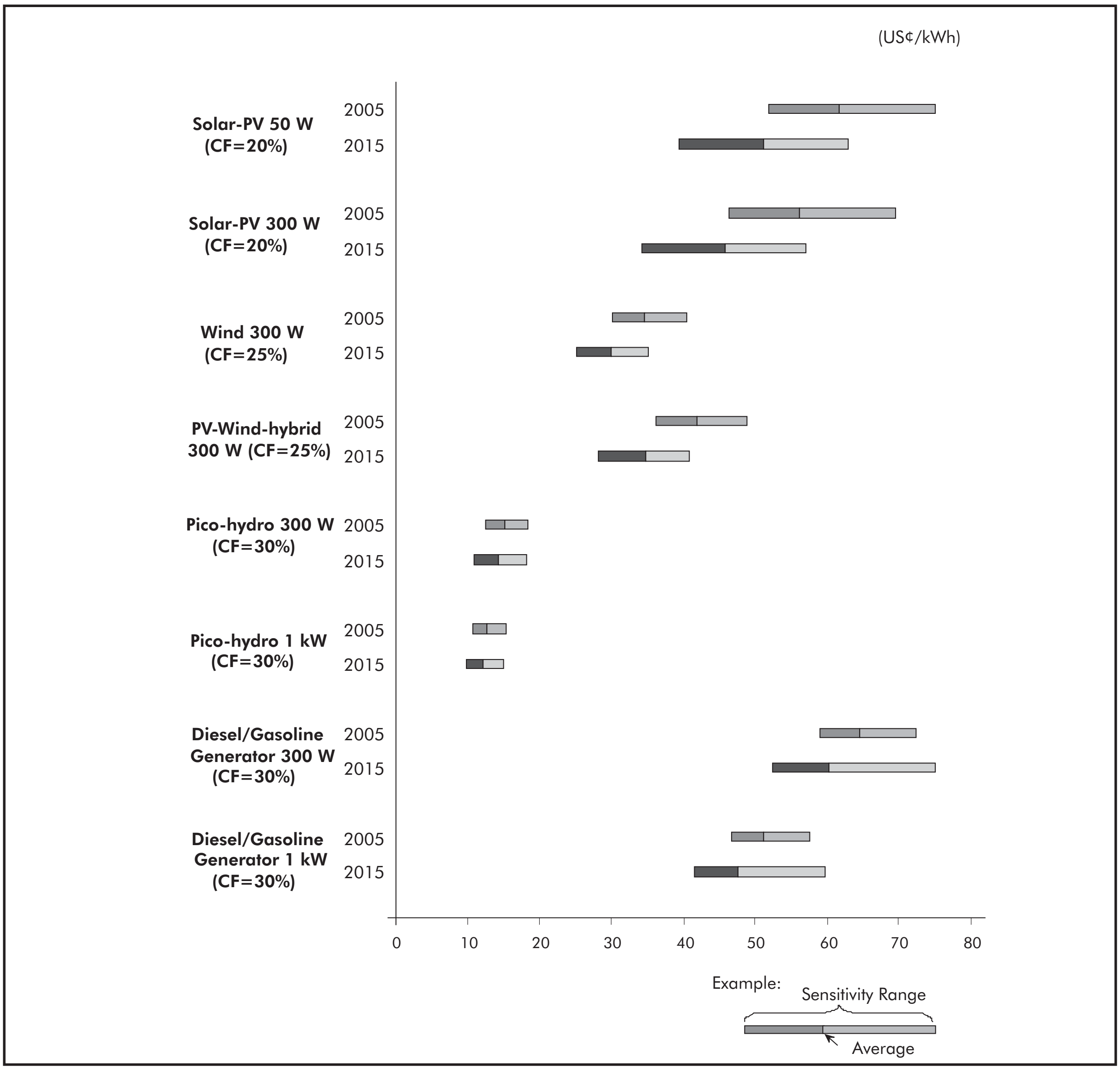
Generating-types	*Life Span (Year)*	*Off-grid*		*Mini-grid*		*Grid-connected*			
						Base Load		*Peak*	
		Capacity	*CF (%)*	*Capacity*	*CF (%)*	*Capacity*	*CF (%)*	*Capacity*	*CF (%)*
Solar-PV	20 25	50 W 300 W	20	25 kW	20	5 MW	20		
Wind	20	300 W	25	100 kW	30	10 MW 100 MW	30		
PV-wind-hybrids	20	300 W	25	100 kW	30				
Solar Thermal With Storage Solar Thermal Without Storage	30 30					30 MW 30 MW	50 20		
Geothermal Binary Geothermal Binary Geothermal Flash	20 30 30			200 kW	70	 20 MW 50 MW	 90 90		
Biomass Gasifier	20			100 kW	80	20 MW	80		
Biomass Steam	20					50 MW	80		
MSW/Landfill Gas	20					5 MW	80		
Biogas	20			60 kW	80				
Pico/Microhydro	5 15 30	300 W 1 kW	30 30	 100 kW	 30				
Mini Hydro	30					5 MW	45		
Large Hydro	40					100 MW	50		
Pumped Storage Hydro	40							150 MW	10
Diesel/Gasoline Generator	10 20	300 W, 1 kW	30	 100 kW	 80	 5 MW	 80	 5 MW	 10
Microturbines	20			150 kW	80				
Fuel Cells	20			200 kW	80	5 MW	80		
Oil/Gas Combined Turbines	25							150 MW	10
Oil/Gas Combined Cycle	25					300 MW	80		
Coal Steam Subcritical Sub, SC, USC	30 30					300 MW 500 MW	80 80		
Coal IGCC	30 30					300 MW 500 MW	80 80		
Coal AFB	30 30					300 MW 500 MW	80 80		
Oil Steam	30					300 MW	80		

Findings

The assessment process revealed emerging trends in terms of the relative economics of renewable and conventional generation technologies according to size and configuration. In interpreting and applying these findings, it should be kept in mind that the assessment effort is a desk study bound by time (technology and prices are not static) and method (it consolidates secondary source information rather than generating new content).

- **Renewable energy is more economical than conventional generation for off-grid (less than 5 kW) applications.** Several RE technologies – wind, mini-hydro and biomass-electric – can deliver the lowest levelized generation costs for off-grid electrification (Figure 1), assuming availability of the renewable resource. Pico-hydro, in

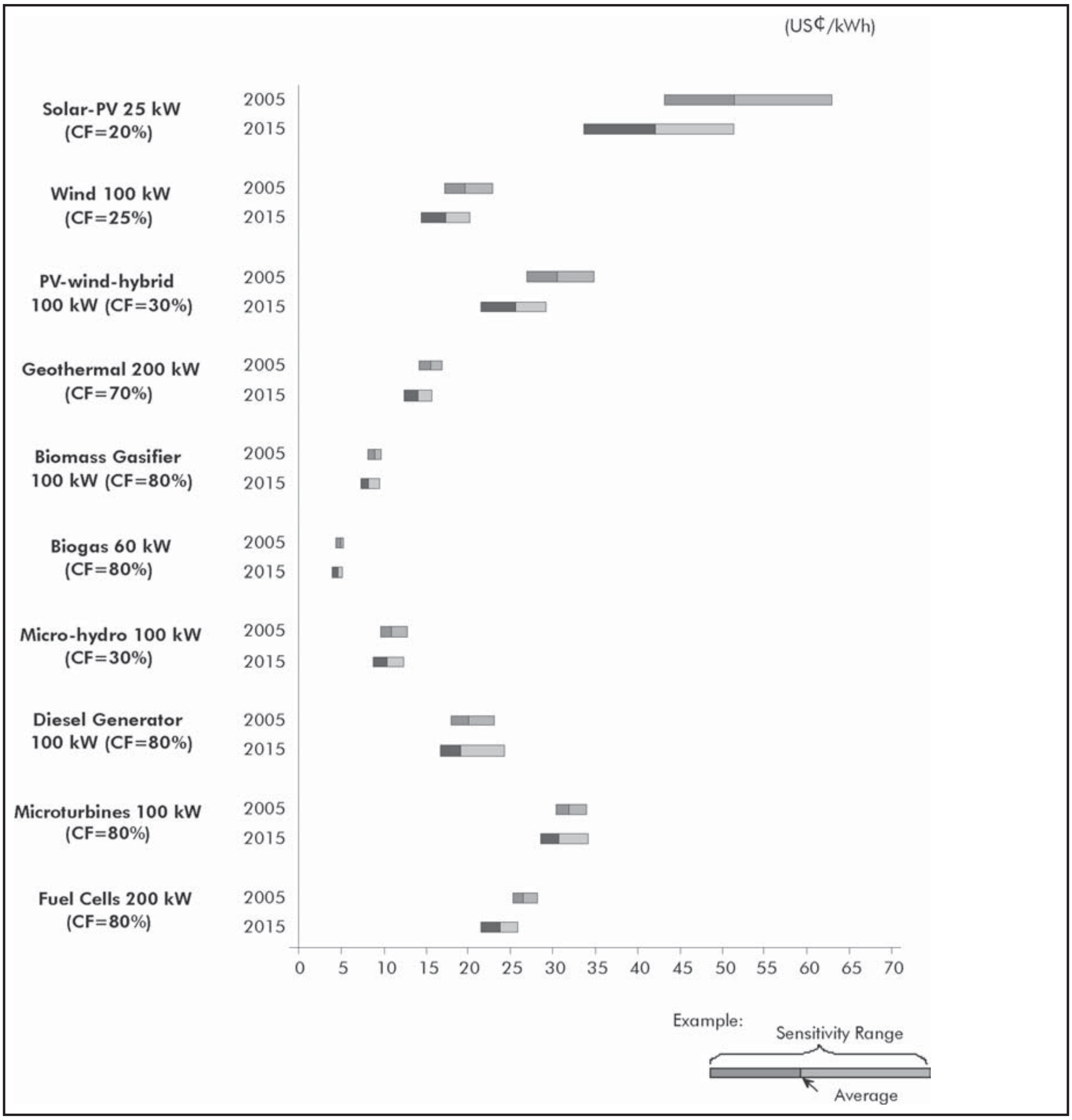
Figure 1: Off-grid Forecast Generating Cost



particular, can deliver electricity for US¢10-20/kilo watt (s) per hour (kWh), less than one-quarter of the US¢40-60/kWh for comparably-sized gasoline and diesel engine generators. Even relatively expensive RET (solar PV) is comparable in levelized electricity costs to the small fuel-using engine generators under 1 kilo watt (s) (kW) in size.

- **Several renewable energy technologies are potentially the least-cost mini-grid generation technology.** Mini-grid applications are village- and district-level isolated networks with loads between 5 kW and 500 kW. The assessment results suggest several RETs (biomass, geothermal, wind and hydro) may be the most economical generation choice for mini-grids, assuming a sufficient renewable resource is available (Figure 2).

Figure 2: Mini-grid Forecast Generating Costs



Two biomass technologies – biogas digesters and biomass gasifiers – seem particularly promising, due to their high capacity factors and availability in size ranges matched to mini-grid loads. Since so many RE sources are viable in this size range, mini-grid planners should thoroughly review their options to make the best selection.

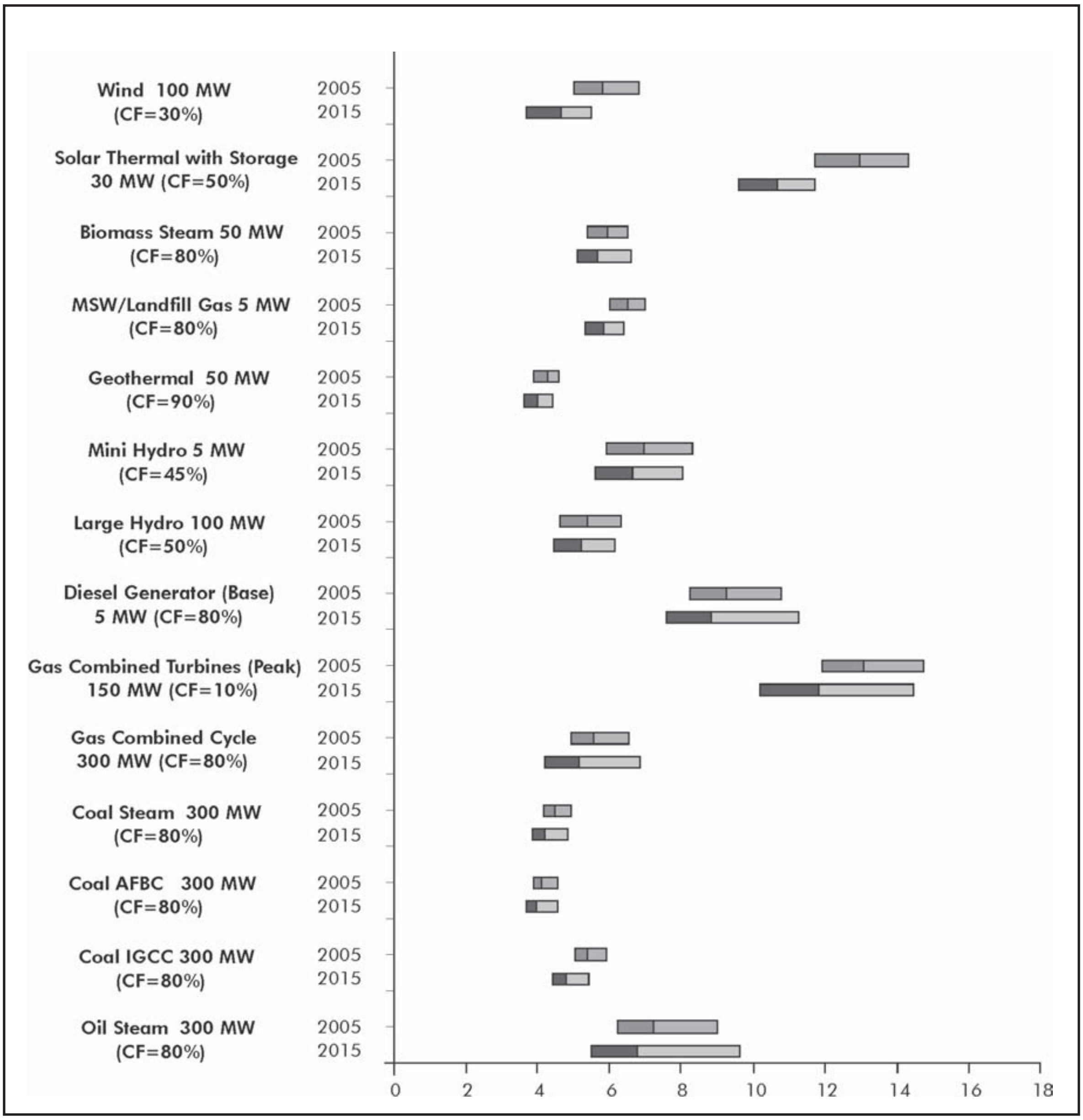
- **Conventional power generation technologies (open cycle and combined cycle gas turbines [CCGTs], coal- and oil-fired steam turbines) remain more economical for most large grid-connected applications, even with increases in oil price forecasts (Figure 3).** Site-specific considerations, such as load profile, demand and cost differentials between oil, natural gas and coal prices, determine which configuration is the least expensive. Using SuperCritical or UltraSuperCritical (USC) for very large (over 500 MW) power plants is most cost-effective when fuel prices are high and carbon dioxide (CO_2) reductions are sought.

- **Two new coal technologies have considerable potential for developing economies.** Two new coal-fired power plant technologies – Integrated Gasification Combined Cycle (IGCC) and AFBC – are attracting considerable attention by planners of large power grids in countries with coal or lignite reserves. AFBC is already commercially available up to 300 MW size, and is used widely worldwide, including China and India. This technology is competitive in situations where low quality inexpensive fuel is available and when sulfur dioxide (SO_2) emission regulations require a wet scrubber. In the 100 to 300 MW range, the circulating fluidized bed (CFB) option is preferable. The AFBC option may also be applicable to smaller thermal power plants (under 100 MW) using biomass and municipal solid wastes (MSW). IGCC is in the early commercialization stage and could become a viable and competitive option in the future given its excellent environmental performance (Figure 3).

Considerations for Power System Planners

Power system planners generally operate on an incremental basis, with new capacity additions selected to accommodate the location and pace of load growth on a least-cost basis. The findings provided here suggest that scale is a critical aspect affecting the economics of different generation configurations. When the national or regional grid is developed and includes sufficient transmission capacity, and incremental load growth is fast, large, central-station gas combined cycle and coal-fired power plants would clearly be the least-cost alternatives. However, if the size of the grid is limited, or the incremental load growth is small, it may make economic sense to add several smaller power stations rather than one very large power station. Taking advantage of local resources such as indigenous coal, gas, biomass or geothermal or wind or hydro, and constructing smaller power stations,

Figure 3: Grid-connected Forecast Generating Costs (US¢/kWh)



See Annex 4 for results for more grid-connected applications.

may provide energy security and avoid some of the uncertainty associated with international fuel prices as well as the risk associated with financing and constructing very large power plants.

Recommendations for Future Work

The findings described above suggest that choosing generation technologies and electrification arrangements is becoming a more complicated process. New technologies are becoming more economical and technologically mature, uncertainty in fuel and other inputs is creating increasing risk regarding future electricity costs, and old assumptions about economies of scale in generation may be breaking down. The assessment methods used here provide a useful comparison among technologies, but need further refinement before becoming the basis of national or regional electrification plans. Accounting for the locational and stochastic variability of renewable resources, as well as balancing costs, land costs, labor and transport costs, all need further investigation, as does the method of accounting for the incremental cost of delivering electricity. The need to accommodate environmental externalities in the economic assessment also needs more attention. Finally, the relative economics of conventional vs. RE is largely driven by forecasts of fuel prices together with certain construction and manufacturing materials prices, such as steel, concrete, glass and silicon. All these commodity prices are increasingly subject to uncertainties and price fluctuations in possibly countervailing directions, which make forecasts of future generation costs extremely uncertain. Additional work, including use of hedging or other financial risk mitigation instruments, is needed to quantify and reflect these future fuel and commodity price uncertainties as part of the electrification planning process.[1]

[1] *See, for example, "A Level Playing Field for Renewables: Accounting for the Other Externality Benefits." Shimon Awerbach, University of Sussex. Presented to the European Conference for Renewable Energy: Intelligent Policy Options, January 20, 2004.*

1. Introduction

This power generation technology assessment study is motivated by the World Bank's renewed commitment to both infrastructure development generally, and scaling up access to electricity, in particular. This renewed commitment to the importance of infrastructure within the overall development agenda is described in the 2003 infrastructure action plan (IAP), a comprehensive management tool, which will guide the World Bank Group's infrastructure business for the next few years. The action plan emphasizes more investments, as well as country diagnostic work and encouragement of more private participation, in order to reposition infrastructure as a key contributor to achieving the Millennium Development Goals (MDGs) (The World Bank, 2003).

Embedded within the Infrastructure Action Plan are commitments by the World Bank Group to scale up both investments in modern energy for the urban and rural poor, and its support for renewable energy (RE) development. Between 1994 and 2004, the World Bank (International Bank for Reconstruction and Development [IBRD] and International Development Association [IDA]) commitment in the power sector has totaled US$17 billion, a level that the IAP proposes to substantially increase. During the same period, IBRD and IDA commitments, together with carbon (C) financing and Global Environment Facility (GEF) cofinancing for RE, specifically, has totaled US$6 billion (The World Bank, 2005). At the 2004 Bonn International Conference on Renewable Energy, the World Bank Group agreed to increase its RE support by 20 percent each year for the next five years. Increased commitment by the World Bank Group in these two overlapping areas is essential, as the commitments made in Bonn by the developing countries alone is US$10 billion per year for the next 10 years, while annual power sector investment needs in developing and transition countries are expected to average US$280 billion per year – twice the level of investment in previous years (International Energy Agency [IEA], 2004).

Carrying out these global commitments, to scaling up access to electricity and investment in RE, requires the most up to date information on technologies and energy economics available. Assessment of the technical, economic and commercial prospects for electricity generation and delivery technologies is needed in order to make intelligent decisions regarding investments in delivering electricity services at the lowest economic cost, and with maximum social and environmental benefits. An up to date electricity generation and delivery knowledge base in an easily accessible form will help in providing the information needed for countries to incorporate the latest technology developments in their national electrification plans.

Technologies for power generation and delivery continue to emerge and find commercial application. New prime mover technology, emerging renewable technology, new and hybrid configurations combining to deliver improved power plant attributes and better economics of small systems, all combine to create a broad spectrum of choice for power system planning on a national, provincial, local, and even household level. The technical and economic assessment of electrification technologies provided here seeks to characterize and organize this broad spectrum of technology choice for urban and rural energy planners.

Purpose and Scope

The purpose of this report is to provide a technical and economic assessment of commercially available and emerging power generation technologies. The study was designed to cover the widest possible range of electrification applications faced by energy services delivery and power system planners, whether supply is provided through grid networks or stand-alone or mini-grid configurations. The assessment was conducted using a standard approach and is presented in a consistent fashion for each power generation technology configuration. The assessment time frame includes current status and forecast development trends over the period 2005-15, while the economic assessment considers a range of typical operating conditions (peak, off-peak) and grid configurations (off-grid, mini-grid, interconnected grid) for various scales of demand. The technology characterization reflects the current stage of commercialization, including indicative cost reduction trends over 10 years. The study outputs allows for comparison of levelized electricity costs for the full spectrum of electrification technologies over a matrix of deployment modes and demand levels.

Methodology

The methodology comprises a five-step process. First, a technology assessment was undertaken for each candidate generation technology. The assessment covered operating principles, application for electrification purposes and prospects for performance improvement and capital cost reduction. An environmental characterization came next, which focused on typical environmental impacts from normal operations using typical emission control measures and costs.[2] The assessment assumes use of emission controls in accordance with the World Bank environmental guidelines; these costs are included in the economic assessment. The third step was a capital cost assessment using a standard mathematical model and actual cost data (where available) and reflecting typical deployment.[3] Future capital costs of generation were then developed, based on technology forecasts (for example, learning curves) and incorporating uncertainties in equipment cost, fuel cost and capacity factor. The uncertainty analysis is a parametric analysis of variability in key inputs and generates a band of maximum and minimum costs for each period (2005, 2010 and 2015). Finally, levelized generating costs were calculated using a consistent economic analysis method, but differentiated according to deployment conditions. This last step also included an uncertainty analysis on the inputs to the levelized cost calculation, again generating a band of maximum and minimum costs for the 2005, 2010 and 2015 periods. All cost estimates were developed for a single reference location (India) to minimize any site-specific discrepancies when comparing technologies.

Costing Formulations and Projections

We selected commonly used formulations of capital costs and generation costs from the engineering economics literature. Capital cost is calculated on a unit basis (per [kilo watt (s) kW]) as the sum of equipment costs (including engineering) plus civil, construction and physical contingency costs. Operating costs are simply the sum of fixed and variable operation and maintenance (O&M) costs plus fuel costs expressed on a per unit output basis. Land cost is not included.

We define generating cost as the sum of capital cost and operating cost, expressed on a levelized unit cost basis (US$ per [kilo watt (s) per hour] kWh), with levelizing conducted over the economic life of the plant. Levelizing is done using a 10 percent real discount rate that is assumed to be the opportunity cost of capital.[4]

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[2] Capital and operating cost calculations assume generating equipment complies with the World Bank environmental guideline (Pollution Prevention and Abatement Handbook, July 1998). The Emission Standards are: (i) SOx (sulfur oxides) – <500 MW (mega watt (s) : 0.2 tpd/MW, or $\leq$2000 mg/Nm^3; (ii) NOx (nitrogen oxides – Coal: 750 mg/Nm^3; Oil: 460; Gas:320; Gas Turbine:125 for gas; 165 for diesel; 300 for fuel oil; and (iii) PM – 50 mg/Nm^3.

[3] As described in the Annexes, the cost assessment utilized a cost formulation based on the Electric Power Research Institute's Technical Assessment Guide (TAG).

[4] Detailed formulation of these cost equations is provided in Annex 2.

The analysis was conducted on an economic, rather than a financial basis. An economic analysis assesses the opportunity costs for the project; transfer payments such as taxes, duties, interest payments (including interest during construction) and subsidies are not included. Similarly, physical contingencies are included in the analysis, but price contingencies are not. The analysis is done in real 2004 US$. The environmental costs/benefits of a particular technology are given in physical quantities without any attempt at monetary valuation, as such valuations must be country- and site-specific.

Some technologies have the potential for significant capital cost reductions due to scaling up and technology improvements. The cost reduction potential varies according to the maturity of the technology and potential for improvements. Based on the literature and industry forecasts, we assumed cost reduction trajectories as shown in Table 1.1.

Table 1.1: Capital Cost Projections by Generation Technology

Decrease in Capital Cost (2004 to 2015)	*Generating Technology-type*
0%-5%	Geothermal, Biomass Steam, Biogas, Pico/Microhydro, Mini Hydro, Large Hydro, Pumped Storage, Diesel/Gasoline Generator, Coal Steam (SubCritical and SuperCritical), Oil Steam
6%-10%	Biomass Gasifier, MSW/Landfill, Gas Combustion, Gas Combined Cycle, Coal Steam USC, Coal AFBC
11%-20%	Solar-PV, Wind, PV-wind-hybrids, Solar-thermal, Coal-IGCC
>20%	Microturbine, Fuel Cells

Uncertainty Analysis

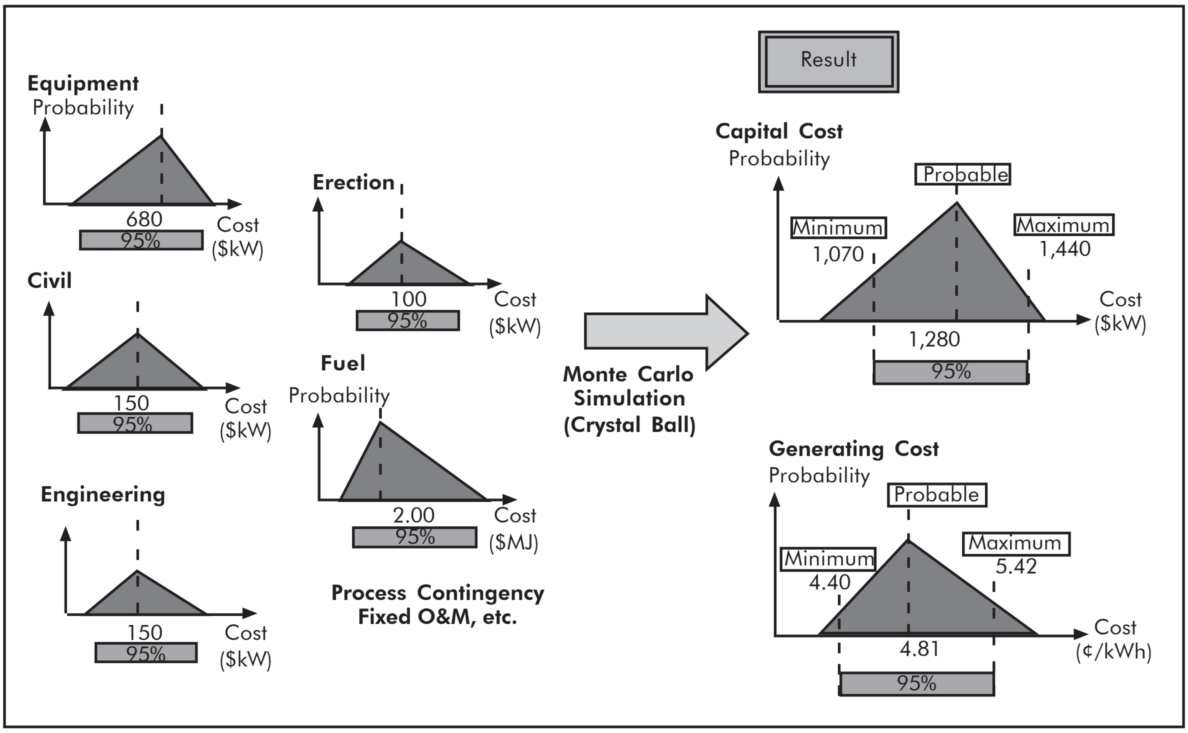
Any future-oriented economic assessment must account for uncertainties in the key input variables. Key uncertainties in projecting future generation costs include fuel costs, future technology cost and performance, resource variability and others. An uncertainty analysis was conducted using a probabilistic approach based on the "Crystal Ball" software package. All uncertainty factors are estimated in a band, and generating costs were calculated by Monte Carlo Simulation. A summary of the uncertainty analysis process is graphically presented in outputs from the "Crystal Ball" analysis including maximum, average and minimum levelized cost of electricity (Table 1.2).

Table 1.2: Uncertainty Variables for Analysis

		Distribution (Default Value)		
	Inputs	*Minimum*	*Probable*	*Maximum*
Common Conditions	Equipment			
	Civil			
	Engineering	Yr 2005-20%		Yr 2005 + 20%
	Erection	Yr 2010-25%	100%	Yr 2010 + 25%
	Contingency	Yr 2015-30%		Yr 2010 + 30%
	Fix O&M			
	Variable O&M			
Particular Conditions	Fuel Price	Oil, Gas: +100%, 35% Coal: +65%, -20%		
	Capacity Factor	CF for Renewable Technology (Solar-PV, Wind, PV-wind, Solar-thermal, Hydro): ± (2-10%)		

Note: Each distribution is cut with 95% reliability.

Example: Capital Cost of Coal IGCC (in 2015)



Capacity Factor

Capacity factor is the ratio of the actual energy generated in a given period relative to the maximum possible if the generator produced its rated output all of the time. Capacity factor is a key performance characteristic, as it expresses the productive output relative to the installed capacity and allows for capital costs to be expressed in levelized terms. We chose capacity factor rather than availability factor or other expressions of productive output per unit installed capacity because it is unambiguous and universally applicable.

Deployment Venue

Capital cost and operating costs for a given power generation technology can vary considerably depending on where the power plant is located. In order to simplify the economic assessment, we express all capital costs and operating costs on the basis that the power plant is constructed in India. This allows extrapolation of capital and operating costs to other deployment venues based on a comparison of available national or regional benchmarks (for example, labor rates and fuel delivery surcharges).

Fuel Price Forecasts

Fuel prices used throughout this report are based on the IEA World Energy Outlook 2005 forecast. We have levelized the forecast fuel price over the life span of each generating technology assessed, taking into account forecast average price. We incorporated price fluctuations by allowing a price range of up to 200 percent of forecast base fuel price. The resulting fuel price range for each time frame and each fuel is shown in Table 1.3.

Regional Adjustments

An objective of the assessment was to express all costing information (capital costs and generating costs) for the 22 power generation options on the same basis, including assumed location and fuel supply arrangements. However, all infrastructure capital and operating costs – engineering, equipment and material, construction, O&M, fuel, even contingency – vary depending on location. A particularly area-sensitive cost variable is labor, which is an important determinant of both construction and O&M costs.

Table 1.3: Fossil Fuel Price Projections

Crude Oil				
				US$/bbl (US$/GJ)
FOB Price of Crude Oil		*2005*	*2010*	*2015*
Crude Oil (Dubai, Brent, WTI)	Base	53 (9.2)	38 (6.6)	37 (6.5)
	High	–	56 (9.8)	61 (10.6)
	Low	–	24 (4.2)	23 (4.0)
Coal				
				US$/ton (US$/GJ)
FOB Price of Coal		*2005*	*2010*	*2015*
Coal (Australia)	Base	57 (2.07)	38 (1.38)	39 (1.42)
	High	–	53 (1.92)	56 (2.04)
	Low	–	30 (1.10)	30 (1.10)
Natural Gas				
				US$/MMBTU (US$/GJ)
FOB Price of Natural Gas		2005	2010	2015
Gas (U.S., European)	Base	7.5 (7.1)	5.1 (4.8)	5.1 (4.8)
	High	–	7.0 (6.6)	7.6 (7.2)
	Low	–	4.0 (3.8)	3.3 (3.1)

Note: "–" means no cost needed.

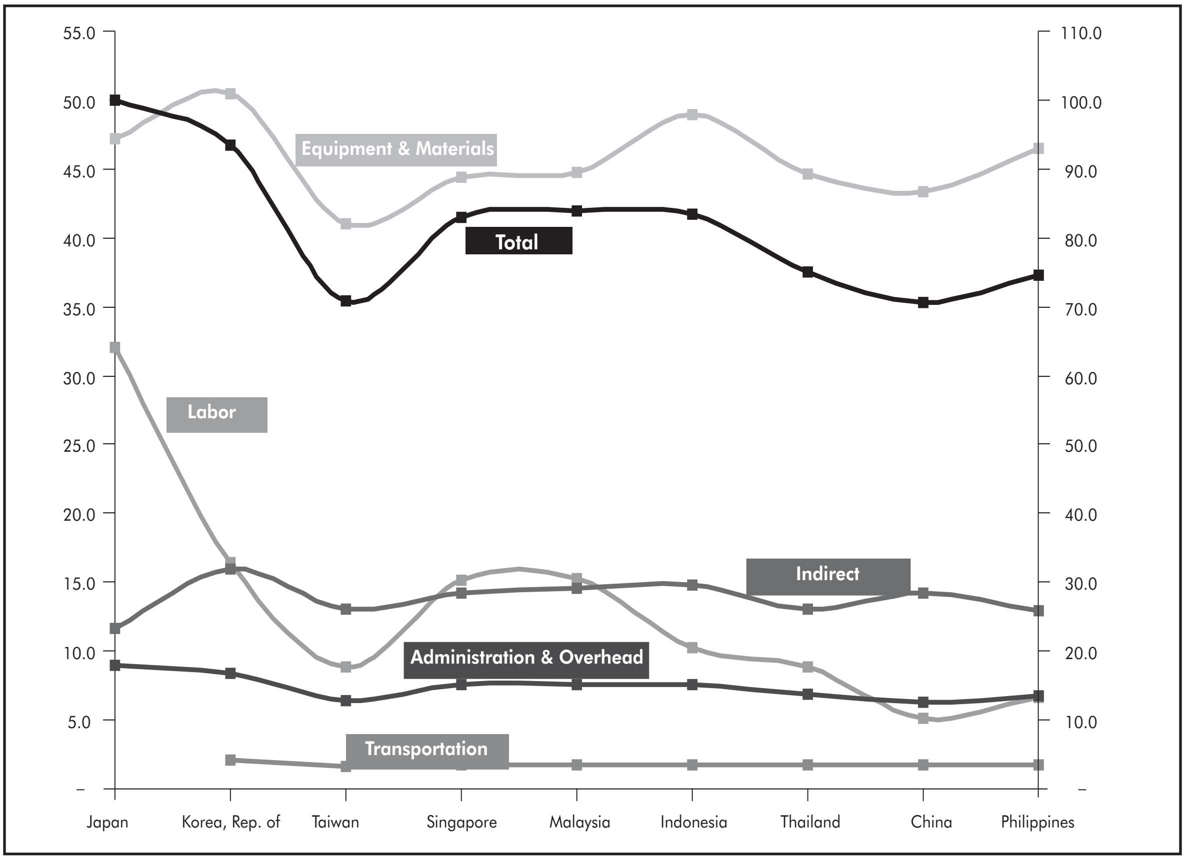
Location factors for the Asian region are provided in Figure 1.1. In addition to the data presented for developing countries, we also provide data for one industrial economy (Japan). The data shown in Figure 1.1 suggest that the variation in costs of engineering, equipment and materials is quite small when procurement is done under the international competitive bidding (ICB) or comparable guidelines. The labor costs vary from region to region, depending on the gross domestic product (GDP) and per capita incomes.[5]

Study Limitations

This study is limited in several ways. First, it is time-bound. It does not reflect new technology developments or new secular trends that have emerged since the terms of reference were

[5] *Useful references on this topic include: http://www.cia.gov/cia/publications/factbook, http://hdr.undp.org/reports/global/2003, http://www.worldfactsandfigures.com/gdp_country_desc.php, http://stats.bls.gov/fls/hcompsupptabtoc.htm, http://www.ggdc.net/dseries/totecon.html, and http://www-ilo-mirror.cornell.edu/public/english/employment/strat/publ/ep00-5.htm.*

Figure 1.1: JSIM Labor Factor by Region



Source: Japan Society of Industrial Machinery Manufacturers, 2004.

formalized. At the same time, unpredictable fluctuations of generation facilities' prices caused by an excessive unbalance in demand-supply condition are not considered. Secondly, it is bound by the available literature. We drew from secondary sources and performed no new technology or analytic development. In some cases, especially with emerging technologies, available literature or project experience is limited. Thirdly, the results are generalized and represent averaging over what are important specific conditions (although the uncertainty analysis accounts for this somewhat). Any application of these results must be done based on modification to suit local, actual conditions.

2. Power Generation Technology Assessment

This section presents the detailed technology descriptions and results of the technical and economic assessment for 22 selected off-grid, mini-grid and grid electrification technology applications. The technology descriptions are presented in three groups – renewable power generation technologies, conventional power generation technologies and emerging power generation technologies.

Renewable Technologies

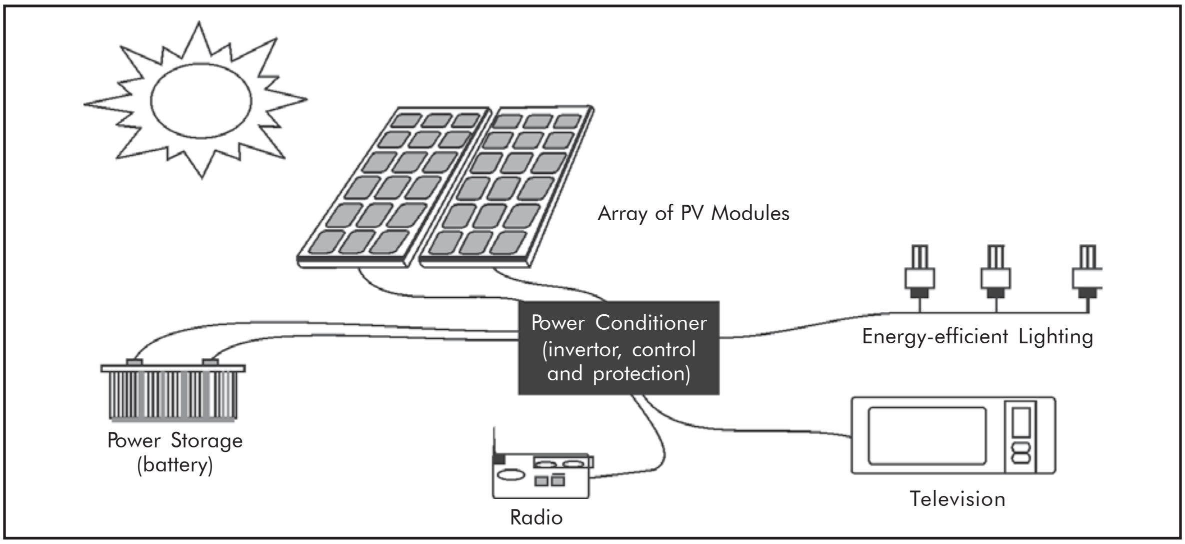
Six major renewable energy technologies (RETs) are reviewed in this study – solar photovoltaic (SPV), wind electric, solar thermal electric, geothermal electric, biomass electric and hydroelectric. Within each of these broad categories, there are one, and sometimes several configurations corresponding to combinations, permutations (including size) and hybrid arrangements of the individual technologies.

Solar Photovoltaic Power Systems

SPV systems utilize semiconductor-based materials (solar cells) which directly convert solar energy into electricity. First developed in the 50s, SPV technology has steadily fallen in price and has gained many niche applications, notably as satisfying remote power needs for telecommunications, pumping and lighting. SPV systems have many attractive features, including modularity, no fuel requirements, zero emissions, no noise and no need for grid connection. SPV systems can be classified according to three principal applications (Figure 2.1):

- Stand-alone solar devices purpose-built for a particular end use, for example, cathodic protection, home power and water pumping;
- Small solar power plants designed to provide village-scale electricity; and
- Grid-connected SPV power plants.

Figure 2.1: Stand-alone Solar Photovoltaic System



Source: *DOE/EPRI.*

For the economic assessment, we chose several common SPV configurations and sizes suitable for a range of off-grid, mini-grid and grid applications (Table 2.1).

Table 2.1: Solar PV Configurations Assessed

Description	*Small SPV Systems*		*SPV Mini-grid Power Plants*	*Large Grid-connected SPV Power Plant*
Module Capacity	50 W_p	300 W_p	25 kW	50 MW
Life Span Modules	20 Years	20 Years	25 Years	25 Years
Life Span Batteries	5 Years	5 Years	5 Years	NA
Capacity Factor	20%	20%	20%	20%

Note: NA = Not applicable.

Our economic assessment assumes a 20 percent capacity factor, based on 4.8 daily hours of peak power output. As SPV module costs comprise 50+ percent of the costs, we note that these costs have fallen from US$100 per W_p in 1970 to US$5 in 1998.[6] Our economic assessment assumes continued decreases in SPV costs of 20 percent between 2004 and 2015 based on technology advancement and growing production volume (Table 2.2).[7] Japan, one of the major markets for solar PV and a major manufacturer of SPV modules, is

[6] *The challenges of cold climates PV in Canada's North, Renewable Energy World, July 1998, pp 36-39.*
[7] *SPV sales have increased from 200 MW in 1999 to 427 MW in 2002 and to above 900 MW in 2004.*

forecasting production cost reductions from 100 yen (¥)/W_p today to ¥75/W_p by 2010 and ¥50/W_p by 2030. The solar PV industry in Europe and the United States is targeting costs of US$1.5-2.00/$W_p$ within 10 years, based on technological improvements as well as a growth in production volumes of 20-30 percent.

Table 2.2: Targets for SPV Future Costs

Cost	*Europe*	*United States*	*Japan*	*India*
2004 SPV Module Costs	€5.71/W_p	US$5.12/$W_p$	¥100/W_p	Rs 150/W_p
Target Cost in 2010	€1.5-2/W_p	US$1.5-2/$W_p$	¥75/W_p	Rs 126/W_p*(@2.75/W_p)
Expected Cost in 2015	€0.5/W_p	NA	¥50/W_p (in 2030)	Rs 92/W_p* (US$2/$W_p$)

Note: NA = Not applicable.

Wind Power Systems

Wind turbines are classified into two types: small (up to 100 kW) and large. Small wind turbines are used for off-grid, mini-grid and grid-connected applications, while large wind turbines are used exclusively for grid-connected power supply. Wind turbine components include the rotor blades, generator (asynchronous/induction or synchronous), power regulation, aerodynamic (Yaw) mechanisms and the tower. Wind turbine component technology continues to improve, including the blades (increasing use of C epoxy and other composite materials to improve the weight/swept area ratio); generators (doubly-fed induction generators and direct-drive synchronous machines providing improved efficiency over broader wind speed ranges); power regulation (through active stall pitch controls); and towers (tubular towers minimize vibration, allow for larger machines to be constructed and reduce maintenance costs by providing easier access to the nacelle).

The major applications for small wind turbines are charging batteries and supplying electrical loads in direct current (DC) (12 or 24 volts [V]), bus-based off-grid power systems. When configured with a DC alternating current (AC) inverter and a battery bank, the small wind turbine can deliver power to a village or district mini-grid, usually in a hybrid configuration with diesel generators or SPV.

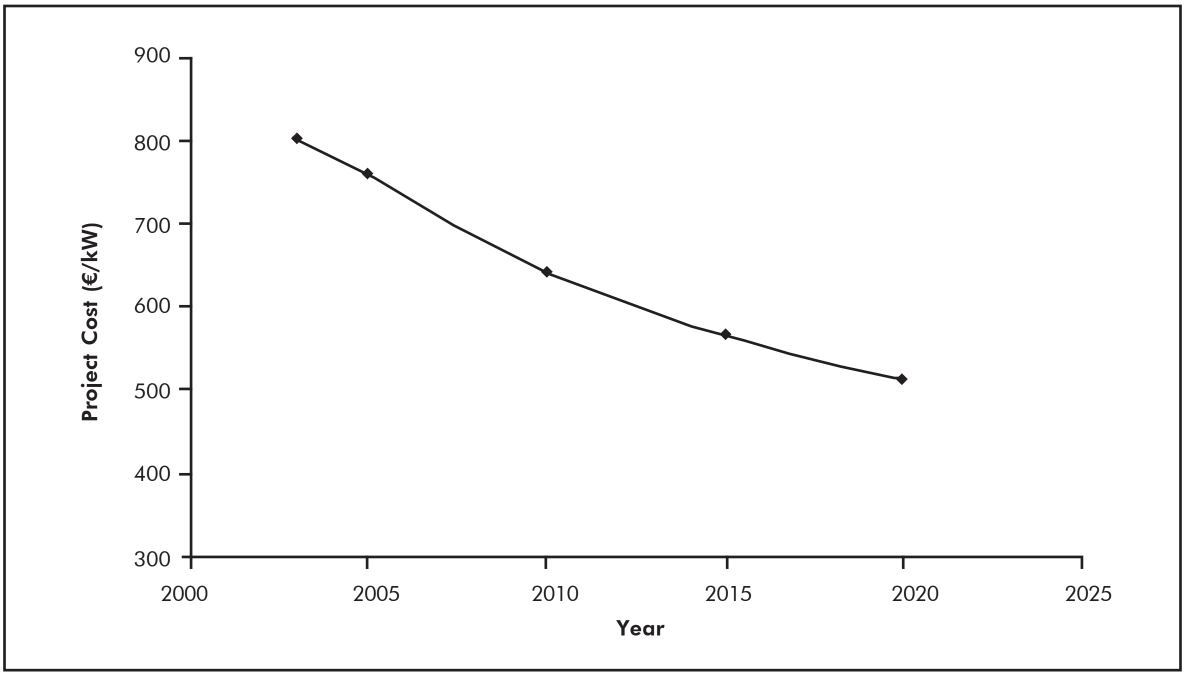
Design assumptions regarding wind turbines with output from 0.3 kW to 100,000 kW are shown in Table 2.3. Capacity factors depend on wind speeds at a given location and can vary from 20 percent to 40 percent. An average value of 25 percent is assumed with the uncertainty analysis incorporating the broader range of likely location-specific capacity factors.

Table 2.3: Wind Turbine Perfomance Assumptions

Capacity	*300 W*	*100 kW*	*10 MW*	*100 MW*
Capacity Factor (%)	25	25	30	30
Life Span (year)	20	20	20	20
Annual Gross Generated Electricity (MWh)	0.657	219	26,280	262,800

The costs of wind generators have been decreasing over the years, a trend which is forecast to continue (Figure 2.2). The Electric Power Research Institute (EPRI) projects the costs for 10 mega watt (s) (MW) plant will decrease by 10 percent in 2010 and 20 percent by 2015.[8] The EPRI values are likely conservative, as today's costs for large wind turbines in India, Germany, Denmark and Spain are in the 800 to 1,200 euros (€)/kW.[9] In our cost projections, we have elected to use the European cost projections as a lower bound and EPRI cost projections as an upper bound.

Figure 2.2: Projected Wind Power Costs, 2000-25



Source: European Wind Energy Association.

[8] *Renewable Energy Technical Assessment Guide – TAG-RE: 2004, EPRI, 2004.*
[9] *Wind Energy – The Facts, Vol. 2: Costs and Prices, EWEA, 2003.*

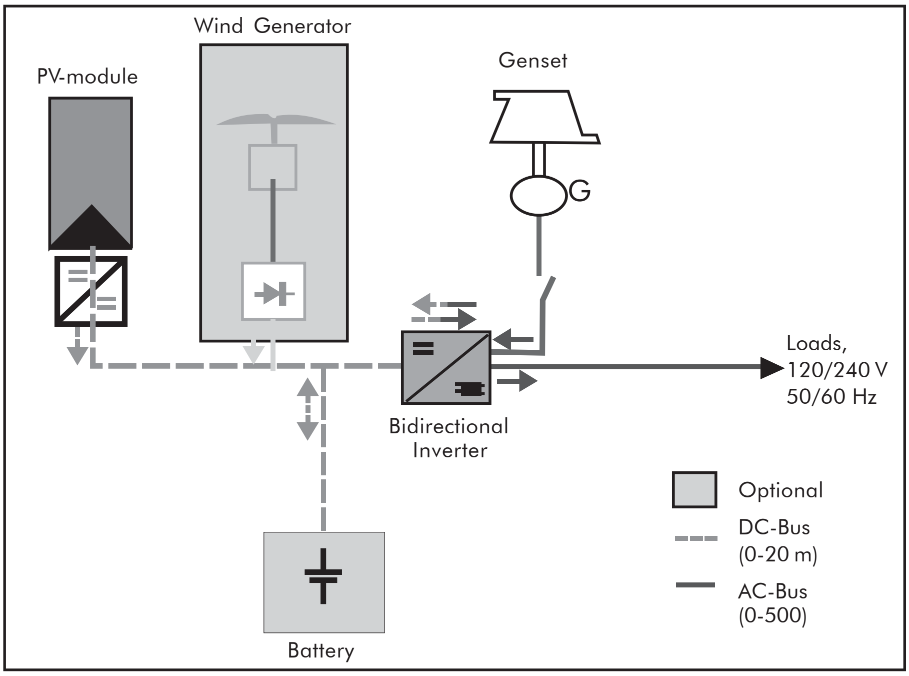
SPV-wind Hybrid Power Systems

Power generation schemes using a combination of SPV and wind energy can take advantage of the complementary availability of the solar and wind resources. A hybrid SPV-wind power configuration allows each renewable resource to supplement the other, increasing overall reliability without having to resort to other backup sources such as diesel generators. This is a potentially attractive arrangement for small loads (100 kW or less) in an off-grid or mini-grid configuration. Solar-wind hybrid systems have been successfully deployed for island mini-grids, remote facilities and small buildings.

SPV-wind hybrid systems, in practice, can be configured in two ways, depending on how the inverter/controller and battery storage are arranged. A common arrangement is an AC mini-grid with DC-coupled components (Figure 2.3). The inverter can receive both DC power from the SPV array and AC power from the wind turbine, and deliver these inputs to the battery storage. This configuration is effective for village applications (0.5 to 5 kW).

Another arrangement for larger loads (3 to 100 kW) is a modular AC system, which comprises a traditional AC system but incorporates inverters for battery storage and SPV power input. For the economic assessment of SPV-wind hybrids, we use a system life of 20 years, and a 30 percent capacity factor. Cost projections for these hybrid systems are assumed to follow the same trajectory as projected for the individual technologies (for example, SPV and wind). Two size ranges – 300 W, corresponding to an off-grid application and 100 kW, corresponding to a mini-grid application – are examined.

Figure 2.3: SPV-wind DC- and AC-coupled Arrangement

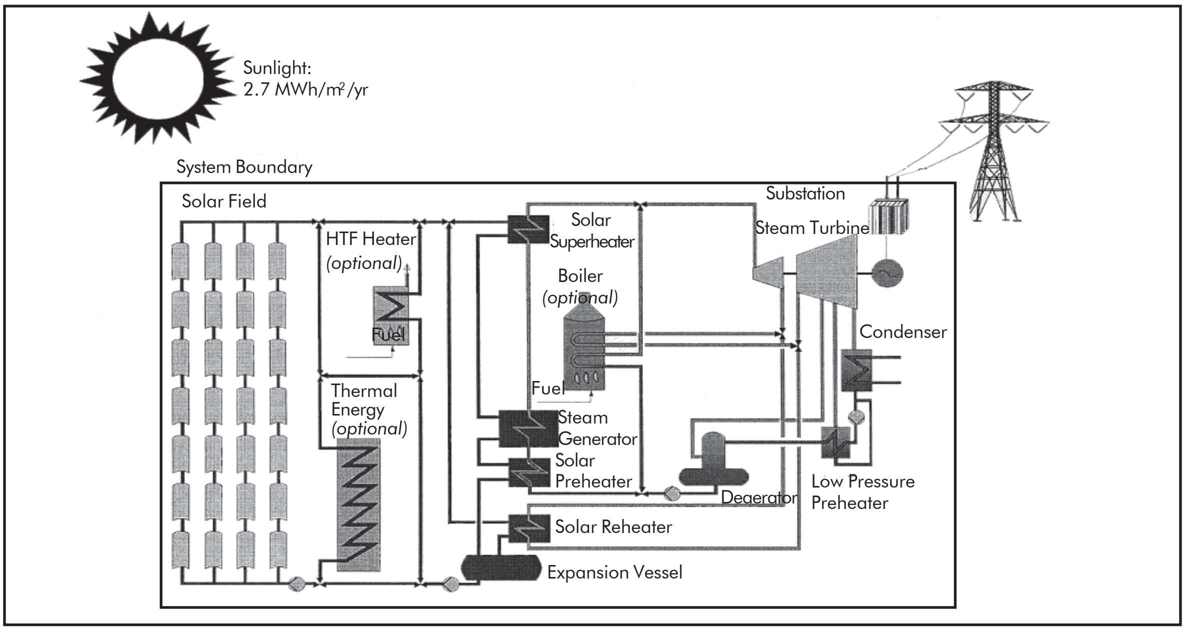


Source: DOE/EPRI.

Solar-thermal Electric Power Systems

Generating power from solar energy through thermal-electric power conversion requires collecting solar energy in concentrated densities sufficient to power a heat engine. Many solar energy concentrating schemes have been tried, including parabolic dish collectors, parabolic trough collectors and central receivers. Only the parabolic trough configuration has progressed toward commercial application, albeit slowly (Figure 2.4). There are several parabolic trough-based solar-thermal electric projects ranging from 10-50 MW in the planning stages, and this is the only solar-thermal electric system considered here.[10]

Figure 2.4: Solar-thermal Electric Power Plant



Source: DOE/EPRI.

A parabolic trough concentrator tracks the sun with a single-axis mechanical tracking system oriented east to west. The trough focuses the solar insolation on a receiver located along its focal line. The concentrators are deployed in numbers sufficient to generate the required amount of thermal energy, which is transported via a heat transfer fluid (typically high temperature oil) to a central power block, where the heat generates steam. The power block consists of steam turbine and generator, turbine and generator auxiliaries, feed-water and condensate system. A solar-thermal electric power plant, which incorporates thermal storage, can have a higher capacity factor, but at increased cost. Here we examine a grid-connected 30 MW solar-thermal electric power plant with and without thermal storage (Table 2.4).

[10] *See, for example, The World Bank Project Information Document, Arab Republic of Egypt Solar Thermal Power Project. Report No. AB662.*

Cost and performance estimates prepared by the United States Department of Energy's (USDoE) National Renewable Energy Laboratory (NREL) are used in the analysis. An NREL forecast of possible solar-thermal electric cost reductions, based on technology improvement projections and scale-up, projects a 15 percent cost reduction by 2010 and 33 percent by 2015. We take these projections as an upper bound and assume a more conservative cost reduction of 10 percent and 20 percent by 2010 and 2015, respectively.

Table 2.4: Solar-thermal Electric Power System Design Parameters

Capacity	*30 MW (without thermal storage)*	*30 MW (with thermal storage)*
Capacity Factor (%)	20	50
Life Span (year)	30	30
Gross Generated Electricity (GWh/year)	52	131

Source: NREL.

Geothermal Electric Power Systems

The principal geothermal resources under commercial development are naturally-occurring hydrothermal resources. Hydrothermal reservoirs consist of hot water and steam found in relatively shallow reservoirs. Hydrothermal reservoirs are inherently permeable, which means that fluids can flow out of wells drilled into the reservoir.

Commercial exploitation of geothermal systems in developing economies is constrained by availability of the resource, and the need for geothermal resource prospecting and exploitation capacity. Countries which have successfully developed geothermal power plants (the Philippines, Mexico, Indonesia, Kenya and El Salvador) tend to be in regions with many hydrothermal manifestations (for example, geysers, hot springs) and where there has been intensive local capacity-building, and an influx of needed specialists.

We assess geothermal power systems in three sizes – a 200 kW binary hydrothermal application suitable for mini-grid applications and two larger sizes (20 MW binary hydrothermal and 50 MW flash hydrothermal) suitable for grid applications. Table 2.5 provides design assumptions for these generic geothermal power plants while Figure 2.5 provides a schematic for a typical binary hydrothermal electric power plant.

Table 2.5: Design Assumptions for Geothermal Power Plants

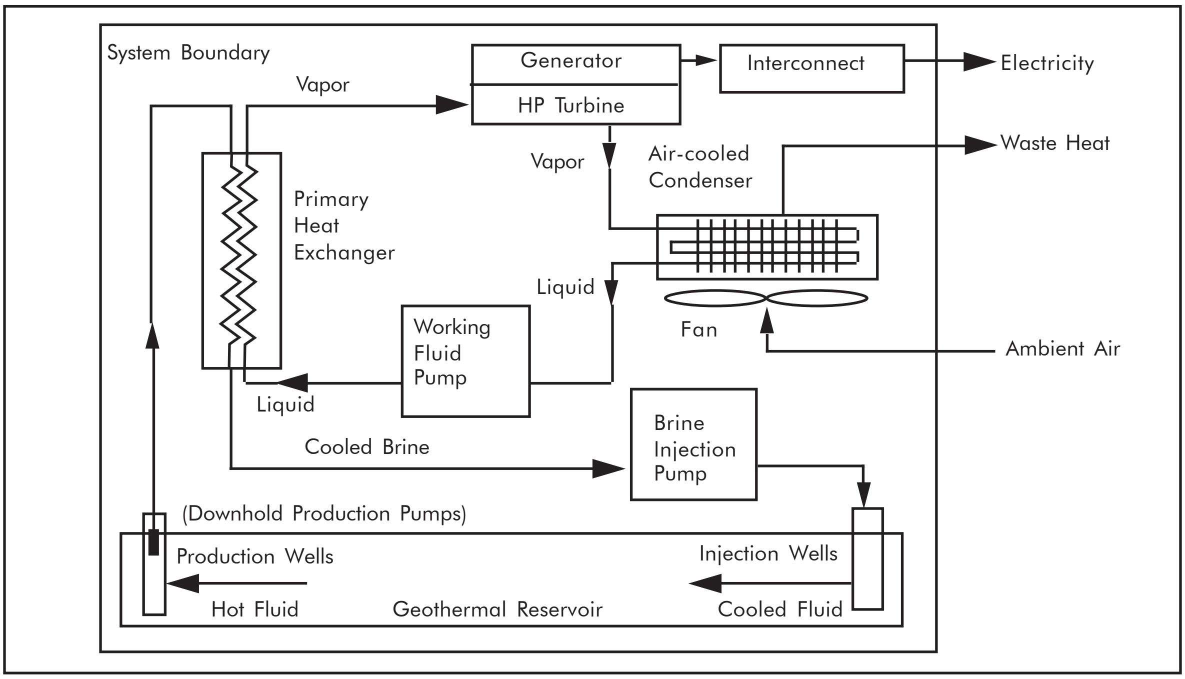
	Binary Hydrothermal	*Binary Hydrothermal*	*Flash Hydrothermal*
Capacity	200 kW	20 MW	50 MW
Capacity Factor (%)	70	90	90
Geothermal Reservoir Temperatures	125-170°C	125-170°C	>170°C
Life Span (year)*	20	30	30
Net Generated Electricity (MWh/year)	1,230	158,000	394,200

** Although the plant life span is 20-30 years, wells will be depleted and new wells be drilled much before that time. An allowance for this additional drilling is included in the generating cost estimates.*

Large geothermal plants operate as base-loaded generators with capacity factors comparable to conventional generation. Smaller plants for mini-grid applications will have lower capacity factors (30-70 percent), due mainly to limitations in local demand. Although geothermal power plants are renewable, they are not emission-free. Hydrogen sulfide (H_2S) emissions (no more than 0.015 kilograms (s) (kg)/MWh) are common, but can be mitigated with removal equipment. Carbon dioxide (CO_2) emissions compare favorably to fossil fuel plants.

Unlike most other RE resources, the extractive nature of geothermal projects results in longer development time and a particular project development cycle unlike that of other

Figure 2.5: Binary Hydrothermal Power Plant Schematic



Source: DOE/EPRI.

technologies assessed. Table 2.6 provides a breakdown of the capital cost estimates organized by the development sequence (for example, exploration, confirmation, main wells), showing that fully one-quarter of the capital costs is expended before ground is even broken on the geothermal power plant. For this reason, we assume extra contingency costs for this option.

Table 2.6: Geothermal Power Capital Costs by Project Development Phase (2004 US$)

Item	*200 kW Binary Plant*	*20 MW Binary Plant*	*50 MW Flash Plant*
Exploration	300	320	240
Confirmation	400	470	370
Main Wells	800	710	540
Power Plant	4,250	2,120	1,080
Other	1,450	480	280
Total	**7,200**	**4,100**	**2,510**

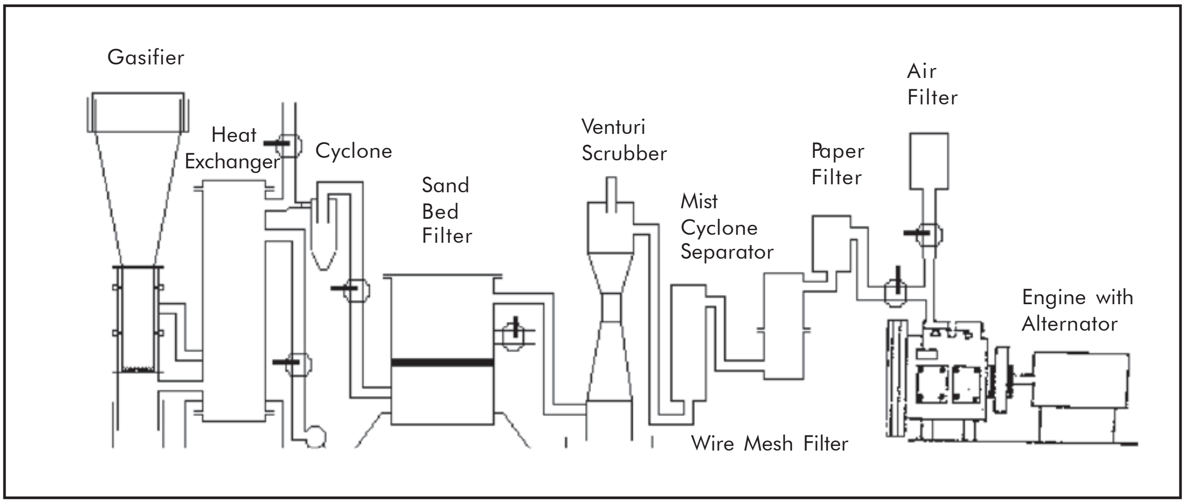
It is difficult to predict future prices for geothermal power systems. Although there have been significant long-term price declines since 1980 (about 2 percent per year for power plants), recent increases in oil prices have driven up the cost of geothermal wells. Many industry analysts contend that research and large-scale deployment can resume a downward trend in geothermal power costs. We assume a flat cost trajectory for this technology, and capture the potential for significant cost reductions in the uncertainty analysis.[11]

Biomass Gasifier Power Systems

A biomass gasifier converts solid biomass material (woody cellulose and other organic solids) into a combustible gas mixture known as "producer gas" with relatively low thermal value (1,000-1,100 (Kilo Calorie (s) [kcal]/Cubic Meter [m^3]). The gasification process involves successive drying, pyrolysis, oxidation/combustion and reduction in a staged chamber under different temperatures and pressures. The producer gas (containing 52 percent Nitrogen [N], 12 percent CO_2, 2 percent methane (CH_4), 20 percent carbon monoxide [CO] and 14 percent hydrogen [H]) is then filtered, scrubbed and treated before being combusted in a standard engine-generator configuration (Figure 2.6).

[11] *We draw from the EPRI work on RE to establish a range of expected capital cost reductions (generally, -20% and +10%) over the study period.*

Figure 2.6: Biomass Gasification Process Schematic



Types of gasifiers in use include down draft, updraft and cross draft, fluidized bed and pyrolyzers. Choice of gasifier design affects the thermal value of the produced gas and its inert contents (tar, ash, particulates, CO), as well as the amount of treatment necessary before it can be used. Fuel cost is the most important parameter in estimating the generation costs of any biomass-based power generation technology. The cost of biomass depends on many parameters, including project location, type of biomass feedstock, quantity required and present and future alternative use. We assess two sizes/applications of biomass gasifier technology – a small (100 kW) system applicable to mini-grid applications and a large (20 MW) system applicable to grid-connected use. Table 2.7 gives details of the design and performance parameters we assume for the economic assessment of these two cases.

Table 2.7: Biomass Gasifier Design Assumptions

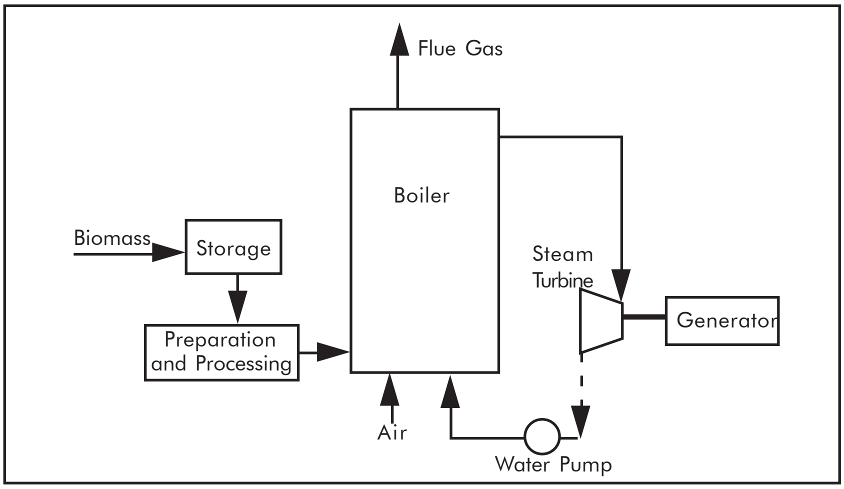
Capacity (kW)	*100 kW*	*20 MW*
Fuel	*Wood/Wood Waste/Agro Waste*	*Wood/Wood Waste/Agro Waste*
Calorific Value of Fuel	4,000 kcal/kg	4,000 kcal/kg
Capacity Factor	80%	80%
Producer Gas Calorific Value	1,000-1,200 kcal/Nm^3	1,000-1,200 kcal/Nm^3
Life Span of System	20 Years	20 Years
Specific Fuel Consumption	1.6 kg/kWh	1.5 kg/kWh

Environmental impacts associated with combustion of the biomass gas are assumed to be constrained by emissions control regulation, consistent with the World Bank standards. The future cost of these systems will likely be less than at present, as biomass gasification has considerable potential for technology improvements and economies of mass production. Our economic assessment assumes that improvements in the areas of low tar-producing gasifiers and improved cleaning and cooling equipment will yield a 5 percent reduction in capital costs by 2010, and a 10 percent reduction by 2015.

Biomass-steam Electric Power Systems

A biomass-steam electric power system is for the most part indistinguishable from other steam electric power systems (for example, oil and coal) that combust fuel in a boiler to generate steam for power production. A biomass-fired boiler generates high-pressure steam by direct combustion of biomass in a boiler. There are two major types of biomass combustion boilers – pile burners utilizing stationary or traveling grate combustors and fluidized-bed combustors. A schematic diagram of direct-fired biomass electricity generating system is shown in Figure 2.7.

Figure 2.7: Biomass-fired Steam Electric Power Plant



In a pile burner combustion boiler, the biomass burns on a grate in the lower chamber, releasing volatile gases which then burn in the upper chamber. Current biomass combustor designs utilize high efficiency boilers and stationary or traveling grate combustors with automatic feeders that distribute the fuel onto a grate to burn. Fluidized-bed combustors are the most advanced biomass combustors. In a fluidized-bed combustor, the biomass fuel is in a small granular form (for example, rice husk) and is mixed and burned in a hot bed of sand. Injection of air into the bed creates turbulence, which distributes and suspends the fuel while increasing the heat transfer and allowing for combustion below the temperature that normally creates nitrogen oxides (NO_x) emissions.

We assess only one biomass steam electric configuration – a 50 MW grid-connected power plant with a capacity factor and performance characteristics comparable to that of a conventional central station power plant (Table 2.8).

Table 2.8: Biomass-steam Electric Power Plant Design Assumptions

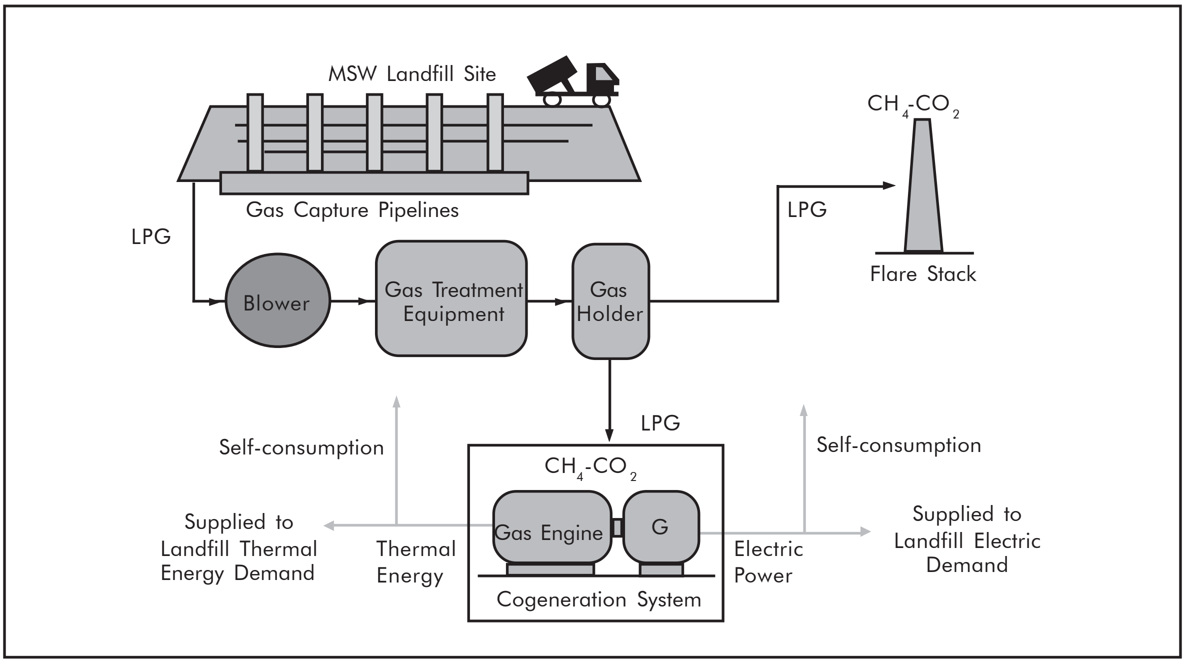
Capacity	*50 MW*
Capacity Factor (%)	80
Fuel	Wood/Wood Waste/Agro Waste
Calorific Value of Fuel	4,000 kcal/kg
Specific Fuel Consumption	1.5 kg/kWh
Life Span (year)	20
Gross Generated Electricity (GWh/year)	350

A biomass-steam electric power plant will have emission characteristics similar to that of any other fossil fuel-fired plant, other than SOs. Environmental impacts are assumed to be constrained by emissions control regulation, consistent with the World Bank standards. The future costs for biomass-steam generation projects are expected to drop as a result of increased market penetration and technology standardization. Our assessment assumes a modest reduction of 3 percent by 2010, and 5 percent by 2015. The key uncertainty in estimating biomass-based power generation technology is the cost of biomass, which depends on many parameters including location, type of biomass feedstock, quantity required and present and future alternative use.

Municipal Waste-to-power via Anaerobic Digestion System

Municipal waste can be converted to electric power in two ways: (i) by mass burning in a waste-to-energy facility; or (ii) through anaerobic digestion (AD) of the organic fraction of solid waste, either in closed digesters or, in situ, in landfills. The biogas product of AD comprises CH_4, CO_2 , H and traces of H_2S. The biogas yield and the CH_4 concentration depend on the composition of the waste, and the chemical and collection efficiency of the anaerobic digester or landfill design. After treatment to remove undesirable trace gases, the biogas can be used for thermal applications or in gas engines to generate electricity. Our economic assessment will be of a waste-to-power system in which biodegradable matter is anaerobically digested in a landfill (Figure 2.8).

Figure 2.8: Municipal Waste-to-power via Anaerobic Digestion



Source: Ministry of Environment, Government of Japan.

We examine only one configuration, that of a large (5 MW), grid-connected waste-to-energy power plant with performance parameters as shown in Table 2.9.

Table 2.9: Municipal Waste-to-power System Characteristics

Capacity	*5 MW*
Capacity Factor (%)	80
Fuel-type	Municipal Solid Waste
Life Span (year)	20
Gross Generated Electricity (GWh/year)	35

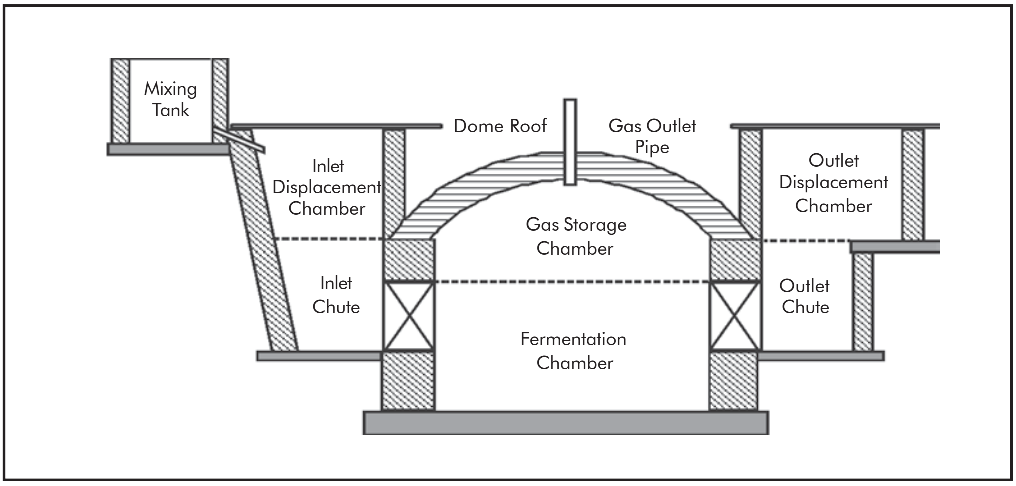
Environmental impacts of the digestion process should be minimal, as any H_2S or other organic volatiles can be scrubbed before utilization of the biogas product. Waste-to-energy projects have highly desirable net Greenhouse Gas (GHG) impacts, as CH_4 emissions that might otherwise emanate from landfill sites are sequestered.

We project a decrease in both capital and generating costs of waste-to-power systems in future, as significant reductions are likely from technological development and domestic manufacture of plant equipment. We assume these trends will result in a decrease in equipment cost of 15 percent by 2015. Other uncertainties including any "tipping costs" for the waste material are included in the uncertainty analysis.

Biogas Power Systems

A biogas electric power system operates in a manner similar to the municipal waste-to-power system described above, with biomass feedstock in the form of animal dung, human excreta and leafy plant materials anaerobically digested to produce a highly combustible biogas comprising 60 percent CH_4 and 37 percent CO_2, with traces of sulfur dioxide (SO_2) and 3 percent H. A 25-kg batch of cow dung digested anaerobically for 40 days produces 1 m^3 of biogas with a calorific value of 5,125 kcal/m^3. The remaining slurry coming out of the plant is rich in manure value and is a valuable fertilizer. Typical biogas constructions include the floating drum-type and the fixed dome-type (Figure 2.9). Both configurations have inlet and outlet chutes and a digester which operates at a constant gas pressure throughout, that is, the gas produced is delivered at the point of use at a predetermined pressure. The output of the biogas plant can be used for cooking or any other thermal application.

Figure 2.9: Fixed Dome Biogas Plant



The simplicity and modularity of design, construction and operation and the variety of uses for the biogas product, make this technology well suited for small-scale applications. Therefore, our economic assessment focuses on a biogas system sized to provide sufficient power for a 60 kW engine operating in a mini-grid application. We assume a capacity factor of 80 percent, which is achieved by properly sizing the plant and ensuring sufficient feedstock into the biogas system (Table 2.10).

Table 2.10: Biogas Power System Design Assumptions

Capacity	*60 kW*
Capacity Factor (%)	80
Life Span (year)	20
Gross Generated Electricity	0.42 GWh

As with the other biomass applications, the GHG impacts are highly positive, as the design sequesters and utilizes CH_4 that would otherwise escape to the atmosphere. Since biogas technology is very simple, uses local resources and has been in commercial operation for a long time, we do not project any dramatic reduction in future system costs.

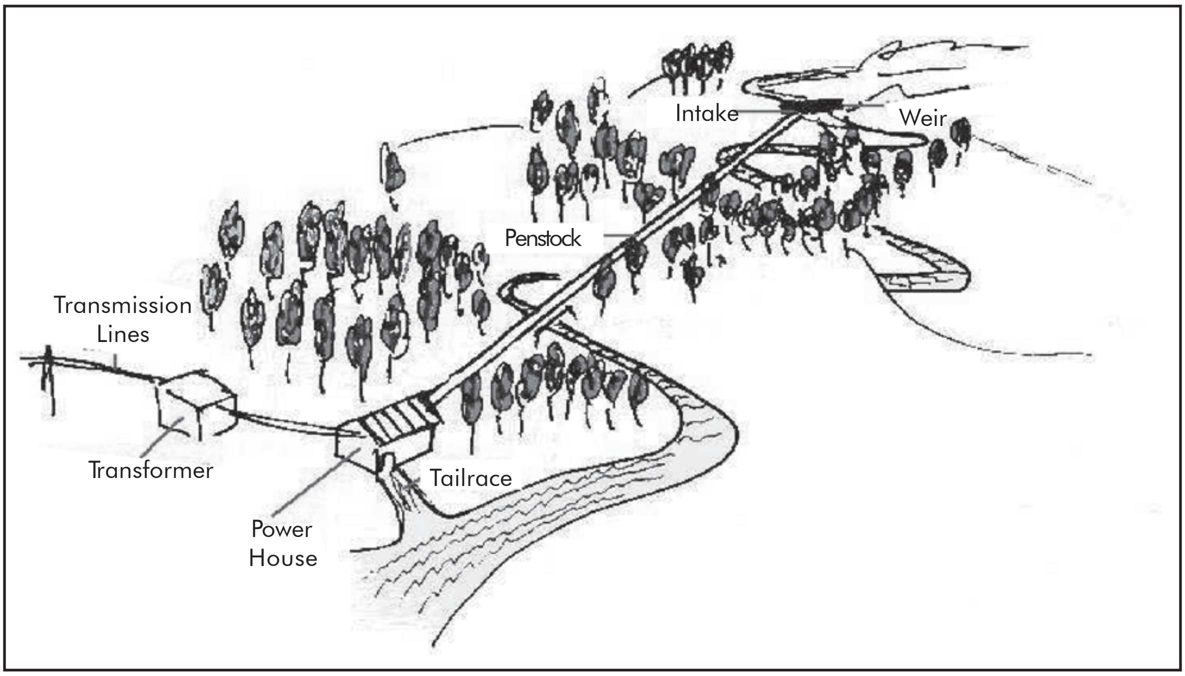
Micro- and Pico-hydroelectric Power Systems

Micro-hydro power projects are usually "run-of-the-river" (RoR) schemes that divert some of the water flow through civil works, for example, an intake weir, fore bay, and, for micro-hydro options, a penstock. Such schemes require no water catchments or storage, and thus have minimal environmental impacts. A drawback of such a scheme is seasonal variation in flow, making it difficult in some cases to balance load with power output. Because micro- and pico-hydro systems are simple, scaleable, reasonably reliable and low cost, they provide a source of cheap, independent and continuous power without the need for environmental safeguards.

A micro-hydroelectric power plant comprises civil works and electro-mechanical equipment. Civil works include the weir, which provides a regulated discharge to the feeder channel; the feeder channel, constructed of concrete with desilting tanks along its length; the fore bay, a concrete or steel tank designed providing a steady design head for the project; and the penstock, a steel, concrete or PVC pipe, sized to provide a steady and laminar water flow into the turbine (Figure 2.10). The electro-mechanical works include a Pelton or Turgo turbine (for high-head applications) or a Kaplan or Francis turbine (for low-head applications); an induction or synchronous generator (induction for low power outputs and synchronous for large-capacity units); and an electronic load governor or electronic load controller, depending on whether the turbine and generator operate at full power or varying load conditions.

A pico-hydroelectric power plant is much smaller than a micro-hydro (for example, 1 kW or 300 W), and incorporates all of the electro-mechanical elements into one portable device. A pico-hydro device is easy to install, with 300 W-class pico-hydroelectric units typically

Figure 2.10: Micro-hydroelectric Power Scheme



Source: http://www.microhydropower.net.

installed by the purchaser because of the low 1-2 meters (m) head requirement, while larger (1 kW) units require a small amount of construction work to accommodate somewhat higher (5-6 m) head requirements. They are typically installed on the river or stream embankment and can be removed during floods or low flow periods. The power output is sufficient for a single house or small business. Earlier pico-hydro devices were not equipped with any voltage or load control, which was a drawback as it produced lighting flicker and reduced appliance life. Newer pico-hydro machines come with embedded power electronics to regulate voltage and balance loads.

For our economic assessment, we chose three design points – a micro-hydro scheme of 100 kW suitable for a mini-grid application and two pico-hydro schemes (1 kW and 300 W) suitable for off-grid applications (Table 2.11). As with other renewable power systems, capacity factor varies according to site conditions and loading. We assume an average capacity factor and incorporate wider variations in the uncertainly analysis.

There has been very little variation in the equipment cost of micro- and pico-hydro electric equipment. Our economic assessment assumes that the capital costs will decline by less than 5 percent over the study period. Our uncertainty analysis attempted to account for wide variations in capacity factor depending upon the availability of hydro resource and the quality of the sizing and design process.

Table 2.11: Micro- and Pico-hydroelectric Power Plant Design Assumptions

Capacity	*300 W*	*1 kW*	*100 kW*
Capacity Factor (%)	30	30	30
Source	River	River	River
Life Span (year)	5	15	30
Gross Generated Electricity (kWh/year)	788	2,628	26,2800

Mini-hydroelectric Power Systems

Mini-hydroelectric power schemes are "RoR" schemes using the same design principles and civil and electro-mechanical components as micro-hydro schemes. Mini-hydro technology is well established around the world and has found favor with private investors. The systems are simple enough to be built locally at low cost and have simple O&M requirements, which gives rise to better long-term reliability. These systems provide a source of cheap, independent and continuous power, without degrading the environment. Our economic assessment envisions a larger (5 MW) mini-hydro project developed for a large mini-grid or grid-connected application, as shown in Table 2.12. A properly-sited, well-designed mini-hydro project should have a capacity factor of 45 percent on an average.[12]

Table 2.12: Mini-hydroelectric Power Plant Design Assumptions

Capacity	*5 MW*
Capacity Factor (%)	45
Source	River
Life Span (year)	30
Gross Generated Electricity (GWh/year)	19.71

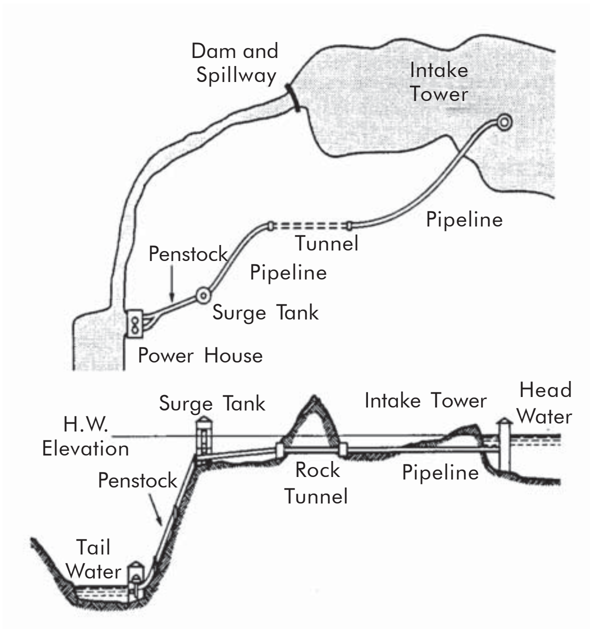
The capital cost of mini-hydro projects is very site-specific and can range between US$1,400/kW and US$2,200/kW. The probable capital cost is US$1,800/kW. The equipment cost for mini-hydroelectric schemes has not changed over the past five years; therefore, we project only modest equipment cost declines over the study period.

[12] *Based on several sources: (i) inputs from Alternate Hydro Energy Centre (AHEC), Roorkee; (ii) small hydro power (SHP): China's Practice – Prof Tong Jiandong, Director General, International Network for Small Hydro Power (IN-SHP); and (iii) Blue AGE Report, 2004 – A strategic study for the development of Small Hydro Power in the European Union, published by European Small Hydro Association (ESHA).*

Large Hydroelectric and Pumped Storage Power Systems

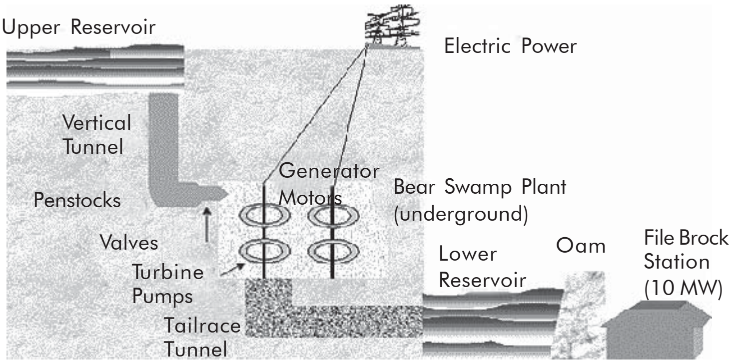
Unlike mini-, micro- and pico-hydro schemes, large hydroelectric projects typically include dams and water catchments in order to ensure a very high capacity factor consistent with the high construction cost of these facilities. The distinguishing characteristic of large hydroelectric and large pumped storage projects is the dam design, which is highly site-specific and can be of four general categories – gravity, concrete, earth or other fill and arch concrete. The water intake system determines the amount of pressure head and how water flows to the turbines. Dams with hydroelectric turbines located at the dam site obtain their head from the surface level of the reservoir. The hydroelectric power plants are installed directly under the dam, which allows effective use of water and no need for a feed channel. A conduit water intake system introduces the flow to the hydroelectric turbine via a feed channel and penstock (Figure 2.11).

Figure 2.11: Conduit-type Intake Arrangement for Large Hydroelectric Power Plant



A pumped storage power generation scheme is a specialized scheme in which several power plants are used to optimize the power output in accordance with diurnal variation in system, load. In this scheme the hydroelectric power plant acts both as a generator and a pump, allowing water in a lower reservoir to be pumped up to upper reservoir during the low-load overnight period, and then generating electricity during peak load periods (Figure 2.12).

Figure 2.12: Pumped Storage Hydroelectric Power Arrangement



We assess two cases – a 100 MW conventional hydroelectric facility and a 150 MW-pumped storage hydroelectric facility. Design characteristics and performance parameters for the two cases are shown in Table 2.13.

Table 2.13: Large Hydroelectric Power Design Assumptions

	Large Hydroelectric	*Pumped Storage Hydroelectric*
Capacity	100 MW	150 MW
Capacity Factor (%)	50	10
Turbine-type	Francis	Francis Reversible Pump-turbine
Generation System	Pondage	Pumped Storage
Life Span (year)	40	40

There can be significant environmental and socioeconomic impacts associated with construction and operation of large hydroelectric power systems, which our assessment does not try and capture. It is imperative to investigate, predict and evaluate the potential environmental and other impacts, and to take sufficient safeguard measures to prevent them or incorporate the costs into the economic assessment process. Potential environmental and social impacts including sediment transport and erosion, relocation of populations, impact on rare and endangered species, loss of livelihood and passage of migratory fish species in hydro power plants.[13]

[13] *References for the World Bank environmental assessment and social safeguard guidelines include: http: web.worldbank.org/WBSITE/EXTERNAL/TOPICS/ENVIRONMENT/EXTENVASS 0,,menuPK: 407994~pagePK:149018 ~piPK:149093~theSitePK:407988,00.html and http://web.worldbank.org/WBSITE/EXTERNAL/PROJECTS/EXTPOLICIES/ EXTSAFEPOL 0,,menuPK:584441~pagePK:64168427~piPK:64168435~theSitePK:584435,00.html.*

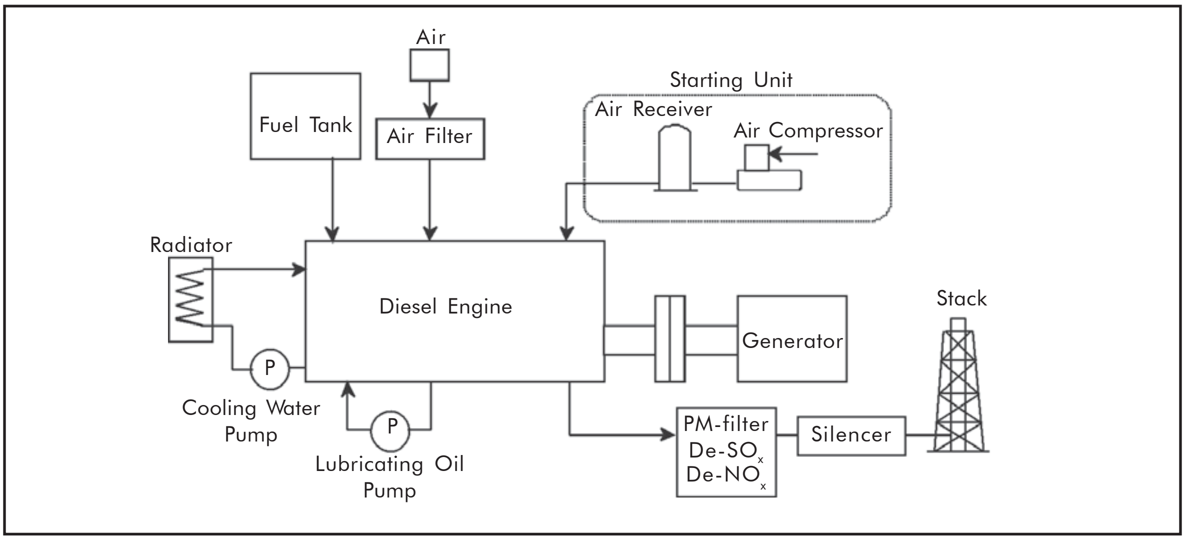
Conventional Power Generation Systems

This section summarizes conventional power generation systems of all sizes, including distributed generation technologies such as diesel/gasoline engines and utility-scale power plants including oil and gas-fired combustion turbines (CTs), steam and combined cycle power plants and coal-fired electric technologies.

Diesel/Gasoline Engine-generator Power Systems

Diesel and gasoline engines can accommodate power generation needs over a wide range, from several hundred W to 20 MW. Features including low initial cost, modularity, ease of installation and reliability have led to their extensive use in both developed and developing countries. A typical configuration is an engine/generator set, where the shaft output of a gasoline or diesel engine drives an electrical generator, usually via a clutch or similar mechanism. Gasoline engine generator sets are portable and easy to install and operate, but are relatively expensive to operate. A diesel generator has a higher efficiency (35-45 percent), and can use a range of fuels including light oil, residual oil and, even, palm or coconut oil. Diesel engines also have a wide capacity range, from 2 kW to 20 MW. A line diagram for a typical diesel generator is shown in Figure 2.13.

Figure 2.13: Diesel-electric Power Generation Scheme



We have chosen four generic gasoline/diesel engine-generator arrangements in order to assess their economic effectiveness across a range of power supply configurations: (i) a 300 W and a 1 kW gasoline engine-generator configured for off-grid use; (ii) a 100 kW diesel engine configured for mini-grid use; and (iii) a 5 MW diesel engine generator configured for grid connection. The type of engine and fuel reflect the commonly available commercial products. The design and operating parameters for each case are shown in Table 2.14.

Table 2.14: Gasoline and Diesel Engine-generator Design Assumptions

	300 W (off-grid)	*1 kW (off-grid)*	*100 kW (mini-grid)*	*5 MW (grid)*
Capacity Factor (%)	30	30	80	80/10
Engine-type	Gasoline	Gasoline	Diesel	Diesel
Fuel-type	Gasoline	Gasoline	Light Oil	Residual Oil
Thermal Efficiency (Gross, LHV, %)	13	16	38	43
Life Span (year)	10	10	20	20
Generated Electricity (GWh/year)	0.0008	0.003	0.7	35.0/4.4

Diesel engines have significant air emissions and require emissions control equipment (Table 2.15). These costs are included in the diesel generator economic assessment.

Table 2.15: Emission Characteristics of Diesel Generators

	Emission Standard	*Gasoline Engine*		*Diesel Engine*	
		300 W	*1 kW*	*100 kW*	*5 MW*
PM	50mg/Nm^3	Zero	Zero	80-120	100-200
SO_x	2000mg/Nm^3 (<500MW:0.2tpd/MW)	Very Small	Very Small	1,800-2,000	4,400-4,700
NO_x	Oil: 460	1,000-1,400[14]		1,600-2,000	
CO_2	g-CO_2/net-kWh	1,500-1,900		650	

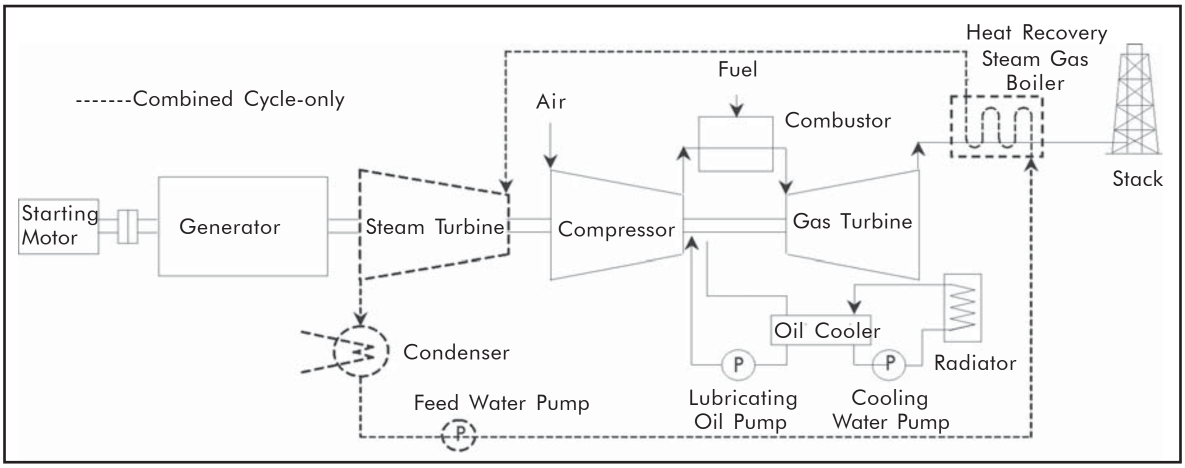
Combustion Turbine Power Systems

Oil and Gas Combustion Turbines (CT) and Combined Cycle Gas Turbine (CCGT) power plants are considered together, as both utilize gas turbines burning natural gas or

[14] *Smallest gasoline engines emit NO_x beyond the World Bank's standard; however, it is not realistic to add removal equipment to these small generators. Thus, this cost is not included.*

light/residual oil. CTs are desirable for power applications because of their quick start-up capability, modularity (1 MW-10 MW), small footprint and low capital cost. Gas turbines can be used for emergency power or for remote loads; however, they require high quality fuels and have high O&M requirements. A CCGT combines a combustion turbine cycle(s) with a steam turbine to form a multicycle system. For our assessment, we focus on a 300 MW CCGT power plant combining a super-high temperature (1,300 [celsius] °C) gas turbine with two bottom-cycles using the 300°C and 600°C waste heat out of the combustion turbine (Figure 2.14). This approach boosts the overall thermal efficiency from 36 percent for a CT to 51 percent for a CCGT.

Figure 2.14: Combined Cycle Gas Turbine Schematic



For the economic assessment, we focus on two common configurations, both suited for grid-connected operation. For the CT, we assume only a 10 percent capacity factor, reflecting a typical peak loading application. For the CCGT, we assume a combination of base load operations and load following (Table 2.16).

Table 2.16: CT and CCGT Design Assumptions

	Combustion Turbine	*Combined Cycle*
Capacity	150 MW	300 MW
Capacity Factor (%)	10	80
Thermal Efficiency (gross, LHV, %)	34	51
Life Span (year)	25	25

Combustion turbines burning light oil or gas have very low air emissions other than NO_x and, thus, emission control equipment costs are nominal. There is an expectation of capital cost reductions for these technologies due to mass production and technological development; the economic assessment assumes that capital cost decrease 7 percent from 2004 to 2015.

Coal-steam Electric Power Systems

Coal-steam electric power plants typically have a pulverized coal (PC) boiler where coal is combusted, creating steam which passes through a turbine to generate electricity (Figure 2.15).

Figure 2.15: Coal-fired Steam-electric Power Plant

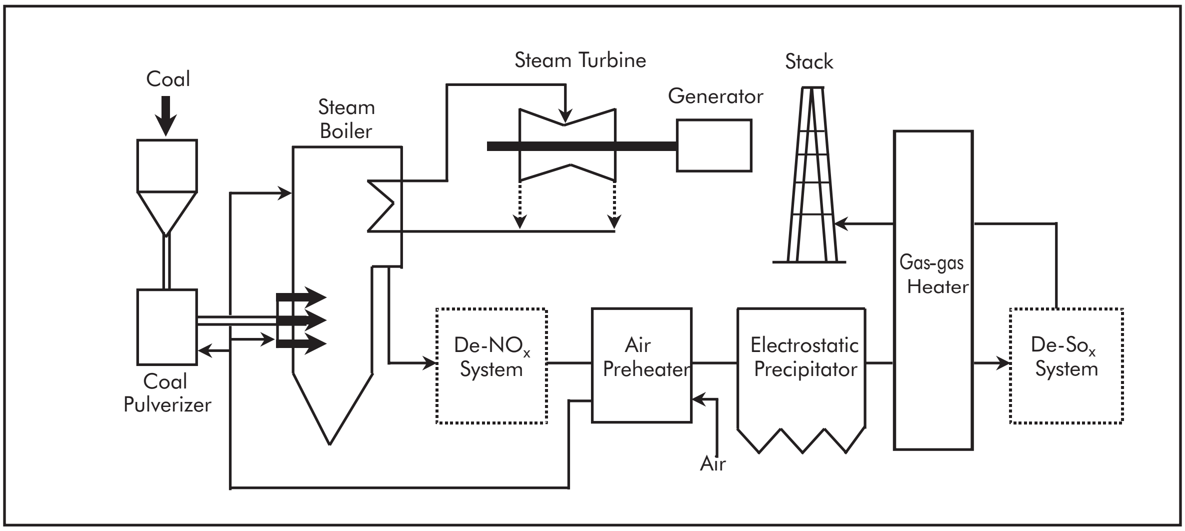


Table 2.17 shows design parameters and operating characteristics for a typical steam-electric power plant. We assume a 300 MW base-loaded plant with a SubCritical boiler.

Table 2.17: Coal-fired Steam-electric Power Plant Design Assumptions

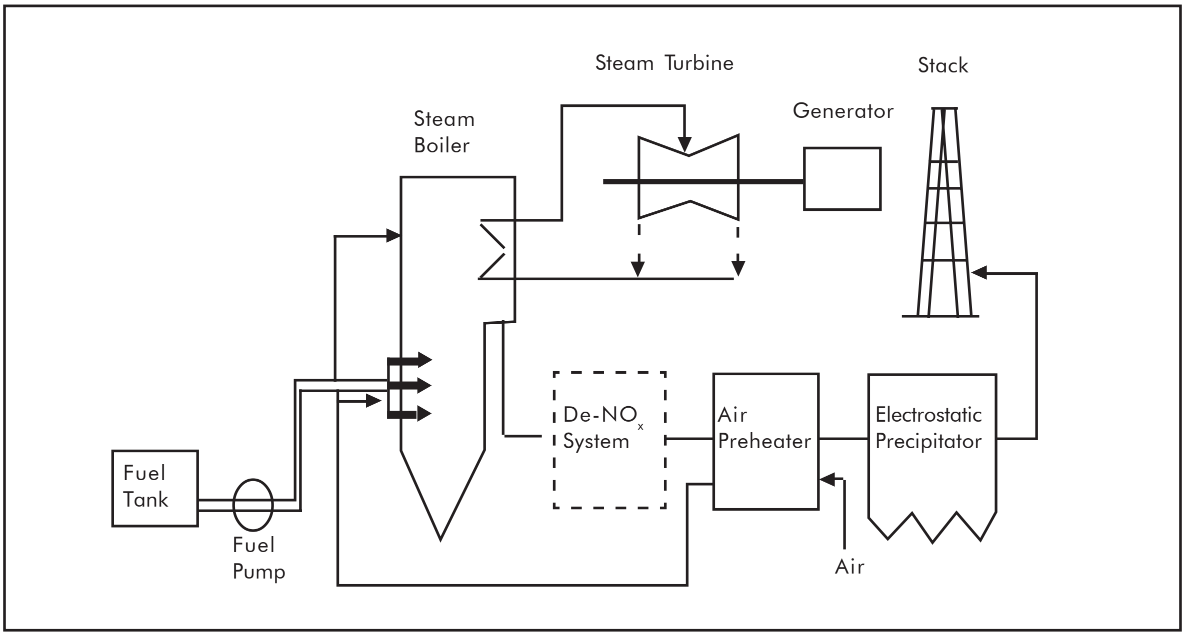
Capacity	*300 MW*		*500 MW*	
Boiler-type	PC SubCritical	PC SubCritical	PC SuperCritical	PC UltraSuperCritical
Thermal Efficiency (gross, LHV, %)	41	42	44	47
Capacity Factor (%)			80	
Life Span (year)			30	

Thermal performance has been increased mainly by the adoption of progressively higher steam conditions and there are currently more than 600 SuperCritical (SC) boilers in operation worldwide. Although pressures have increased well into the SC range, design steam temperatures of subcritical plants have normally been set at 540^{0}C (1,005^{o}fahrenheit[F]). This level is chosen to minimize the use of high chrome (austenitic) steels, particularly for high-temperature section components. The adoption of new high strength ferritic steels has recently enabled the steam conditions to be raised above 25 MPa, 566^{0}C (1,050^{0}F), with the current maximum boiler outlet steam temperature being about 593^{0}C (1,100^{0}F) to 600^{0}C (so-called "UltraSuperCritical [USC]" conditions). Further development of advanced materials is the key to even higher steam conditions and major development projects are in progress, particularly in Denmark, Germany, Japan and the United States. Plants with main steam conditions of up to 35 MPa and up to 650^{0}C (1,200^{0}F) are foreseen in a decade, giving an efficiency approaching 50 percent.

Oil-fired Steam-electric Power Systems

Oil-fired steam-electric power plants were in common use until the oil price shocks of the 70s. High oil costs and availability of newer, more efficient technologies has resulted in less use of this technology. An oil-fired steam-electric power plant schematic is shown in Figure 2.16. In this system, the heat generated in the oil-fired boiler is turned into steam and it generates electricity using a steam turbine.

Figure 2.16: Oil-fired Steam-electric Power Plant



For the economic assessment, we chose a large, grid-connected base-load unit (300 MW), with operating characteristics as shown in Table 2.18.

Table 2.18: Oil-fired Steam-electric Power Plant Design Assumptions

Capacity	*300 MW*
Capacity Factor (%)	80
Fuel-type	Residual Oil
Thermal Efficiency (gross, LHV, %)	41
Life Span (year)	30

An oil-fired power plant sited in India burning residual fuel oil will emit significant sufficient particulate matter (PM) to require an ESP but will not require any sulfur oxides (SO_x) or NO_x controls (Table 2.19).

This is a very mature technology and no appreciable cost reductions or performance improvements are expected.

Table 2.19: Emissions from Oil-fired Steam-electric Power Plants

	Emission Standard for Oil	*Result*		*Reduction Equipment*
		Boiler Exhaust	*Stack Exhaust*	
SO_x	2,000 mg/Nm^3 (<500 MW:0.2tpd/MW)	1,000 mg/Nm^3 (20 tpd)	←	Not Required
NO_x	460 mg/Nm^3	200 mg/Nm^3	←	Not Required
PM	50 mg/Nm^3	300 mg/Nm^3	50 mg/Nm^3	Required
CO_2	–	670 g-CO_2/kWh	←	–

Note: "–" means no cost needed.

Emerging Power Generation Technologies

We also review and assess four promising new power generation technologies – coal integrated gasification combine cycle (IGCC), coal atmospheric fluidized bed combustion (AFBC), microturbines and fuel cells. The first two technologies have considerable potential for large grid-connected applications, while the latter two have considerable modularity which may make them attractive in mini-grid applications.

Coal IGCC Power Systems

An IGCC power plant gasifies coal to produce a synthesis gas which can be fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a turbine. Power is produced from both the gas and steam turbine generators. By removing the emission-forming constituents from the synthetic gas, an IGCC power plant can meet extremely stringent emission standards. Figure 2.17 shows a typical configuration for a coal-fired IGCC power plant as considered in this study. Table 2.20 provides the design parameters and operating characteristics assumed for the 300 MW coal-fired IGCC power plant assessed here.

IGCC power plants are capable of removing 99 percent of Sulfur (S) in the fuel as elemental S; hence the S emissions are extremely low. The high pressure and low temperature of combustion also drastically mitigates NO_x formation. IGCC technology is very new, thus the cost of these plants will not decrease significantly over the term of this study.

Figure 2.17: Coal-fired IGCC Power Plant Arrangements

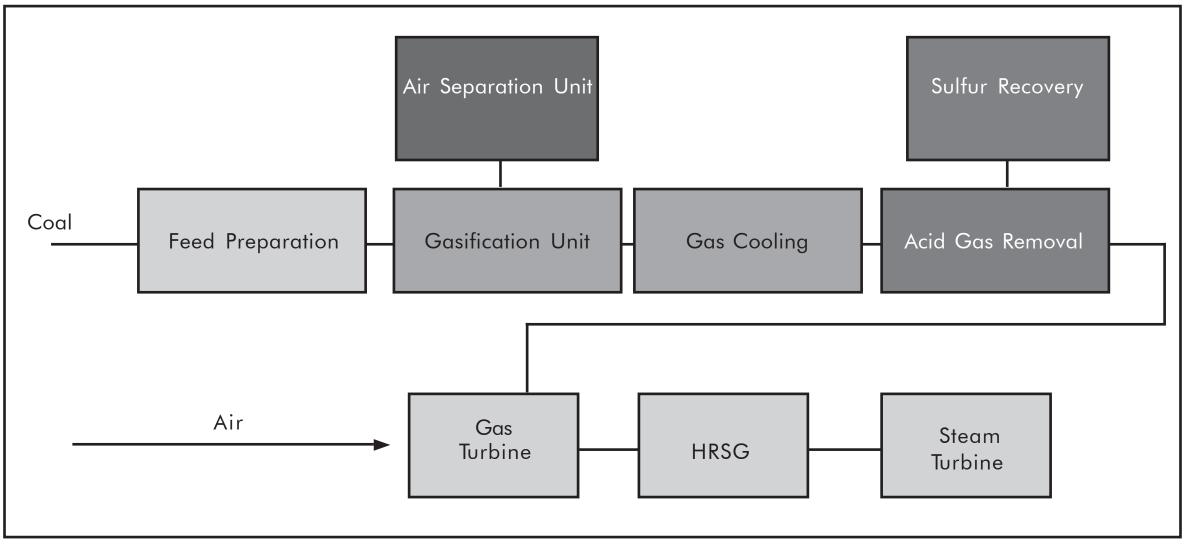


Table 2.20: Coal-fired IGCC Power Plant Design Assumptions

Capacity	*300 MW*	*500 MW*
Efficiency (gross, LHV, %)	47	48
Capacity Factor (%)	80	
Life Span (year)	30	

Coal-fired AFBC Power Systems

In AFBC, limestone is injected into the combustion zone to capture the S in the coal. The calcium sulfate ($CaSO_4$) by-product (formed from the combination of SO_2 and the CaO in the limestone) is captured and can be easily disposed along with the fly ash from combustion (Figure 2.18). AFBC boilers are similar in design and operation to conventional PC boilers and utilize the same Rankine steam cycle. AFBC boilers can efficiently burn low reactivity, low-grade and high-ash fuels, which may not be burned in conventional PCs. For the economic assessment of coal-fired AFBC systems, we assumed a large, base-loaded power plant of 300 MW utilizing a subcritical steam cycle. Table 2.21 compare the emission results for this AFBC design with the World Bank emission standard.

Table 2.21: Emission Results for a Coal-fired AFBC Power Plant

	The World Bank Emission Standard for Coal	*Emissions Calculated for a Coal-fired AFBC Design Located in India*
SO_x	2000 mg/Nm^3 (<500MW: 0.2 tpd/MW)	940 mg/Nm^3 [15]
NO_x	750 mg/Nm^3	250 mg/Nm^3 [16]
PM	50 mg/Nm^3	Under 50 mg/Nm^3 [17]

AFBC technology is expected to be used widely in the future, mainly in new power plant applications. Costs are expected to decline, especially in developing countries such as China and India.

Microturbine Power Systems

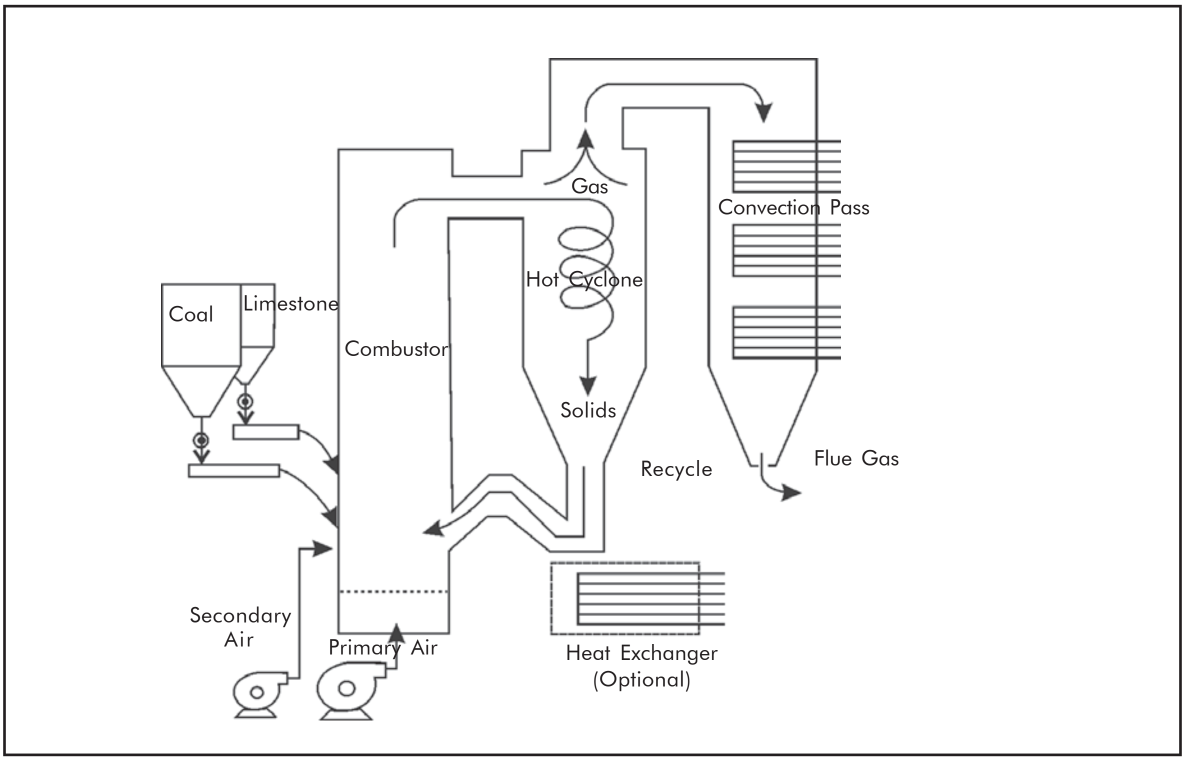
Microturbines are small, very efficient Brayton cycle turbine engines that can run on a range of fuels including natural gas, gasoline, diesel or alcohol. Microturbines are very high-speed devices (up to 120,000 resolutions per minute [RPM]) with quick starting capability, low noise, low NO_x emissions and the flexibility to be configured as combined heat and

[15] *Many solid fuels such as Indian coal contain CaO in the ash and are capable of capturing SO_2 without the addition of limestone. If the S in the coal is relatively low and/or the environmental standards are not very strict, limestone may not be required.*

[16] *Lower than 100 mg/Nm^3 (typically 30-50 mg/Nm^3) is possible with the addition of SNCR (selective noncatalytic reduction) system in the AFBC boiler.*

[17] *This depends on the design of the ESP or fabric filter; in some developing countries higher particulates (for example, 100 or 150 mg/Nm^3) may be allowed. In this case, the capital costs may be slightly lower (for example, US$10-15/kW)).*

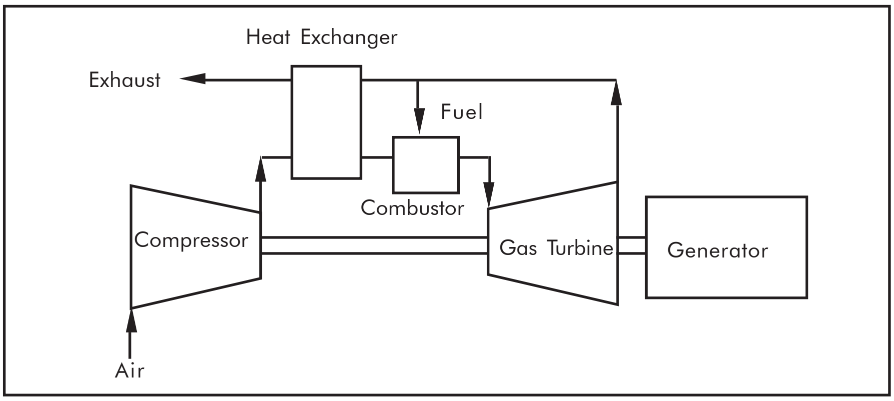
Figure 2.18: Coal-fired AFBC Boiler Schematic



Source: The World Bank.[18]

power (CHP) devices with overall thermal efficiencies approaching 60 percent. The basic layout of a micro-turbine is identical to that of a larger scale simple cycle or closed cycle gas turbine plant (Figure 2.19).

Figure 2.19: Gas-fired Microturbine Schematic



[18] *"The Current State of Atmospheric Fluidized-bed Combustion Technology," Washington, DC: The World Bank, Technical Paper # 107, Fall 1989.*

For the economic assessment, we focus on a larger microturbine with operating characteristics as shown in Table 2.22 and configured for electricity production in a mini-grid.

The environmental impacts of microturbines are extremely low and no emission control equipment is required. This technology is rapidly evolving and the two leading manufacturers (Elliot and Capstone) are promising a 50 percent reduction in capital costs (from US$1,500/kW to US$500/kW) within 20 years. Our assessment assumes a 4 percent annual capital cost reduction over the study period.

Table 2.22: Gas-fired Microturbine Design Assumptions

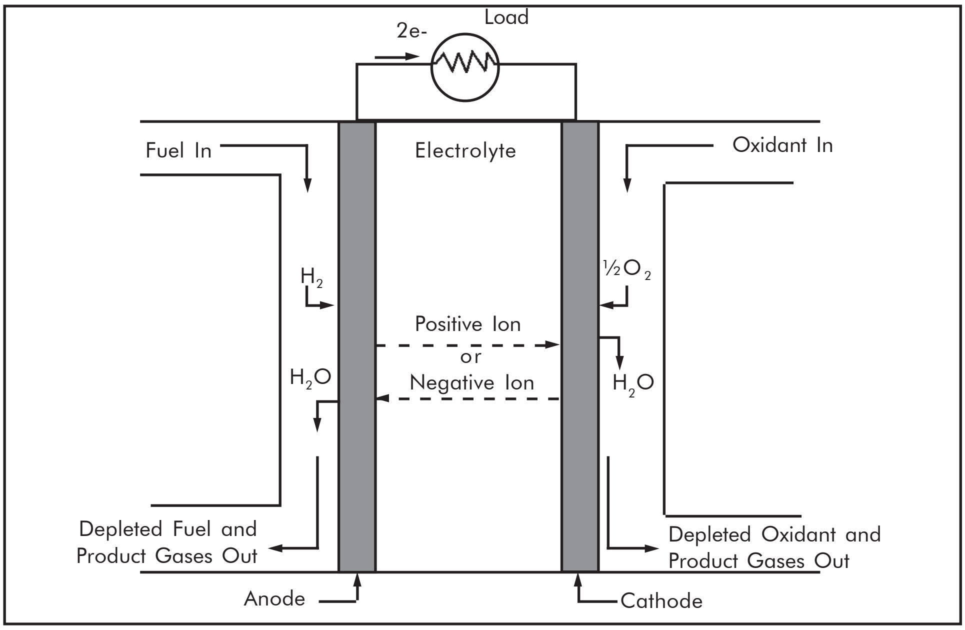
Capacity	*150 kW*
Capacity Factor (%)	80
Fuel-type	Natural Gas
Thermal Efficiency (LHV, %)	30
Life Span (year)	20

Fuel Cell Power Systems

Fuel cells operate through an electrochemical process in which H and air pass through a reactor, producing power and harmless by-products (Figure 2.20). This technology is in the early stages of commercialization (some 200 devices have been installed to date) and there are several competing cell designs including polymer electrolyte fuel cell (PEFC), phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC) and solid oxide fuel cell (SOFC). Fuel cells can be configured to suit the load requirements and installations of 200 kW to 11 MW are in service. The MCFC design, rated at 300 kW, is considered ready for commercialization.

We will assess two fuel cell configurations (Table 2.23), one for mini-grid applications and one for small grid-connected applications.

Figure 2.20: Operation of a Fuel Cell



Source: U.S. DOE Office of Fossil Energy NETL, 2000.

Table 2.23: Fuel Cell Power System Design Assumptions

	200 kW Fuel Cell	*5 MW Fuel Cell*
Capacity	200 kW	5 MW
Capacity Factor (%)	80	80
Fuel-type	Natural Gas	Natural Gas
Electrical Efficiency (LHV, %)[19]	50	50
Life Span (year)	20	20

Fuel cells have essentially negligible air emission characteristics, although they do produce CO_2 in approximately the same amounts as a gas-fired power plant. Fuel cell manufacturers expect significant performance improvements and capital cost reductions as this new technology is commercialized. Our economic assessment assumes reductions of 20 percent by 2010 and 40 percent by 2015.

[19] *Operating fuel cells as a combined heat and power (CHP) plant can increase fuel cell plant efficiency to 70 percent.*

3. Technical and Economic Assessment of Power Delivery

Unless located in an off-grid or premise-scale application, power generation technologies are deployed as part of an integrated electricity grid or an electrically-isolated mini-grid. The grid serves to transport the electric power from the generator to the customer via high-voltage, long-distance transmission and low-voltage distribution networks. This Chapter briefly describes the requirements for transmitting and distributing electricity production to end users, and discusses grid integration issues associated with certain renewable power generation technologies.

Power delivery requirements and associated costs derive entirely from the specific power system configuration. Table 3.1 summarizes the power delivery requirements and indicative associated levelized costs, inclusive of capital costs, O&M costs and technical losses, for the four power generation configurations considered in this study. The balance of this section provides more detail on the technical and economic characteristics of power delivery.

Table 3.1: Power Delivery Requirements According to Generation Configuration

	Grid-connected			
	Large	*Small*	*Mini-grid*	*Off-grid*
Typical Generator Size (kW)	50-300 MW	5-50 MW	5 kW-250 kW	0.3-5.0 kW
Annual Output	1,000 GWh	35 GWh	1 GWh	0.005 GWh
Transmission Costs	~US¢0.25/kWh (100 km circuit)	~US¢0.5/kWh (20 km circuit)	None	None
Distribution Costs	None	None	~US¢1-7/kWh	None

Transmission and Distribution Facilities

Nominal distribution voltages vary between 100 and 1,000 V for secondary distribution (sometimes called reticulation) and between 10 kV to 35 kV for primary distribution.[20] Most distribution networks limit voltages to no more than 35 kV for safety reasons. Installation standards, materials and components differ between each country, but every distribution system comprises three basic elements – poles, wires and transformers.

Nominal transmission voltages are between 35 kV and 230 kV; typical voltages used in developing countries include 66/69 kV, 110/115 kV and 220/230 kV (Table 3.2).

Table 3.2: Transmission Voltages in Developing Countries

	Countries	*Typical Voltages*
Africa	Algeria	220, 150, 90, 60
	Malawi	132, 66
	Senegal	225, 90, 30
	Tanzania	220, 132, 66
	Tunisia	225, 150, 90
Asia	Cambodia	230, 115
	India	220, 230, 132, 110, 33
	Lao PDR	230, 115, 35, 22
	Mongolia	220, 110, 35
	Myanmar	230, 132, 66
	Philippines	230, 138, 115, 69
	Vietnam	220, 110

As with the distribution network, transmission facilities mainly comprise wires, poles or steel towers, and transformers, albeit all at larger sizes to accommodate larger power flow and higher voltages.

[20] *See IEC 60038.*

Operations and Maintenance Requirements

Transmission and distribution (T&D) equipment must be regularly maintained to operate in the manner intended and with the life span promised by the manufacturer. T&D equipment may also require repair of damage caused by storms or accidents (for example, vehicles hitting power poles). A good rule of thumb is that O&M costs for a power delivery system should run between 1/8 and 1/30 of capital cost on an annual basis.[21] The lifetime of a grid is considered to be around 20-30 years for depreciation purposes, but can be more than 50 years with proper maintenance.[22]

Power Delivery Losses

Losses in electric power output from generator to customer can vary from 10 percent in a well-designed and maintained power grid to 25 percent or more (Table 3.3). As a

Table 3.3: Power Delivery Loss Rates in Selected Countries

Country or Region	*T&D Loss (%)*	*Fiscal Year*	*Source*
Cambodia	22.6	1998	EDC
Chubu Region (Japan)	4.9	2003	CEPCO Annual Report
India	31.42	1999	Indian Power Planning Committee Annual Report (2001/2002)
Karnataka State (India)	31.69	2002-03	KPTCL Data http://www.kerc.org/english/index.html
Kenya	16.2	1997	Overseas Japan Electric Power Investigation Committee (2000)
Lao PDR	24	2000	Overseas Japan Electric Power Investigation Committee (2000)
Malawi	14.8	1999	ESCOM Annual Report (1999/2000)
Philippines	14.4	2001	NPC Annual Report MERALCO Annual Report
Tanzania	11.9	1996	ESKOM Statistical Yearbook
Tunisia	11.2	1998	STEG
Vietnam	14.5	2000	Fifth Electric Power Master Plan (EVN)
Zimbabwe	10.8	1997	Annual Report
Average	**17.2**	–	–

Note: "–" means no cost needed.

[21] *Distributed Power Generation, Willis, H.L., and Scott, W.G.*
[22] *This, of course, will vary by equipment-type and construction and the operating conditions, including temperature, humidity, exposure to corrosives, etc.*

general rule, distribution losses account for more than two-third of the total power delivery losses. Losses are higher at the distribution level because resistance losses in conductors are proportional to the square of the electric current I2A. Since lower distribution voltages translate into higher current flows, the distribution system is inherently less efficient.

Economic Assessment of Power Delivery

A detailed formulation of the cost equations is provided in the CD-ROM (see Annex 2) to this report. Here we provide an overview of the approach and summary results. We assume overhead line construction, reflecting rural electrification practice in developing economies, and use of international (IEC) standards for component choice and construction. We assume there are no environmental or social impacts of power transmission and delivery. As T&D technology is very mature, we do not project any cost reductions or performance improvements over the term of the assessment.

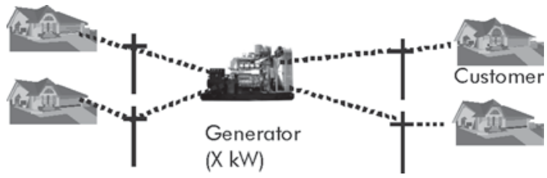
As with the calculation of generation costs, we convert the capital costs of T&D facilities into a levelized cost (US$/kWh) over the life span of the equipment and the volume of power delivered. Transmission costs and distribution costs can then be expressed simply as the sum of their respective levelized capital cost plus O&M costs plus the cost of losses.

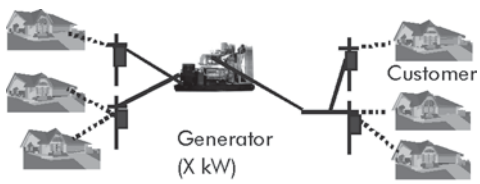
Distribution Costs

The capital cost of distribution facilities is proportional to both the circuit-kilometer of distribution conductor and the rated output of the generation source. Only a low-voltage distribution network is needed when the power station output is 60 kW or less, as loss reductions will be nominal unless the distribution circuit kilometers are very large. A power station output of 100 kW may require a higher voltage network with transformers, depending on factors such as customer density and size of the mini-grid. The capital cost formulation used here is shown in Figure 3.1.

A distribution capital cost calculation was performed for each power generation technology configured to serve a mini-grid. Actual installed distribution costs typical of Indian rural electrification programs were used (US$5,000 per circuit km for medium voltage (33 kV) and US$3,500/circuit-km for low-voltage reticulation (0.2 kV), along with US$3,500 per

Figure 3.1: Calculation Model for Distribution Costs

<table>
<tr><th colspan="2">Rated Output: X (kW)</th><th colspan="3">Image and Length of Distribution Line
(High-voltage Line:——, Low-voltage Line:·····, Transformer: ▮)</th></tr>
<tr><td colspan="2" rowspan="1">$X \leq 60$ kW
(No High-voltage Line)</td><td colspan="3">

The Length of Low-voltage Line (km) = 0.0142 X</td></tr>
<tr><td></td><td></td><td colspan="3">The Length of Low-voltage Line (km)</td></tr>
<tr><td></td><td>25 kW</td><td colspan="3">0.36</td></tr>
<tr><td></td><td>60 kW</td><td colspan="3">0.85</td></tr>
<tr><td colspan="2">60 kW< X
(With High-voltage Line)</td><td colspan="3">

The Length of High-voltage Line (km) = 0.01 X
The Length of Low-voltage Line (km) = 0.0142 X
The Number of 3φ50 kVA Transformer (unit) = X/50</td></tr>
<tr><td rowspan="2"></td><td rowspan="2"></td><td colspan="2">The Length of Line (km)</td><td rowspan="2">The Number of 3φ50 kVA Transformer (unit)</td></tr>
<tr><td>High-voltage Line</td><td>Low-voltage Line</td></tr>
<tr><td></td><td>100 kW</td><td>1.0</td><td>1.4</td><td>2</td></tr>
<tr><td></td><td>150 kW</td><td>1.5</td><td>2.1</td><td>3</td></tr>
<tr><td></td><td>200 kW</td><td>2.0</td><td>2.8</td><td>4</td></tr>
<tr><td></td><td>1 MW</td><td>10</td><td>14</td><td>20</td></tr>
</table>

MV/LV transformer).[23] O&M cost is calculated as 2 percent of the capital cost annually and losses are handled by decrementing the net delivered electricity by 12 percent.[24]

The levelized costs of distribution for each power generation technology assessed in a mini-grid configuration are shown in Table 3.4.

Table 3.4: Power Delivery Costs Associated with Mini-grid Configurations

Generating-types	*Rated* Output	*CF* (%)	*Mini-grid* *US¢/kWh* 2005	2010	2015	*US$/kW* 2005	2010	2015
Solar-PV	25 kW	20	7.42	6.71	6.14	56	56	56
Wind	100 kW	25	3.80	3.61	3.49	193	193	193
PV-wind Hybrids	100 kW	30	5.09	4.72	4.42	193	193	193
Geothermal	200 kW	70	2.53	2.38	2.34	193	193	193
Biomass Gasifier	100 kW	80	1.58	1.51	1.48	193	193	193
Biogas	60 kW	80	1.03	0.99	0.99	56	56	56
Microhydro	100 kW	30	2.43	2.36	2.36	193	193	193
Diesel/Gasoline	100 kW	80	3.08	2.94	2.97	193	193	193
Microturbines	150 kW	80	4.69	4.54	4.54	193	193	193
Fuel Cells	200 kW	80	3.99	3.72	3.58	193	193	193

Table 3.4 suggests there is a separate and distinct "cost" associated with power delivery in mini-grids that, if added to generation costs, would be a significant component of overall cost of electricity. Because the fixed and variable cost of delivery is spread across electricity production, power generation technologies with low capacity factors have a higher net delivery cost burden per kWh. The proper application of these mini-grid delivery costs will depend on the planning context faced by the power system planner. If the mini-grid is

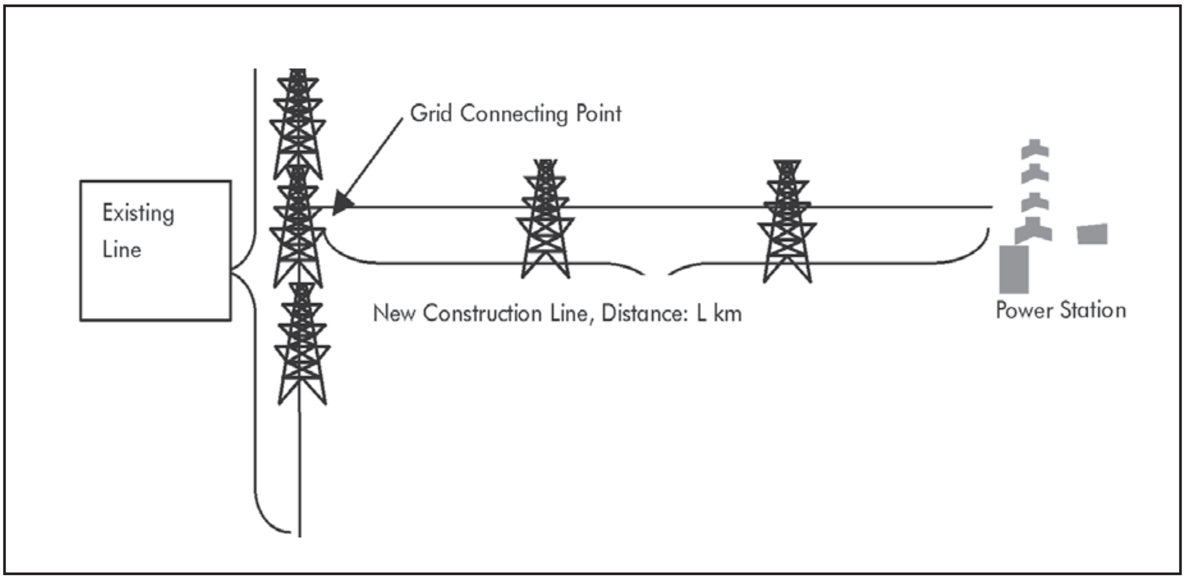
[23] *Interviews to Electric Power Companies in India, November 2004, Mahesh Vipradas, TERI in India.*
[24] *Distribution Loss Percentage = Average T&D Loss Percentage x Distribution Loss Rate=17.2% x 0.7=12%.*

being considered as an alternative to grid connection, then the system planner might want to consider these extra costs. If the mini-grid will eventually be connected to the larger grid, including the mini-grid generation sources, there might not be any reason to make such a distinction. The decision whether to include these costs in evaluating an electrification alternative is left to the practitioner. We do not include these power delivery costs in the comparisons of different generating costs by generation technology and configuration.

Transmission Costs

A large power station requires construction of transmission lines from the power station to the load. As transmission costs are driven by the distance from the power station to the load center, this is a convenient parameter for estimating transmission costs (Figure 3.2).

Figure 3.2: Calculation Model for Transmission Costs



We assume representative voltage level and line-types relative to power station rated output as shown in Table 3.5. As with the distribution cost calculation, capital and O&M costs can be expressed on a per-circuit-kilometer annualized basis by levelizing the capital cost and assuming annual O&M costs are a fixed fraction of capital costs. Transmission losses are incorporated by decrementing the net power delivery in accordance with the circuit km associated with each power generation configuration.

Table 3.5: Assigning Transmission Line Costs According to Power Station Output

Rated Output Power Station (MW)	*Representative Voltage Level (kV)*	*Line-type*	*Capital Cost per km (US$/km)*
5	69	DRAKE 1cct	28,177
10	69	DRAKE 1cct	28,177
20	69	DRAKE 1cct	28,177
30	138	DRAKE 1cct	43,687
100	138	DRAKE 2cct	78,036
150	230	DRAKE 2cct	108,205
300	230	DRAKE (2) 2cct	151,956

Source: Chubu Electric Power Company Transmission Planning Guidelines.

Using these associated transmission facilities, we can calculate the capital and levelized delivery costs associated with transmission for each grid-connected power generation technology, as shown in Table 3.6.

Table 3.6: Power Delivery Costs Associated with Transmission Facilities

Generating-types	*Rated Output (MW)*	*CF (%)*	*(US¢ x 10^{-2}) /(kWh-km)* 2005	2010	2015	*US$/(kW-km)* 2005	2010	2015
Solar-PV	5	20	4.80	4.75	4.71	5.64	5.64	5.64
Wind	10	30	1.60	1.58	1.57	2.82	2.82	2.82
Wind	100	30	0.54	0.53	0.52	0.78	0.78	0.78
Solar Thermal Without Thermal Storage	30	20	0.64	0.62	0.61	1.46	1.46	1.46
Geothermal	50	90	0.25	0.25	0.25	0.87	0.87	0.87
Biomass Gasifier	20	80	0.54	0.53	0.52	1.41	1.41	1.41
Biomass Steam	50	80	0.31	0.30	0.30	0.87	0.87	0.87
MSW/Landfill Gas	5	80	1.16	1.16	1.16	5.64	5.64	5.64
Mini-hydro	5	45	2.02	2.02	2.02	5.64	5.64	5.64
Large-hydro	100	50	0.37	0.37	0.37	0.78	0.78	0.78
Pumped Storage Hydro (peak)	150	10	1.57	1.56	1.55	0.72	0.72	0.72

(continued...)

(...Table 3.6 continued)

Generating-types	*Rated Output (MW)*	*CF (%)*	*(US¢ x 10-²) /(kWh-km) 2005*	*2010*	*2015*	*US$/(kW-km) 2005*	*2010*	*2015*
Diesel/Gasoline Generator	5	80	1.19	1.18	1.18	5.64	5.64	5.64
Diesel/Gasoline Generator (peak)	5	10	8.98	8.97	8.97	5.64	5.64	5.64
Fuel Cells	5	80	1.24	1.22	1.21	5.64	5.64	5.64
Oil/Gas Combined Turbines (peak)	150	10	1.29	1.28	1.28	0.72	0.72	0.72
Oil/Gas Combined Cycle	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Coal Steam	300	80	0.16	0.15	0.15	0.51	0.51	0.51
Coal AFB	300	80	0.15	0.15	0.15	0.51	0.51	0.51
Coal IGCC	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Oil Steam	300	80	0.19	0.19	0.18	0.51	0.51	0.51

As we saw with power delivery costs associated with mini-grids, the levelized transmission costs for power generation technologies with low rated output and low capacity factor are quite high, as the high fixed costs of transmission are spread over lower annual electricity production. The calculation approach used here yields the cost of delivering the output of a given power generation technology per circuit-km. This can be converted to a basis similar to the distribution costs by specifying the physical configuration of the transmission network. However, once again we present these results for informational purposes and do not make a blanket recommendation for how they should be used in the planning process. As with distribution-related power delivery costs, we do not include these transmission-related power delivery costs in the comparisons of different generating costs by generation technology and configuration.

Grid Integration Issues

Intermittent power sources connected to the power grid can cause frequency and voltage stability problems for the system operator. As more and more stochastic power sources such as wind turbines are being interconnected to power grids, this topic has become the subject of intensive study.[25]

[25] *Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date*, J. Charles Smith, UWIG, others.

As a general rule, all power systems must adopt counter-measures to maintain frequency and voltage stability in the event of unplanned outages of large generators, due to renewable resource variability or any other reason. The problem of wind power intermittency is exacerbated by the many induction generators in use, as the large inrush currents on cut-in have a hard-to-predict impact on voltage and frequency stability.

Mitigation measures for ensuring voltage stability are well known, and include procuring additional operating reserves, arranging for contingency resources and incorporating additional voltage control capability. Numerous studies have estimated the costs associated with accommodating wind power, as shown in Table 3.7.

Table 3.7: Costs of Accommodating Wind Power Intermittency (US¢/kWh)

Study	*Relative Wind Penetration (%)*	*Spinning Reserve*	*Load Following Operation*	*Unit Commitment*	*Total Capacity Factor*
UWIG/Xcel	3.5	0	0.041	0.144	0.185
PacifiCorp	20	0	0.25	0.3	0.550
BPA	7	0.019	0.028	0.1-0.18	0.147-0.227
Hirst	0.06-0.12	0.005-0.03	0.07-0.28	NA	NA
We Energies I	4	0.112	0.009	0.069	0.190
We Energies II	29	0.102	0.015	0.175	0.292
Great River I	4.3	–	–	–	0.319
Great River II	16.6	–	–	–	0.453
CA RPS Phase I	4	0.017	NA	NA	NA

Source: E.ON.
Note: NA = Not applicable; "–" means no cost needed.

4. Results and Discussion

This section presents the results of the economic assessment of power generation technologies in various grid configurations. The work undertaken was intended to identify, characterize and assess the technical, economic and commercial prospects for a broad spectrum of electricity generation and delivery technologies capable of serving rural, peri-urban and urban populations in developing countries. The study covered a total of 22 technologies, which, together, with applications, permutations and deployment configurations comprised 42 total cases. The technologies included both renewable and fossil fuel-based power generation technologies in configurations suitable for off-grid, mini-grid and small and large grid-connected operations.

Our objective in developing these economic assessments was to assist the power system planner or policy maker to make the right technology selection, given local conditions and available resources. The assessment results are necessarily generic, providing an indicative but not conclusive or specific comparison of relative generation capital cost and generating cost. Given the variability in RE resources and other technology performance parameters, these first-order calculations need to be refined using national or site-specific data to yield a conclusive comparison. Furthermore, the analysis does not consider the interactions and combinations of use of technologies within an overall power supply plan in order to provide electricity at the least cost by appropriate combination of peak, mid-peak and off-peak generation options.

There are several summary result Tables included in the following subsections. Section 4.1 presents the generation capital costs of 22 electric power generation technologies in US$ per kW. Section 4.2 presents the corresponding levelized generating costs in US¢ per kWh. The economic assessment process generated similarly detailed data for capital costs and generating costs projected for 2010 and 2015, including estimated uncertainty bands. This information is provided technology-by-technology in the CD-ROM (see Annex 3) to this report.

Power Generation Technology Configurations

Throughout the presentation of assessment results we retain generation capacity as a simple organizing principle. We distinguish four size ranges: Large grid-connected power generation, small grid-connected power generation, power generation in mini-grids and off-grid power generation.

Power generation technologies larger than 100 MW capacity are exclusively conventional power plants burning fossil fuels (coal, heavy oil or natural gas), or are large hydroelectric power plants. In developing countries, power plants of this magnitude are operated by central or state electricity boards or in some cases by investor-owned utility companies or by independent power operations. The units in this range are always grid-connected and serve urban or peri-urban areas with high-load density.

Power generation technologies in the 5-50 MW range can be either conventional power plants burning fossil fuels or renewable power plants using solar, wind, geothermal, hydro, biomass or biogas resources. The units in this range are usually grid-connected, but can also be operated in a mini- or distributed-grid configuration or in auto-production mode. These power generation technology types and sizes find wide application in grid-connected power applications serving rural and suburban areas, dedicated industrial or large commercial customers, and mini-grids serving rural or peri-urban areas. The option of combined heat and power plants are not considered in this evaluation.

Power generation technologies smaller than 5,000 kW are often configured for serving small stand-alone loads or noninterconnected mini-grids. These technologies frequently use RE sources including solar, wind, hydro, biomass or biogas, are often configured in hybrid arrangements with small, diesel engine-generators as a back-up supply, and are frequently found in mini-grid or off-grid applications and in developing countries.

Finally, it is possible to configure some power generation technologies down to the individual facility, household or business. This type of off-grid arrangement is possible with solar, wind, hydro, biomass and diesel power generation technologies of size less than 25 kW. However, such an arrangement would be a least-cost electrification solution only if mini-grid arrangements or grid connection were not economical prospects.

Results: Power Generation Capital Costs

Table 4.1 and Table 4.2 provide detailed economic capital cost characterizations of each power generation technology configuration as of 2005, arranged according to use of RE vs. fossil fuels. This data is useful for the planner attempting to estimate capital cost requirements for various technologies and size ranges. As would be expected, the larger conventional power stations are much less expensive in initial cost terms than the renewable power technologies, although there are some exceptions. Biomass gasifiers, wind power and micro/mini hydro all have capital costs of less than US$1,800/kW. Table 4.3 shows the range of 2005 and projected 2010 and 2015 capital costs for each generation technology.

Table 4.1: 2005 Renewable Power Technology Capital Costs (US$/kW)

Technology		Life Years	Capacity Factor %	Rated Output kW	Engineering	Equipment & Materials	Civil	Erection	Process Contingency	Total
• Solar-PV		20	20	0.050	–	6,780	–	–	700	**7,480**
		20	20	0.300	–	6,780	–	–	700	**7,480**
		25	20	25	200	4,930	980	700	700	**7,510**
		25	20	5,000	200	4,640	980	560	680	**7,060**
• Wind		20	25	0.300	50	3,390	770	660	500	**5,370**
		20	25	100	50	2,050	260	160	260	**2,780**
		20	30	10,000	40	1,090	70	100	140	**1,440**
		20	30	100,000	40	940	60	80	120	**1,240**
• PV-wind-hybrid		20	25	0.300	30	4,930	460	390	630	**6,440**
		20	30	100	130	3,680	640	450	520	**5,420**
• Solar Thermal With Storage		30	50	30,000	920	1,920	400	1,150	460	**4,850**
Without Storage		30	20	30,000	550	890	200	600	240	**2,480**
• Geothermal	Binary	20	70	200	450	4,350	750	1,670	–	**7,220**
	Binary	30	90	20,000	310	1,560	200	2,030	–	**4,100**
	Flash	30	90	50,000	180	955	125	1,250	–	**2,510**
• Biomass Gasifier		20	80	100	70	2,490	120	70	130	**2,880**
		20	80	20,000	40	1,740	100	50	100	**2,030**
• Biomass Steam		20	80	50,000	90	1,290	170	70	80	**1,700**
• MSW/Landfill Gas		20	80	5,000	90	1,500	900	600	160	**3,250**
• Biogas		20	80	60	70	1,180	690	430	120	**2,490**
• Pico/Micro Hydro		5	30	0.300	–	1,560	–	–	–	**1,560**
		15	30	1	–	1,970	570	140	–	**2,680**
		30	30	100	190	1,400	810	200	–	**2,600**
• Mini-hydro		30	45	5,000	200	990	1,010	170	–	**2,370**
• Large-hydro		40	50	100,000	200	560	1,180	200	–	**2,140**
• Pumped Storage		40	10	150,000	300	810	1,760	300	–	**3,170**

Note: "–" means no cost needed.

Table 4.2: 2005 Conventional and Emerging Power Technology Capital Costs (US$/kW)

Technology	Life Years	Capacity Factor %	Rated Output kW	Engineering	Equipment & Materials	Civil	Erection	Process Contingency	**Total**
• Diesel/Gasoline Generator	10	30	0.300	–	890	–	–	–	**890**
	10	30	1	–	680	–	–	–	**680**
	20	80	100	10	600	10	20	–	**640**
Base Load	20	80	5,000	30	510	30	30	–	**600**
Peak Load	20	10	5,000	30	510	30	30	–	**600**
• Microturbines	20	80	150	10	830	10	20	90	**960**
• Fuel Cell	20	80	200	–	3,100	–	20	520	**3,640**
	20	80	5,000	–	3,095	5	10	520	**3,630**
• Oil/Gas Combustion Turbines	25	10	150,000	30	370	45	45	–	**490**
• Oil/Gas Combined Cycle	25	80	300,000	50	480	50	70	–	**650**
• Coal Steam SubCritical	30	80	300,000	100	870	110	110	–	**1,190**
(with FGD SubCritical	30	80	500,000	90	850	100	100	–	**1,140**
& SCR) SC	30	80	500,000	100	880	100	100	–	**1,180**
USC	30	80	500,000	110	850	100	100	100	**1,260**
• Coal IGCC	30	80	300,000	150	1,010	150	100	200	**1,610**
(without FGD & SCR)	30	80	500,000	140	940	140	100	180	**1,500**
• Coal AFBC	30	80	300,000	110	730	120	120	100	**1,180**
(without FGD & SCR)	30	80	500,000	110	680	120	110	100	**1,120**
• Oil Steam	30	80	300,000	80	600	100	100	–	**880**

Source: E.ON.
Note: "–" means no cost needed.

Table 4.3: Power Generation Technology Capital Costs Now and in Future (2005, 2010, 2015)

Generating-type	Capacity	2005			2010			2015		
		Min	**Probable**	Max	Min	**Probable**	Max	Min	**Probable**	Max
Solar-PV	50 W	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	300 W	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	25 kW	6,710	**7,510**	8,320	5,630	**6,590**	7,380	4,800	**5,860**	6,640
	5 MW	6,310	**7,060**	7,810	5,280	**6,190**	6,930	4,500	**5,500**	6,235
Wind	300 W	4,820	**5,370**	5,930	4,160	**4,850**	5,430	3,700	**4,450**	5,050

(continued...)

(...Table 4.3 continued)

Generating Type	Capacity	2005 Min	2005 Probable	2005 Max	2010 Min	2010 Probable	2010 Max	2015 Min	2015 Probable	2015 Max
	100 kW	2,460	**2,780**	3,100	2,090	**2,500**	2,850	1,830	**2,300**	2,670
	10 MW	1,270	**1,440**	1,610	1,040	**1,260**	1,440	870	**1,120**	1,300
	100 MW	1,090	**1,240**	1,390	890	**1,080**	1,230	750	**960**	1,110
PV-wind Hybrids	300 W	5,670	**6,440**	7,210	4,650	**5,630**	6,440	3,880	**5,000**	5,800
	100 kW	4,830	**5,420**	6,020	4,030	**4,750**	5,340	3,420	**4,220**	4,800
Solar Thermal (without thermal storage)	30 MW	2,290	**2,480**	2,680	1,990	**2,200**	2,380	1,770	**1,960**	2,120
Solar Thermal (with thermal storage)	30 MW	4,450	**4,850**	5,240	3,880	**4,300**	4,660	3,430	**3,820**	4,140
Geothermal	200 kW (binary)	6,480	**7,220**	7,950	5,760	**6,580**	7,360	5,450	**6,410**	7,300
	20 MW (binary)	3,690	**4,100**	4,500	3,400	**3,830**	4,240	3,270	**3,730**	4,170
	50 MW (flash)	2,260	**2,510**	2,750	2,090	**2,350**	2,600	2,010	**2,290**	2,560
Biomass Gasifier	100 kW	2,490	**2,880**	3,260	2,090	**2,560**	2,980	1,870	**2,430**	2,900
	20 MW	1,760	**2,030**	2,300	1,480	**1,810**	2,100	1,320	**1,710**	2,040
Biomass Steam	50 MW	1,500	**1,700**	1,910	1,310	**1,550**	1,770	1,240	**1,520**	1,780
MSW/Landfill Gas	5 MW	2,960	**3,250**	3,540	2,660	**2,980**	3,270	2,480	**2,830**	3,130
Biogas	60 kW	2,260	**2,490**	2,720	2,080	**2,330**	2,570	2,000	**2,280**	2,540
Pico/Micro Hydro	300W	1,320	**1,560**	1,800	1,190	**1,485**	1,770	1,110	**1,470**	1,810
	1 kW	2,360	**2,680**	3,000	2,190	**2,575**	2,950	2,090	**2,550**	2,990
	100 kW	2,350	**2,600**	2,860	2,180	**2,470**	2,750	2,110	**2,450**	2,780
Mini-hydro	5 MW	2,140	**2,370**	2,600	2,030	**2,280**	2,520	1,970	**2,250**	2,520
Large-hydro	100 MW	1,930	**2,140**	2,350	1,860	**2,080**	2,290	1,830	**2,060**	2,280
Pumped Storage Hydro	150 MW	2,860	**3,170**	3,480	2,760	**3,080**	3,400	2,710	**3,050**	3,380
Diesel/Gasoline Generator	300 W	750	**890**	1,030	650	**810**	970	600	**800**	980
	1k W	570	**680**	790	500	**625**	750	470	**620**	770
	100 kW	550	**640**	730	480	**595**	700	460	**590**	720
	5 MW (baseload)	520	**600**	680	460	**555**	650	440	**550**	660
	5 MW (peak load)	520	**600**	680	460	**555**	650	440	**550**	660
Micro Turbines	150 kW	830	**960**	1,090	620	**780**	910	500	**680**	810
Fuel Cells	200 kW	3,150	**3,640**	4,120	2,190	**2,820**	3,260	1,470	**2,100**	2,450
	5 MW	3,150	**3,630**	4,110	2,180	**2,820**	3,260	1,470	**2,100**	2,450

(continued...)

(...Table 4.3 continued)

Generating Type	*Capacity*	2005			2010			2015		
		Min	***Probable***	*Max*	*Min*	***Probable***	*Max*	*Min*	***Probable***	*Max*
Oil/Gas Combined Turbines	150 MW (1,100C class)	430	**490**	550	360	**430**	490	340	**420**	490
Oil/Gas Combined Cycle	300 MW (1,300C class)	570	**650**	720	490	**580**	660	450	**560**	650
Coal Steam with FGD and SCR (Subcritical)	300 MW	1,080	**1,190**	1,310	960	**1,080**	1,220	910	**1,060**	1,200
Coal Steam with FGD and SCR (Subcritical)	500 MW	1,030	**1,140**	1,250	910	**1,030**	1,150	870	**1,010**	1,140
Coal Steam with FGD and SCR (SC)	500 MW	1,070	**1,180**	1,290	950	**1,070**	1,200	900	**1,050**	1,190
Coal Steam with FGD and SCR (USC)	500 MW	1,150	**1,260**	1,370	1,020	**1,140**	1,250	960	**1,100**	1,230
Coal AFB without FGD and SCR	300 MW	1,060	**1,180**	1,300	940	**1,070**	1,210	880	**1,040**	1,180
	500 MW	1,010	**1,120**	1,230	900	**1,020**	1,140	840	**990**	1,120
Coal IGCC without FGD and SCR	300 MW	1,450	**1,610**	1,770	1,200	**1,390**	1,550	1,070	**1,280**	1,440
	500 MW	1,350	**1,500**	1,650	1,130	**1,300**	1,450	1,000	**1,190**	1,340
Oil Steam	300 MW	780	**880**	980	700	**810**	920	670	**800**	920

Results: Levelized Power Generating Costs

A useful expression for comparing different power supply costs is the levelized power generating costs expressed on a per-kWh basis. Table 4.4 and Table 4.5 provide levelized generation costs for 2005 for renewable power generation technologies and conventional and emerging power technologies, respectively. The components of generation operating costs (levelized capital costs, O&M costs and fuel costs) are provided for all 42 power generation technology configurations assessed. Table 4.6 provides the average and estimated uncertainty band results for generation costs in 2005, 2010 and 2015.

In large grid-connected configurations, most of the conventional, renewable and emerging power generation technologies are comparably priced at around US¢4-6/kWh. Geothermal, coal-fired steam electric and coal AFBC are the most competitive at present, with wind and coal IGCC expected to join this mix by 2015. Site-specific considerations such as load profile, demand growth and especially the cost differential between oil, natural gas and coal prices, determine which specific technology is the least expensive and most attractive. Both oil-fired steam electric and gas combined cycle are expected to become more costly instead of less over the next 10 years.

As regards small grid-connected power generation configurations (less than 50 MW), there is a much greater generating cost spread among power technologies, with most renewable technologies being more economical than the conventional diesel generator alternative.

Table 4.4: 2005 Renewable Power Technology Generating Costs (US¢/kWh)

Technology		Rated Output kW	Levelized Capital Cost	Fixed O&M Costs	Variable O&M Costs	Fuel Costs	Average Levelized Cost
• Solar-PV		0.050	45.59	3.00	13.00	–	61.59
		0.300	45.59	2.50	8.00	–	56.09
		25	42.93	1.50	7.00	–	51.43
		5,000	40.36	0.97	0.24	–	41.57
• Wind		0.300	26.18	3.49	4.90	–	34.57
		100	13.55	2.08	4.08	–	19.71
		10,000	5.85	0.66	0.26	–	6.71
		100,000	5.08	0.53	0.22	–	5.79
• PV-wind-hybrid		0.300	31.40	3.48	6.90	–	41.78
		100	22.02	2.07	6.40	–	30.49
• Solar-thermal	With Storage	30,000	10.68	1.82	0.45	–	12.95
	Without Storage	30,000	13.65	3.01	0.75	–	17.41
• Geothermal	Binary	200	12.57	2.00	1.00	–	15.57
	Binary	20,000	5.02	1.30	0.40	–	6.72
	Flash	50,000	3.07	0.90	0.30	–	4.27
• Biomass Gasifier		100	4.39	0.34	1.57	2.66	8.96
		20,000	3.09	0.25	1.18	2.50	7.02
• Biomass Steam		50,000	2.59	0.45	0.41	2.50	5.95
• MSW/Landfill Gas		5,000	4.95	0.11	0.43	1.00	6.49
• Biogas		60	3.79	0.34	1.54	1.10	6.77
• Pico/Micro-hydro		0.300	14.24	0.00	0.90	–	15.14
		1	12.19	0.00	0.54	–	12.73
		100	9.54	1.05	0.42	–	11.01
• Mini-hydro		5,000	5.86	0.74	0.35	–	6.95
• Large-hydro		100,000	4.56	0.50	0.32	–	5.38
• Pumped Storage		150,000	34.08	0.32	0.33	–	34.73

Note: "–" means no cost needed.

Table 4.5: 2005 Conventional/Emerging Power Technology Generating Costs (US¢/kWh)

Technology		Rated Output kW	Levelized Capital Cost	Fixed O&M Costs	Variable O&M Costs	Fuel Costs	Total
• Diesel/Gasoline Generator		0.300	5.01	–	5.00	54.62	**64.63**
		1	3.83	–	3.00	44.38	**51.21**
		100	0.98	2.00	3.00	14.04	**20.02**
	Baseload	5,000	0.91	1.00	2.50	4.84	**9.25**
	Peak Load	5,000	7.31	3.00	2.50	4.84	**17.65**
• Microturbines		150	1.46	1.00	2.50	26.86	**31.82**
• Fuel Cell		200	5.60	0.10	4.50	16.28	**26.48**
		5,000	5.59	0.10	4.50	4.18	**14.36**
• Combustion Turbines	Natural Gas	150,000	5.66	0.30	1.00	6.12	**13.08**
	Oil		5.66	0.30	1.00	15.81	**22.77**
• Combined Cycle	Natural Gas	300,000	0.95	0.10	0.40	4.12	**5.57**
	Oil		0.95	0.10	0.40	10.65	**12.10**
• Coal Steam (with FGD & SCR)	SubCritical	300,000	1.76	0.38	0.36	1.97	**4.47**
	SubCritical	500,000	1.67	0.38	0.36	1.92	**4.33**
	SC	500,000	1.73	0.38	0.36	1.83	**4.29**
	USC	500,000	1.84	0.38	0.36	1.70	**4.29**
• Coal IGCC (without FGD & SCR)		300,000	2.49	0.90	0.21	1.79	**5.39**
		500,000	2.29	0.90	0.21	1.73	**5.14**
• Coal AFBC (without FGD & SCR)		300,000	1.75	0.50	0.34	1.52	**4.11**
		500,000	1.64	0.50	0.34	1.49	**3.97**
• Oil Steam		300,000	1.27	0.35	0.30	5.32	**7.24**

Note: "–" means no cost needed.

Geothermal and wind both have excellent prospects, local resource availability allowing, with costs estimated at US¢4-6/kWh. Several biomass technologies (biomass gasifier, biomass steam and waste-to-power via Anaerobic Digestion) all are estimated to cost around US¢5-7/kWh both now and in future.

Mini-grid applications are village- and district-level networks with loads between 5 kW and 500 kW not connected to a national grid. The assessment indicates that numerous RE technologies (biomass, biogas, geothermal, wind and micro-hydro) costing

US¢6-15/kWh are the potential least-cost generation option for mini-grids, assuming a sufficient RE resource is available. Two biomass technologies – biogas digesters and biomass gasifiers – seem particularly promising, due to their high capacity factors and availability in size ranges matched to mini-grid loads. Geothermal also appears economical, recognizing that it is restricted to a relatively few developing economies. Since so many RE sources are viable in this size range, mini-grid planners should thoroughly review their options to make the best selection.

The only electrification technology choice for small, isolated loads is expensive diesel generation and several renewable power options, including pico-hydo, geothermal, small wind and solar PV. These renewable technologies are the least-cost option on a levelized generating cost basis for off-grid electrification, assuming resource availability. However, these off-grid configurations are very expensive (US¢30-50/kWh), with pico-hydro the notable exception at only US¢12/kWh. However, they are economical when compared with the US¢45-60/kWh for a small, stand-alone gasoline or diesel engine generator.

Discussion: Power Delivery Costs

The costs of transmitting and distributing electricity production need to be included in the overall economic assessment of different power generation configurations. As described in Section 3, the capital costs of transmission and delivery are driven by the amount of power transmitted and the distance over which delivery takes place. For large grid-connected power plants, comparably located with respect to the load being served the associated transmission and distribution costs cancel out and a comparison can be made based on generation costs alone. However, for some smaller loads with low capacity factors, especially in a mini-grid configuration, the power delivery costs on a levelized basis can vary considerably when spread across the amount of electricity delivered. These costs need to be taken into account in a way that does not unduly tilt the economic assessment according to capacity factor. Because the economic assessment of power delivery requirements needs more development, we do not include the capital cost or levelized cost of power delivery in our comparisons of power generation technology alternatives.

Discussion: Sensitivity of Projected Generation Costs to Technology Change and Fuel Costs

As described in the Executive Summary, many renewable power generation technologies are expected to have improved performance and lower capital costs in the near future. Some conventional power generation technologies, especially coal- and oil-fired steam electric, also have prospects for improved performance and lower costs through use of advanced materials allowing higher temperature operation. Additionally, several emerging technologies, including microturbines and fuel cells as well as coal-fired IGCC and AFBC, are expected to be very competitive within a few years. We have done our best to anticipate the performance improvements and capital cost reductions of these technologies based on industry literature and forecasts.

An additional key factor in projecting future costs is the cost of fuel. Any fossil fuel using power generation technology and especially oil- and gas-fired technologies are subject to secular fuel price increases, fuel price fluctuations and growing risk of availability. Gas and oil price forecasts have uniformly taken on a broader error band just in the past year.

These factors – performance improvements outlook, cost reduction trajectories and uncertainties in cost input assumptions – were captured in projections of capital and production costs for each power generation technology in 2010 and 2015. An uncertainty analysis allowed future capital and generation cost projections to include an "uncertainty band" around the average cost estimate for each technology and configuration.

An argument can be made that conservative power system planners would be better off choosing power generation technologies that have a narrower sensitivity range in future capital and generating costs forecasts. Generation technologies that are not dependent on fossil fuels and are fairly well developed at present will tend to have the narrowest sensitivities in forecast capital or generating cost. This category includes several of the RETs, notably the biomass, hydroelectric and geothermal technologies across size ranges. Such insensitivity to technology or fuel price variability could be a competitive advantage for these technologies.

Conclusion

RETs fare surprisingly well in several electrification configurations. In addition to proving more economical in the very expensive off-grid category, they are also more economical in mini-grid applications and even when compared with small grid-connected generation (less than 50 MW). Since power system planners generally operate on an incremental basis, with new capacity additions (generation, transmission or distribution) timed and sized to accommodate the location and pace of load growth, the findings here suggest that scale and insensitivity to fuel and technology change factors could affect the economics of choosing generation configurations in future. When the national or regional grid is developed and includes sufficient transmission capacity, and incremental load growth is fast, large, central-station gas combined cycle and coal fired power plants would clearly be the least-cost alternatives. However, if the size of the grid is limited, or the incremental load growth is small, it may make economic sense to add several smaller renewable or diesel power stations rather than add one very large conventional power station. Taking advantage of local resources such as indigenous coal, gas, biomass or geothermal or wind or hydro and constructing smaller power stations may provide energy security and avoid some of the uncertainty associated with international fuel prices.

Table 4.6: Levelized Generating Cost with Uncertainty Analysis

Generating-types	*Capacity*	*2005*			*2010*			*2015*		
		Mini	**Probable**	Max	Mini	**Probable**	Max	Mini	**Probable**	Max
Solar-PV	50 W	51.8	**61.6**	75.1	44.9	**55.6**	67.7	39.4	**51.2**	62.8
	300 W	46.4	**56.1**	69.5	39.6	**50.1**	62.1	34.2	**45.7**	57.0
	25 kW	43.1	**51.4**	63.0	37.7	**46.2**	56.6	33.6	**42.0**	51.3
	5 MW	33.7	**41.6**	52.6	28.9	**36.6**	46.3	25.0	**32.7**	41.4
Wind	300 W	30.1	**34.6**	40.4	27.3	**32.0**	37.3	25.2	**30.1**	35.1
	100 kW	17.2	**19.7**	22.9	15.6	**18.3**	21.3	14.4	**17.4**	20.2
	10 MW	5.8	**6.8**	8.0	5.0	**6.0**	7.1	4.3	**5.5**	6.5
	100 MW	5.0	**5.8**	6.8	4.2	**5.1**	6.1	3.7	**4.7**	5.5
PV-wind-hybrids	300 W	36.1	**41.8**	48.9	31.6	**37.8**	44.5	28.1	**34.8**	40.9
	100 kW	26.8	**30.5**	34.8	23.8	**27.8**	31.7	21.4	**25.6**	29.1
Solar-thermal (without thermal storage)	30 MW	14.9	**17.4**	21.0	13.5	**15.9**	19.0	12.4	**14.5**	17.3
Solar-thermal (with thermal storage)	30 MW	11.7	**12.9**	14.3	10.5	**11.7**	12.9	9.6	**10.7**	11.7
Geothermal	200 kW (binary)	14.2	**15.6**	16.9	13.0	**14.5**	15.9	12.5	**14.2**	15.7
	20 MW (binary)	6.2	**6.7**	7.3	5.8	**6.4**	6.9	5.7	**6.3**	6.8
	50 MW (flash)	3.9	**4.3**	4.6	3.7	**4.1**	4.4	3.6	**4.0**	4.4
Biomass Gasifier	100 kW	8.2	**9.0**	9.7	7.6	**8.5**	9.4	7.3	**8.3**	9.5
	20 MW	6.4	**7.0**	7.6	6.0	**6.7**	7.5	5.8	**6.5**	7.5
Biomass Steam	50 MW	5.4	**6.0**	6.5	5.2	**5.7**	6.4	5.1	**5.7**	6.6
MSW/Landfill Gas	5 MW	6.0	**6.5**	7.0	5.6	**6.1**	6.6	5.3	**5.9**	6.4
Biogas	60 kW	6.3	**6.8**	7.2	6.0	**6.5**	7.1	5.9	**6.5**	7.1
Pico/Micro Hydro	300 W	12.4	**15.1**	18.4	11.4	**14.5**	18.0	10.8	**14.3**	18.2
	1 kW	10.7	**12.7**	15.2	10.1	**12.3**	14.8	9.7	**12.1**	14.9

(continued...)

(...Table 4.6 continued)

Generating-types	*Capacity*		*2005*			*2010*			*2015*	
	100 kW	9.6	**11.0**	12.8	9.1	**10.5**	12.3	8.9	**10.5**	12.3
Mini Hydro	5 MW	5.9	**6.9**	8.3	5.7	**6.7**	8.1	5.6	**6.6**	8.0
Large Hydro	100 MW	4.6	**5.4**	6.3	4.5	**5.2**	6.2	4.5	**5.2**	6.2
Pumped Storage Hydro	150 MW	31.4	**34.7**	38.1	30.3	**33.8**	37.2	29.9	**33.4**	36.9
Diesel/Gasoline Generator	300 W	59.0	**64.6**	72.5	52.4	**59.7**	71.8	52.5	**60.2**	75.0
	1 kW	46.7	**51.2**	57.6	41.4	**47.3**	57.1	41.5	**47.7**	59.7
	100 kW	18.1	**20.0**	23.1	16.6	**19.0**	23.3	16.7	**19.2**	24.3
	5 MW (base load)	8.3	**9.3**	10.8	7.6	**8.7**	10.8	7.6	**8.8**	11.3
	5 MW (peak load)	16.2	**17.7**	19.6	15.0	**16.7**	19.1	14.9	**16.7**	19.6
Microturbines	150 kW	30.4	**31.8**	33.9	28.8	**30.7**	33.5	28.5	**30.7**	34.2
Fuel Cells	200 kW	25.2	**26.5**	28.2	22.8	**24.7**	26.6	21.5	**23.7**	25.8
	5 MW	13.2	**14.4**	15.8	11.0	**12.7**	14.4	9.6	**11.7**	13.4
Oil/Gas Combustion Turbines	150 MW (1,100C class)	11.9	**13.1**	14.7	10.4	**11.8**	14.0	10.2	**11.8**	14.5
Oil/Gas Combined Cycle	300 MW (1,300C class)	4.94	**5.57**	6.55	4.26	**5.10**	6.47	4.21	**5.14**	6.85
Coal Steam with FGD & SCR (SubCritical)	300 MW	4.18	**4.47**	4.95	3.91	**4.20**	4.76	3.86	**4.20**	4.84
Coal Steam with FGD & SCR (SubCritical)	500 MW	4.05	**4.33**	4.79	3.77	**4.07**	4.62	3.74	**4.06**	4.69
Coal Steam with FGD & SCR (SubCritical)	500 MW	4.02	**4.29**	4.74	3.74	**4.04**	4.56	3.72	**4.03**	4.63
Coal Steam with FGD & SCR (UltraSuperCritical)	500 MW	4.02	**4.29**	4.71	3.74	**4.02**	4.51	3.69	**3.99**	4.55
Coal AFB without FGD & SCR	300 MW	3.88	**4.11**	4.56	3.72	**3.98**	4.55	3.67	**3.96**	4.55
	500 MW	3.75	**3.97**	4.40	3.61	**3.86**	4.42	3.58	**3.83**	4.71
Coal IGCC without FGD & SCR	300 MW	5.05	**5.39**	5.90	4.58	**4.95**	5.52	4.40	**4.81**	5.43
	500 MW	4.81	**5.14**	5.62	4.38	**4.74**	5.28	4.21	**4.60**	5.19
Oil Steam	300 MW	6.21	**7.24**	9.00	5.50	**6.70**	9.08	5.49	**6.78**	9.63

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Annex 1

Detailed Technology Descriptions and Cost Assumptions

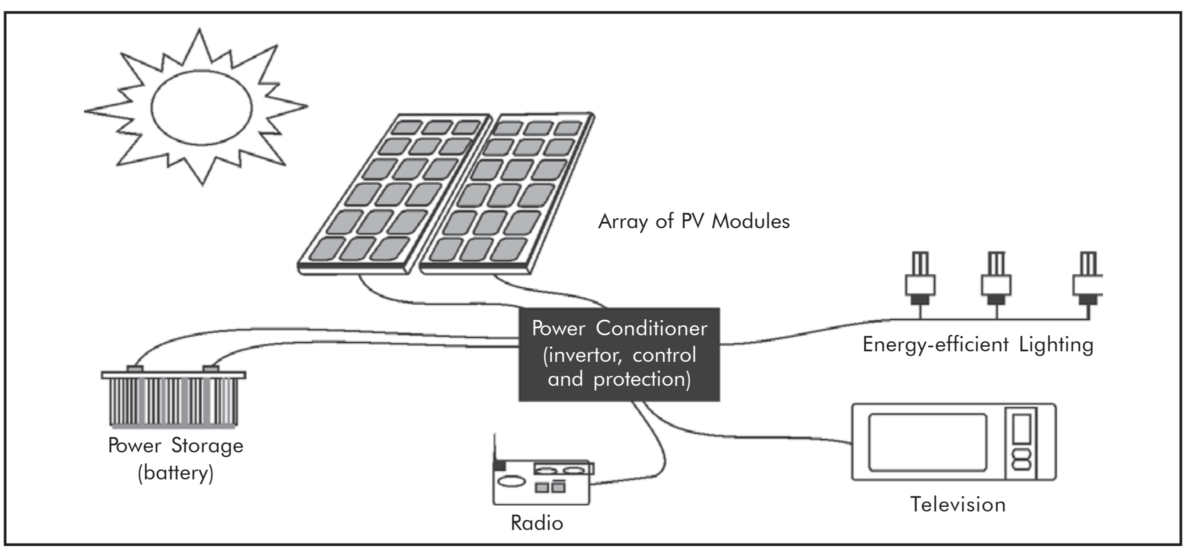
Solar Photovoltaic Technologies

SPV systems utilize semiconductor-based materials which directly convert solar energy into electricity. These semiconductors, called solar cells, produce an electrical charge when exposed to sunlight. Solar cells are assembled together to produce solar modules. A group of solar modules connected together to produce the desired power is called a solar array.

The first SPV cell was developed in 1950. Very expensive at first, early applications of photovoltaic power systems were mainly for space programs. Terrestrial applications of SPV started the in late 70s and were primarily for powering small, portable gadgets like calculators and watches. By the 80s, a number of large-scale but still niche markets for SPV systems had emerged, mostly for remote power needs such as lighting, telecommunications and pumping. In spite of its high cost, SPV systems have steadily gained power generation market share due to their ability to produce electricity with no moving parts, no fuel requirements, zero emissions, no noise and no need for grid connection. The modular nature of SPV, which allows systems to be configured to produce power from W (s) to MW (s), gives it a unique advantage over other technologies.

An SPV system typically consists of an array of solar cells, power conditioning and/or controlling device such as inverter or regulator, an electricity storage device such as battery (except in grid applications), and support structure and cabling connecting the power system to either the load or the grid. A typical SPV system arrangement is shown in Figure A1.1.

Figure A1.1: Typical SPV System Arrangement



Source: DOE/EPRI.

Technology Description and Power Applications

SPV systems can be classified according to three principal applications:

- Stand-alone solar devices purpose-built for a particular end use, such as solar HF radios, solar home lighting systems, or solar coolers. These dedicated SPV systems can either be configured to include some energy storage capacity or directly power electrical or mechanical loads, such as pumping or refrigeration;
- Stand-alone solar power plants, basically small power plants designed to provide electricity from a centralized SPV power plant to a small locality like village or a building; and
- Grid-connected SPV power plants, which are equivalent to any other generator supplying power to the electricity grid.

The SPV module is the most important component of a PV system comprising 40-50 percent of the total system cost. As such, research and development programs have focused both on cost reduction and efficiency improvement of the solar modules. SPV cell technologies can be classified according to the materials and technology used in their manufacture. The major categories of commercial interest are:

- Silicon-based SPV cells, which are the most common solar cells in commercial use. Included in this family of solar cells are crystalline silicon solar cells (both single crystalline and poly-crystalline), which account for more than 90 percent of the world's solar cell production. A well-made crystalline silicon solar cell has a theoretical PV conversion efficiency of up to 20 percent;
- Amorphous silicon cells, also called thin film solar cells, which are cheaper to produce and require fewer materials as compared to the crystalline silicon cells. However, these cells have lower efficiency – typically 5-10 percent, and tend to lose up to one-third of their efficiency levels in the first year of use. Because they can be produced as thin film of semiconductor material on a glass or plastic substrate they offer a wide variety of designs and configurations, and have found application in integrated roofing/SPV arrays; and
- Compound semiconductors, which are thin film multi junction cells manufactured using other photosensitive composite solid state materials such as Cadmium/Telluride (Cd/Te) and Copper Indium Gallium Diselenide (CIGD). This is an emerging but promising technology with high efficiency levels and light weight.

Table A1.1 summarizes the characteristics of the major solar cell categories.

Table A1.1: Characteristics of Solar Cells

Technology	*Market Share*	*Efficiency Range*	*Cost Range*	*Life*	*Remarks*
Silicon Single Crystal Cells	>90%	12-20%	3- 4 US$/$W_p$	>20 years	Mature Technology
Silicon Multi Crystal Cells	6-7%	9-12%	3-4 US$/$W_p$	> 15 years	Mature Technology
Amorphous Silicon Cell Technology	3-5%	5-10%	4-5 US$/$W_p$	>10 years	Degradation of Efficiency in First Few Months.
Compound Semiconductors CIGSC	<1%	7.5% (13.5% at laboratory level) NA (maximum 16% at laboratory level,) *(1)*	NA		Commercially Available
d/Te	<1%				

Source: Renewable Energy Information Network.
Note: NA= Not applicable.

Technical, Environmental and Economic Assessment

For the SPV assessment we have chosen several common configurations of solar systems used in India (Table A1.2).

Table A1.2: SPV System Configurations and Design Assumptions

Description	*SPV Systems*		*SPV Mini-grid Power Plants*	*Large Grid-connected SPV Power Plant*
Module Capacity	50 W_p	300 W_p	25 kW	5 MW
Life Span Modules	20 Years	20 Years	25 Years	25 Years
Life Span Batteries	5 Years	5 Years	5 Years	NA
Capacity Factor	20%	20%	20%	20%

Note: NA = Not applicable.

Our analysis assumes a capacity factor of 20 percent, based on 4.8 hrs/day average power generation at peak level. Solar modules are rated at design operating conditions of 25^0C ambient temperature and solar insolation of 1,000 W/m^2. In practice and under typical weather conditions, an average solar module on an annual basis will generate peak power for about four-five hours a day, equivalent to a 20 percent capacity factor. This assumes that solar modules are deployed to face south (in Northern latitudes) and are inclined at an angle equal to latitude to achieve maximum solar energy collection throughout the year.

The environmental impact of SPV technology is nil at the point of use. Modules produce electricity silently and do not emit any harmful gases during operation. Silicon, the basic PV material used for most common solar cells, is environmentally benign. However, disposal of used batteries in environmentally safe way is important.

Table A1.3 gives the capital costs for different sized SPV systems.

Table A1.3: SPV 2005 Capital Costs (US$/kW)

Solar-PV System Capacity	*50 W*	*300 W*	*25 kW*	*5 MW*
Equipment	6,780	6,780	4,930	4,640
Civil	0	0	980	980
Engineering	0	0	200	200
Erection	0	0	700	560
Process Contingency	700	700	700	680
Total	**7,480**	**7,480**	**7,510**	**7,060**

Based on the assumed capacity factor and the life of the SPV plant, the capital cost was annualized and the total generation cost was estimated using the formulations provided in Section 2. The generation costs for the year 2004 are given in Table A1.4. Variable O&M costs include cost of battery replacement after five years for small systems (up to 25 kW) plus replacement of electronics components for larger (25 kW and 5 MW) systems.

Table A1.4: SPV 2005 System Generating Costs (US¢/kWh)

SPV System Capacity	*50 W*	*300 W*	*25 kW*	*5 MW*
Levelized Capital Cost	45.59	45.59	42.93	40.36
Fixed O&M Cost	3.00	2.50	1.50	0.97
Variable O&M Cost	12.00	8.00	7.00	0.24
Fuel Cost	0.00	0.00	0.00	0.00
Total	**61.59**	**56.09**	**51.43**	**41.57**

Future SPV Costs

SPV module costs are currently about 50 to 60 percent of the total system costs. We note that the cost of SPV modules on a per-W_p basis has fallen from US$100 in 1970 to US$5 in 1998.[26] SPV module costs continue to fall, and this drop in SPV module costs are influenced by technology advancement and growing production volume.[27]

Future costs will be driven by market growth and technology advancements, both of which can be forecast. Japan, one of the major markets for SPV and a major manufacturer of SPV modules, is forecasting production cost reductions from ¥100/W_p today to ¥75/W_p by 2010 and ¥50/W_p by 2030. The SPV industry in Europe and the United States is targeting costs of US$1.5-2.00/$W_p$ within 10 years, based on technological improvements as well as a growth in production volumes of 20-30 percent (Table A1.5).

Europe and the United States is targeting costs of US$1.5-2.00/$W_p$ within 10 years, based on technological improvements as well as a growth in production volumes of 20-30 percent (Table A1.5).

Table A1.5: Projected SPV Module Costs

Cost	*Europe*	*United States*	*Japan*	*India*
SPV Module Costs 2004	€5.71/W_p	US$5.12/$W_p$	¥100/Wp	Rs 150/W_p
Target Cost in 2010	€1.5-2/W_p	US$1.5-2/$W_p$	¥75/W_p	Rs 126/W_p*(@US$2.75/$W_p$)
Expected Cost	€0.5/W_p	NA	¥50/W_p (Note-2030 projection)	Rs 92/W_p* in 2015 (@US$ 2/W_p)

Sources: http://www.solarbuzz.com/ModulePrices.htm; http://www.solarbuzz.com/ModulePrices.htm NEDO (Japan); TERI (India).
Note: NA = Not applicable.

We have based SPV capital cost projections for the year 2010 and 2015 on the forecasts shown in Table A1.5. Our projection assumes that, as in the past, balance of system (BOS) costs will come down due to improvements in the technology of electronics components and batteries, as well as increase in production volume. Thus, we assume that BOS costs

[26] The challenges of cold climates PV in Canada's North, Renewable Energy World, July 1998, pp 36-39.
[27] SPV sales have increased from 200 MW in 1999 to 427 MW in 2002 and to above 900 MW in 2004.

will follow the same international trends as module costs. Installation and O&M costs are not likely to change significantly, they are assumed to be constant when calculating future system capital, installation and operational costs. The results of our projection, including uncertainty bands, are provided in Table A1.6.

Table A1.6: SPV System Capital Costs Projections (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
50 W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
300 W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
25 kW	6,710	7,510	8,320	5,630	6,590	7,380	4,800	5,860	6,640
5 MW	6,310	7,060	7,810	5,280	6,190	6,930	4,500	5,500	6,230

Uncertainty Analysis

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs and capacity factor. Most variables were allowed to vary over a ±20 percent range. Projected SPV generation costs for the years 2010 and 2015 resulting from the uncertainty analysis are shown in Table A1.7. The dependence of the generation cost on uncertainty of different parameters is shown with tornado charts given in Annex 4.

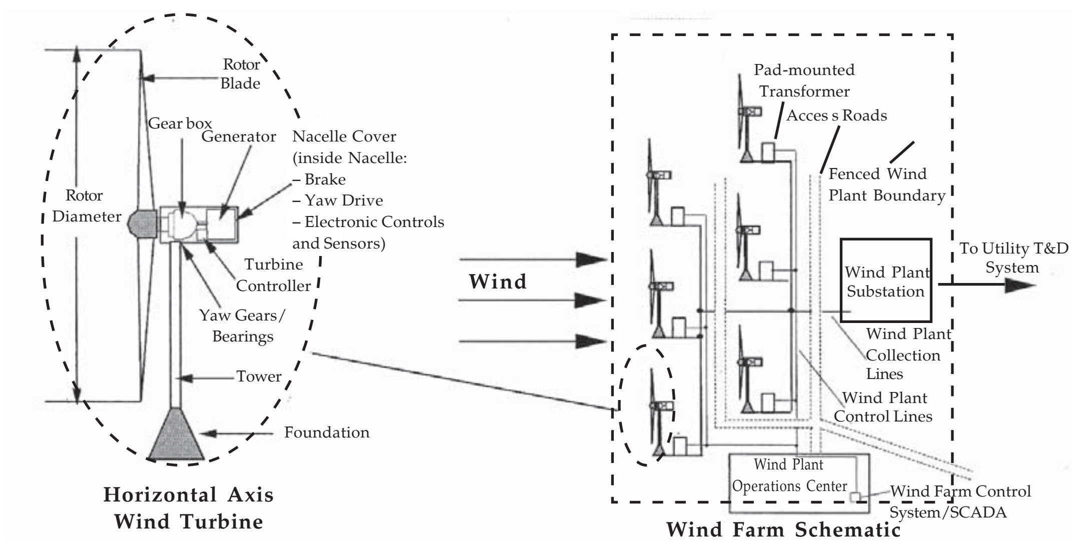
Table A1.7: Uncertainty Analysis of SPV Generation Costs (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
50 W	51.8	61.6	75.1	44.9	55.6	67.7	39.4	51.2	62.8
300 W	46.4	56.1	69.5	39.6	50.1	62.1	34.2	45.7	57.0
25 kW	43.1	51.4	63.0	37.7	46.2	56.6	33.6	42.0	51.3
5 MW	33.7	41.6	52.6	28.9	36.6	46.3	25.0	32.7	41.4

Annex 2
Wind Electric Power Systems

A wind power generator converts the kinetic energy of the wind into electric power through rotor blades connected to a generator. Horizontal axis wind turbines are almost exclusively used for commercial power generation, although some vertical axis wind turbine designs have been developed. The mechanism to capture the energy and then transmit and convert it into electrical power involves several stages, components and controls. Wind turbines can be broadly classified into two types according to capacity – small wind turbines (up to 100 kW) and large wind turbines. Small wind turbines are used for grid, off-grid and mini-grid applications, while large wind turbines are used almost exclusively for interconnected grid power supply. Figure A2.1 depicts both a horizontal wind turbine and a typical large-scale wind farm arrangement.

Figure A2.1: Wind Turbine Schematics



Source: DOE/EPRI.

Wind Turbine Technology Description

Major components of horizontal axis wind turbine include the rotor blades, generator aerodynamic power regulation, yaw mechanism and the tower. The rotor blade is critical, as it captures the wind energy and converts it into the torque required to spin the generator. One measure of an aerodynamically efficient blade design is the weight/swept area ratio; this parameter can be used to compare efficiency across machines of similar design and capacity. Blade lengths increase with the size of the wind turbines, as longer lengths result in more energy capture. Longer blades require higher strength and lower mass, leading to common use of composite materials including carbon epoxy and fiber-reinforced plastic.

Kinetic energy captured by the rotor blades is transferred to the generator through the transmission shaft. The shaft is coupled directly or via a gearbox mechanism to the armature of either an asynchronous (induction) or synchronous generator. A wind turbine with an induction generator comes with gearboxes, which convert the cut-in to cut-out speed variations to one, two or three speeds of the generator. In an induction generator the generator revolutions increase or decrease with the wind speed. For example, a two-speed generator has 4 poles at 1,500 (RPM) and 6 poles at 1,000 RPM. Wind turbines configured with synchronous generators have continuous speed variation according to the speed of the wind. Synchronous machines have no gearbox and can be connected to the grid at almost any wind speed. Synchronous machines provide great operational flexibility and good power quality, but are expensive because of the need for power electronics. Both asynchronous and synchronous machines can operate over a significant range of wind speeds.

Wind turbine technology continues to evolve, with the doubly-fed induction generator (DFIG) direct drive (DD) synchronous machines under development. The DFIG incorporates most of the benefits of the variable speed drive system and has the advantage of minimal losses because of the fact that only a third of the power passes through the converter. DD synchronous machines have multi pole design for a wide speed range. Power electronics facilitates such wide speed ranges. All these generator developments rely on power electronics to control power quality. The cost of power electronics is falling, resulting in reduction of capital cost of the variable speed drives and thus lower generation costs for electricity produced by wind. The other major improvement is the increasing size and performance of wind turbines. From machines of just 25 kW 20 years ago, the commercial range sold today is from 600 up to 2,500 kW. In 2003 the average capacity of new turbines installed in Germany was 1,390 kW. With development of larger individual turbines, the required capacity of a wind farm can be met with fewer individual turbines, which has beneficial effects on both investment and O&M costs.

Aerodynamic power regulation is a common feature of modern wind turbines allowing control of output power by mechanical adjustment of the rotational speed, especially at higher wind speeds. In a *pitch-controlled* wind turbine, the turbine's electronic controller checks the power output of the turbine several times per second. When the power output becomes too high, it sends a signal to the blade pitch mechanism, which immediately pitches (turns) the rotor blades slightly out of the wind. Conversely, the blades are turned back into the wind whenever the wind drops again. *Stall,* or *passive control* through the blade design itself, requiring no moving parts. The profile of the rotor blade is aerodynamically designed to ensure that the moment the wind speed becomes too high; it creates turbulence on the side of the rotor blade, which is not facing the wind. Although power regulation through stall control avoids complex control systems, it represents a very complex aerodynamic design problem, including avoiding the problem of stall-induced vibrations in the structure of the turbine. Finally, an *active stall* control mechanism is being used in larger (1 MW and above) wind turbines. At low wind speeds, the machines will usually be programed to pitch their blades much like a pitch-controlled machine. However, when the machine reaches its rated power and the generator is about to be overloaded, the machine will pitch its blades in the opposite direction from what a pitch-controlled machine does. This is similar to normal stall power control, except that the whole blade can be rotated backwards (in the opposite direction as is the case with pitch control) by a few (3-5) degrees at the nominal speed range in order to give better rotor control. In other words, it will increase the angle of attack of the rotor blades in order to make the blades go into a deeper stall, thus wasting the excess energy in the wind. The result is known as the "deep stall" effect, which leads to the power curve bending sharply to a horizontal output line at nominal power and keeping this constant value for all wind speeds between nominal and cut-out.

The wind tower is another critical wind turbine component, as it must provide the structural frame necessary to accommodate the external forces due both to the wind and the motions of the various components of a wind turbine. The tower must be designed to withstand vibrations as well as static and dynamic loads. The most important consideration in tower design is to avoid natural frequencies near rotor frequencies. The two most common tower designs are *lattice* and *tubular*. A *lattice tower* is cheaper compared to the tubular tower and, being usually a bolted structure, is easier to transport. However, tubular towers have several advantages over lattice towers. Not only is a tubular tower stiffer than a lattice tower, thus better able to withstand vibrations, it also avoids the many bolted connections of a lattice tower that require frequent checking and tightening. Moreover, tubular tower allow full internal access to the nacelle.

As wind turbines increase in size and height, tower design is becoming critical. Only recently the conventional wisdom was that traditional towers taller than 65 m presented significant logistical problems and result in high costs. However, hub heights of 100 m or more for commercial wind turbines are becoming more frequent (GE's 2.3 MW turbine has a hub height of 100 m), and efforts are under way to develop innovative construction materials and erection concepts to allow these tall turbine structures to be erected without adverse cost impact.

A final mechanical design feature is yaw control. The yaw control continuously orients the rotor in the wind direction. Large wind turbines mostly have active yaw control, in which the yaw bearing includes gear teeth around its circumference. A pinion gear on the yaw drive engages with those teeth, so that it can be driven in any direction. The yaw drive normally consists of electric motors, speed reduction gears and a pinion gear. This is controlled by an automatic yaw control system with its wind direction sensor usually mounted on the nacelle of the wind turbine.

Wind turbine technology is being continuously improved worldwide, resulting in better performance, more effective land utilization, and greater grid integration. Technology development in the form of larger size wind turbines, larger blades, improved power electronics and taller towers is noteworthy, resulting in dramatic improvement. Averaging 25 kW just 20 years ago, the commercial range sold today is typically from 600 up to 2,500 kW.

Small Wind Turbines

Small wind turbines are mostly used for charging batteries or supplying electrical loads in DC (12 or 24 V), bus-based off-grid power systems. However, when used in conjunction with a suitable DC-AC inverter and a battery bank, the turbine can also deliver power to a mini-grid. A particularly attractive configuration is small wind turbines in the 5 kW generating AC power for village-scale mini-grids.

As with larger wind turbines, almost all small wind turbines are horizontal axis machines with the same basic components as their larger brethren. The major components of a typical horizontal axis small wind turbine include:

- A simple alternator which converts the rotational energy of the rotor into three-phase AC electricity. The alternator utilizes permanent magnets and has an inverted configuration in that the outside housing (magnet) rotates, while the internal windings and central shaft are stationary;
- Turbine blades and a rotor system, usually comprising three fiberglass blades;
- A simple lattice tower and tail assembly, the latter composed of a tail boom and the tail fin which keeps the rotor aligned into the wind at wind speeds below the limiting, or cut-out, wind speed. At wind speed exceeding cut-out the tail turns the rotor away from the wind to limit its speed; and
- A power controller unit which serves as the central connection point for the electrical portion of the system and regulates the charging and discharging of the battery bank and incorporates protection features including load dumping and turbine protection.

Wind Turbine Economic and Environmental Assessment

The key design and performance assumptions regarding wind turbines with output capacities from 0.3 kW to 100,000 kW are shown in Table A2.1. We selected an average capacity factor of 30 percent across the board, even though capacity factors are highly dependent on wind speeds at a given location and can vary from 20 percent to 40 percent. The uncertainty analysis performed will accommodate a broader rage of capacity factor.

Table A2.1: Wind Turbine Design Assumptions

Capacity	*300 W*	*100 kW*	*10 MW*	*100 MW*
Capacity Factor (%)	25	25	30	30
Life Span (year)	20	20	20	20
Annual Gross Generated Electricity (MWh)	0.657	219	26,280	262,800

As with most other RE systems, the direct environmental impact in terms of air or water emissions is nil. There are other environmental impacts including noise, bird mortality and aesthetic/visual impact. All of these impacts are highly location-specific and considerable mitigation is possible with the careful design of wind turbines and their deployment. The magnitude of costs associated with these impacts or their mitigation will differ greatly from region to region, and, therefore, we have elected not to attempt to quantify them in the economic assessment.

Table A2.2 shows the capital costs for different size of wind power projects.

Table A2.2: Wind Turbine Capital Costs in 2005 (US$/kW)

Items	*300 W*	*100 kW*	*10 MW*	*100 MW*
Equipment	3,390	2,050	1,090	940
Civil	770	260	70	60
Engineering	50	50	40	40
Erection	660	160	100	80
Process Contingency	500	260	140	120
Total	**5,370**	**2,780**	**1,440**	**1,240**

Table A2.3 shows the levelized generation costs given the performance parameters of Table A2.1 and considering average O&M costs for wind power projects.

Table A2.3: Wind Turbine Generating Costs in 2005 (US¢/kWh)

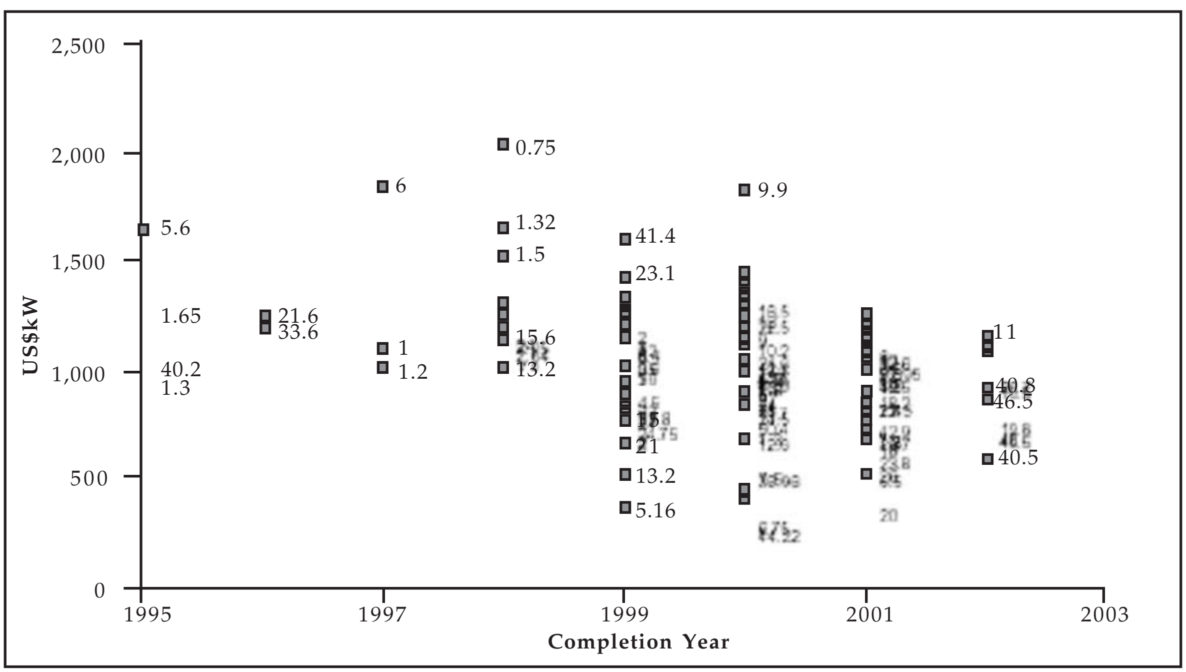
Items	*300 W*	*100 kW*	*10 MW*	*100 MW*
Levelized Capital Cost	26.18	13.55	5.85	5.04
Fixed O&M Cost	3.49	2.08	0.66	0.53
Variable O&M Cost	4.90	4.08	0.26	0.22
Fuel Cost	0.00	0.00	0.00	0.00
Total	**34.57**	**19.71**	**6.77**	**5.79**

For small wind turbines the periodic cost of battery replacement was distributed (assuming five-year average battery life) over system life span and included in the variable costs.

Future Wind Turbine Costs

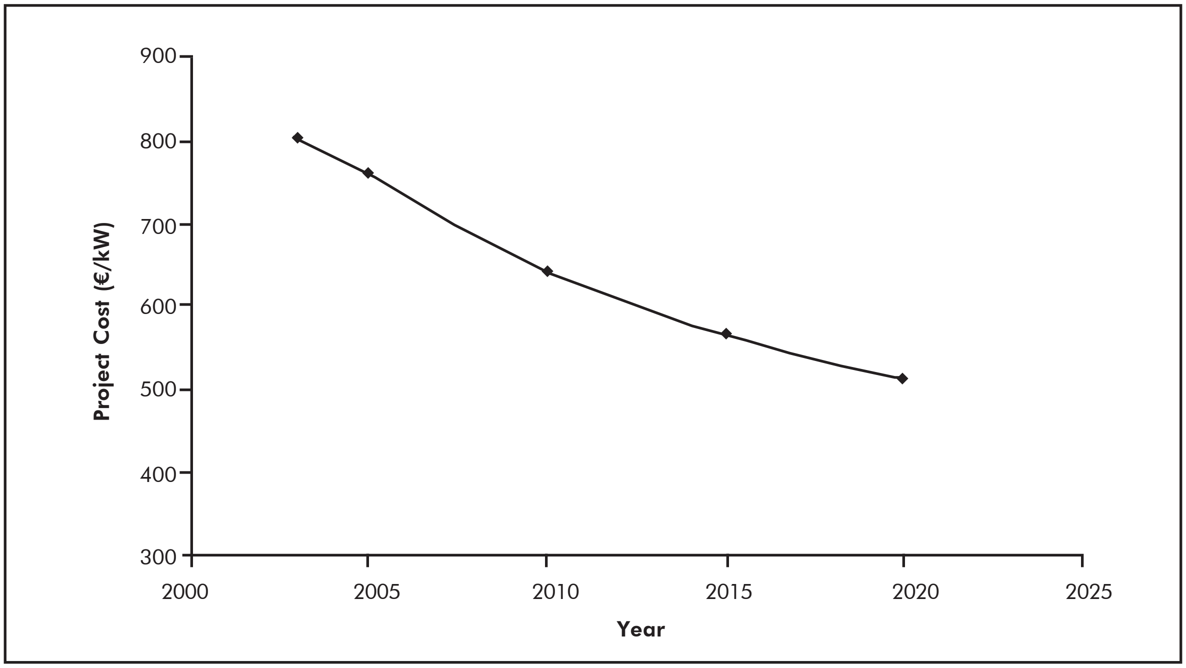
The costs of wind generators have been coming down over the years, as shown in Figure A2.2. Most analysts expect this trend to continue in future, with reductions of as much as 36 percent in capital costs by 2020 forecast by the EWEA (Figure A2.3).

Figure A2.2: Wind Power Project Cost Trends



Source: Asia Alternative Energy Programme (ASTAE).

Figure A2.3: Wind Power Cost Projections



Source: European Wind Energy Association.

EPRI also had made cost projections for the capital cost of wind power. As per the EPRI projections, the costs for a 10 MW plant would be about US$1,080/kW in 2010 and US$980/kW in 2015 in terms of US$1,999. In case of a 100 MW plant, the costs projections are about US$850/kW in 2010, and US$750/kW in 2015 in US$1,999 terms.[28] We note, however, that the costs in many countries are lower than the EPRI costs. For example, in India, the costs are about US$1,000/kW, while the costs in Germany, Denmark and Spain are about €900 to 1200/kW in 2002.[29] Thus, in our forecast of future wind turbine costs, we have elected to use the EWEA cost projections as a lower bound and use the EPRI cost projections as an upper bound.[30]

Uncertainty Analysis

Uncertainty analysis was performed to place bounds on both the inherent uncertainty stemming from a stochastic resource such as wind as well as the more familiar uncertainties as regards forecast capital and other costs. The variation of the wind resource and, thus, wind turbine capacity factor from site to site can be generally captured by using the Weibull

[28] *Renewable Energy Technical Assessment Guide – TAG-RE: 2004, EPRI, 2004.*
[29] *Wind Energy – The Facts, Vol. 2: Costs and Prices, European Wind Energy Association, 2003.*
[30] *We do this mathematically by using the GDP deflator to change the projection in 1999 dollar terms to 2004 dollar terms.*

distribution. Since wind energy generation is a function of the wind speed variation as well as the power curve of the wind turbine, the capacity factor varies over time for a given location and for a specific time from location to location. In the present analysis, the range of location-to-location variation of the capacity factor is used for the uncertainty analysis and is captured by letting the capacity factor range from 20 percent to 40 percent, with 30 percent as an average value. The uncertainty in projected capital costs, described above and shown in Table A2.4, is included along with an assumed variability in O&M costs of ±20 percent. Table A2.5 shows the results of our uncertainty analysis for wind power generation costs.

Table A2.4: Present and Projected Wind Turbine Capital Costs (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	4,820	5,370	5,930	4,160	4,850	5,430	3,700	4,450	5,050
100 kW	2,460	2,780	3,100	2,090	2,500	2,850	1,830	2,300	2,650
10 MW	1,270	1,440	1,610	1,040	1,260	1,440	870	1,120	1,300
100 MW	1,090	1,240	1,390	890	1,080	1,230	750	960	1,110

Table A2.5: Present and Projected Wind Turbine Generation Costs (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	30.1	34.6	40.4	27.3	32.0	37.3	25.2	30.1	35.1
100 kW	17.2	19.7	22.9	15.6	18.3	21.3	14.4	17.4	20.2
10 MW	5.8	6.8	8.0	5.0	6.0	7.1	4.3	5.5	6.5
100 MW	5.0	5.8	6.8	4.2	5.1	6.1	3.7	4.7	5.5

Annex 3

SPV-wind Hybrid Power Systems

Another promising approach to meeting rural energy needs at the village level is PV-wind hybrid systems using small wind turbines. Such a hybrid configuration is a viable alternative to expensive engine-generator sites for serving isolated mini-grids. The hybrid design approach also takes advantage of the differential availability of the solar resource and the wind resource, allowing each renewable resource to supplement the other, increasing the overall capacity factor.[31]

PV-wind hybrid systems consist of the following components:

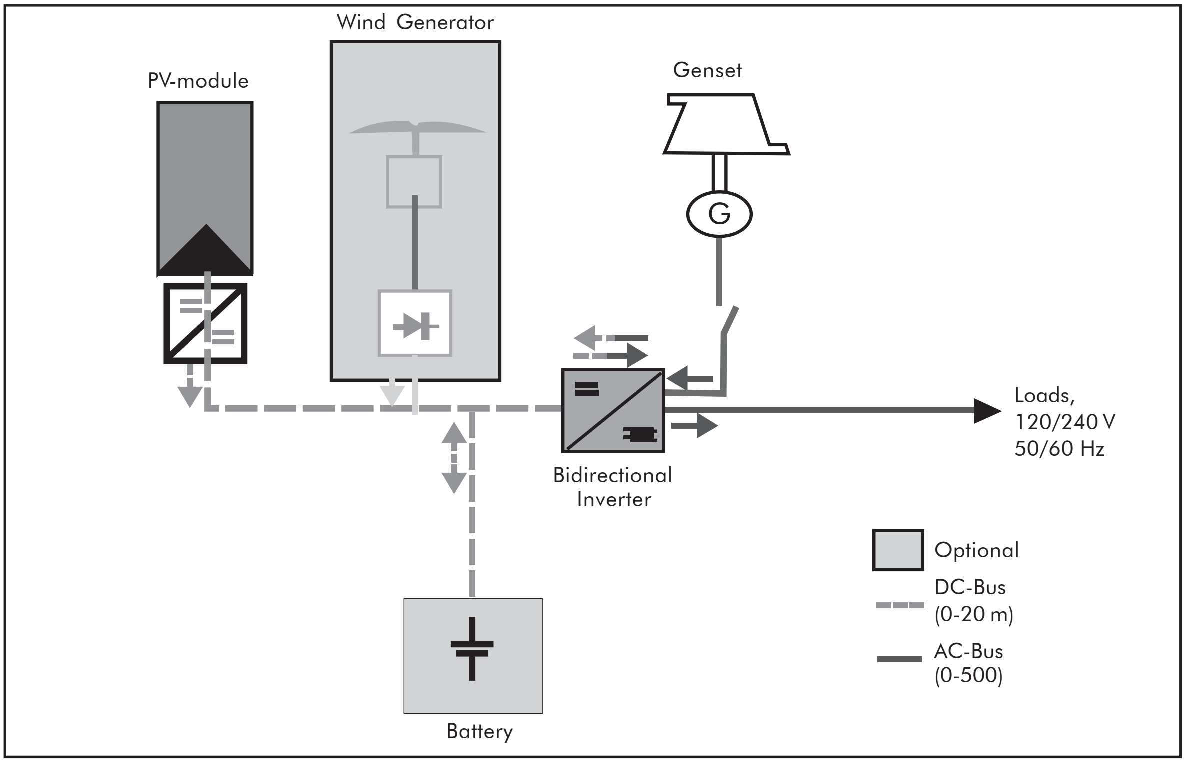
- One or more wind turbines (common capacity ranges from 5 to 100 kW);
- PV modules (capacity varies depending on load requirement and the nature of the control unit);
- Control unit (commonly known as inverter-cum-controller);
- Storage system (typically battery banks);
- Consumer load;
- Additional controllable or dump load; and
- Additional provision for connecting diesel generating sets.

The actual systems vary widely and depend on conditions specific to individual sites. The hybrid system architecture mainly depends on the nature of the inverter-cum-controller. The two most common system types are:

- A small AC mini-grid with DC-coupled components. Originally, this technology was created in order to provide AC power from DC sources and to use both DC and AC sources to charge batteries. Multiple AC generators are coupled on the AC side, and a suitable control strategy for generation and power delivery using a bidirectional inverter is implemented. The inverter can receive power from DC and AC generators and also works as a battery charger. The common power range is from 0.5 to 5 kW and DC voltage is 12, 24, 48 or 60 V. The system layout is shown in Figure A3.1; and
- Modular AC-coupled systems. Larger loads (3 to 100 kW) call for more traditional AC-coupled systems with all of the flexibility inherent to a more conventional grid arrangement, but still incorporating battery storage and an optional DC bus (Figure A3.2). This arrangement requires coupling of all generators and consumers on the AC side. Since these kinds of decentralized systems are grid compatible in their power characteristics, they can be deployed so that broader interconnection to other mini-grids

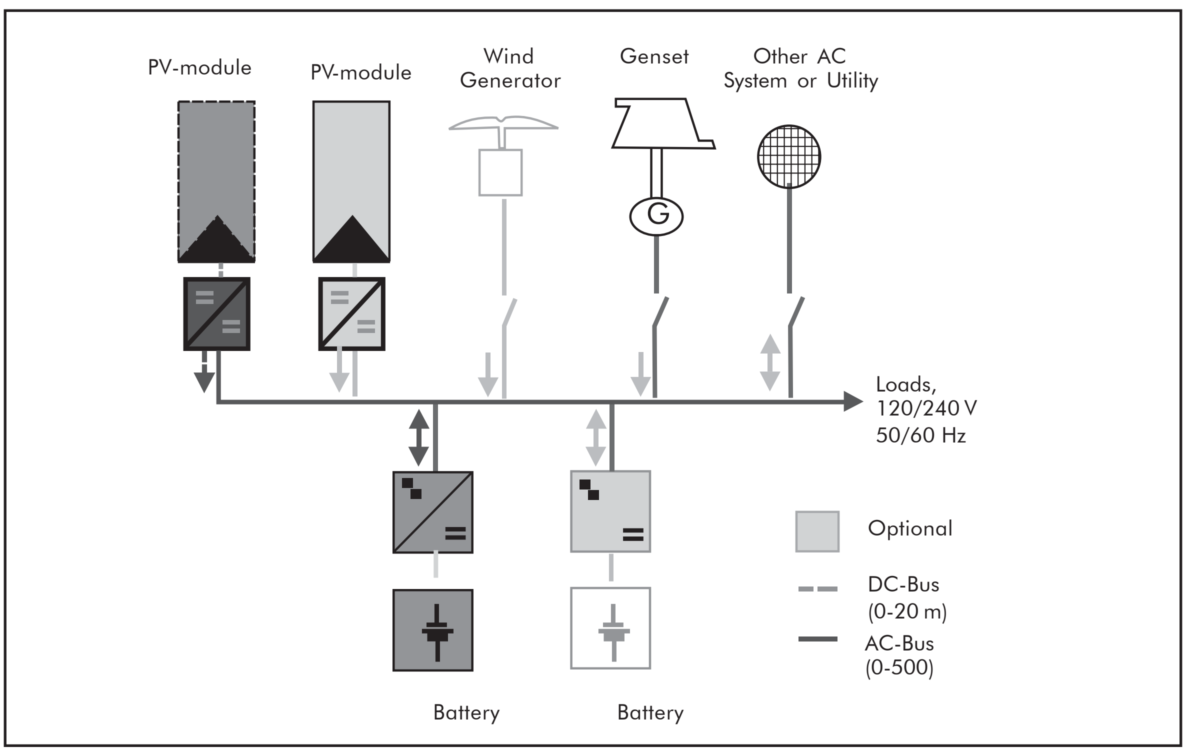
[31] *Numerous studies, including SWERA (Solar-Wind Energy Resource Assessment, UNDP), have observed this reverse coincidence of solar insolation and high wind speeds for many parts of the developing world.*

Figure A3.1: Mixed DC- and AC-coupled PV-wind Hybrid Power System



Source: DOE/EPRI.

Figure A3.2: Pure AC PV-wind Hybrid Power System



Source: DOE/EPRI.

or the national grid is possible in future. Such a structure allows maximum electrification flexibility in initially supplying rural villages with the power for basic needs and, subsequently, scaling up the rural power available through progressive interconnection.

Solar-wind hybrid systems have been installed for a variety of applications around the world. Successful deployments include island mini-grids, remote facilities and small buildings. Typical applications include water pumping, communications and hospitals.

Economic assessment

For the economic assessment, we assume a system life of 20 years and a capacity factor of 30 percent. We note that the capital costs of hybrid systems are highly dependent on the system configuration and the individual capacities of the SPV and wind energy systems. We have set typical costs for two size ranges – 300 W and 100 kW – as shown in Table A3.1. These capital costs are calculated based on Indian small PV-wind hybrid systems' product data.[32]

Table A3.1: PV-wind Hybrid Power System 2005 Capital Costs (US$/kW)

Items	*300 W*	*100 kW*
Equipment	4,930	3,680
Civil	460	640
Engineering	30	130
Erection	390	450
Process Contingency	630	520
Total	**6,440**	**5,420**

Table A3.2 shows the results of PV-wind hybrid system generating costs calculated in line with the methodology described in Annex 2. Total O&M cost is assumed to be 2.5 percent of capital cost and is then divided into fixed and variable portions. Variable O&M cost also includes battery replacement aspect as per the SPV system.

[32] *See M/s. Auroville Wind Systems, particularly the 1.5 kW and 5 kW wind turbines with 130 Wp and 450 W_p of SPV modules.*

Table A3.2: PV-wind Hybrid Power System 2005 Generating Costs (US¢/kWh)

Items	*300 W (CF 25%)*	*100 kW (CF 30%)*
Levelized Capital Cost	31.40	22.02
Fixed O&M Cost	3.48	2.07
Variable O&M Cost	6.90	6.40
Fuel Cost	0.00	0.00
Total	**41.78**	**30.49**

The PV-wind hybrid systems have a niche market in remote areas far from economical grid extension. The costs of these hybrid systems are projected to be reduced consistent with the cost projections for the individual SPV and wind energy systems.

Uncertainty Analysis

As with the individual SPV and wind technologies, the key uncertainties affecting delivered generation costs revolve around expected capacity factor and capital cost variability. Since the hybrid systems combine two resources, the range over which capacity factor can vary will be smaller than with the individual technologies. We assume a capacity factor in the range from 25 percent to 40 percent, with 30 percent as probable value. We carry forward the uncertainties in projected capital costs, shown in Table A3.3, and assume a ± 20 percent variation in O&M costs in order to estimate the band of generation cost estimates in the years 2010 and 2015 shown in Table A3.4.

Table A3.3: PV-wind Hybrid Power System Projected Capital Costs (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	5,670	6,440	7,210	4,650	5,630	6,440	3,880	5,000	5,800
100 kW	4,830	5,420	6,020	4,030	4,750	5,340	3,420	4,220	4,800

Table A3.4: PV-wind Hybrid Power System Projected Generating Costs (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	36.1	41.8	48.9	31.6	37.8	44.5	28.1	34.8	40.9
100 kW	26.8	30.5	34.8	23.8	27.8	31.7	21.4	25.6	29.1

Annex 4

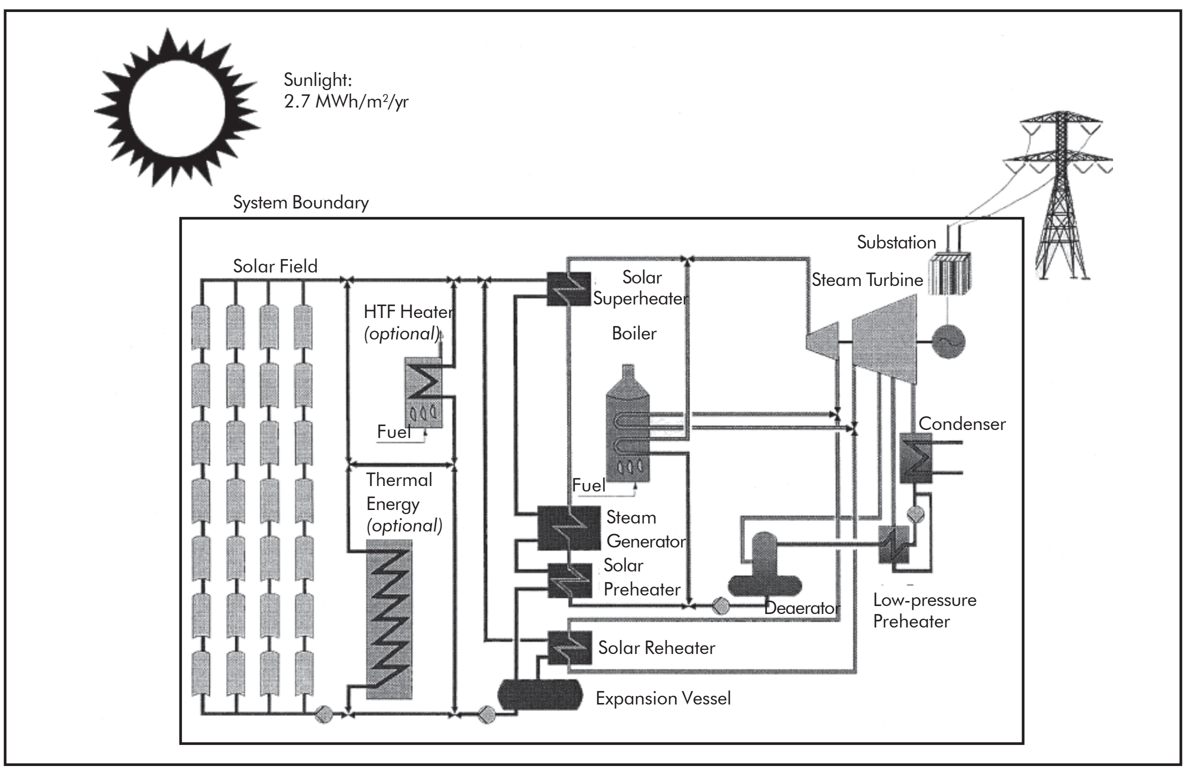
Solar-thermal Electric Power Systems

Solar-thermal power generation technologies comprise several technically viable options for concentrating and collecting solar energy in densities sufficient to power a heat engine. These include parabolic dish collectors, parabolic trough collectors and central receivers. Only the parabolic trough configuration has found commercial application. Although several large solar thermal electric projects are in the planning stages, and other options are in the research and development stage, the amount of installed solar thermal electric capacity around the world is negligible compared with SPV or wind turbines. Only the parabolic trough-based solar-thermal electric system is considered for the present study.

Technology Description

The parabolic trough concentrator is essentially a trough lined with reflective material. The concentrators track the sun with a single-axis mechanical tracking system oriented east to west. The trough focuses the solar insolation on a receiver located along its focal line. A collector field consists of large number of concentrators sufficient to generate the required amount of thermal energy. A heat transfer fluid (or thermic fluid), typically high temperature oil, is circulated via pipes to the concentrators and the heated fluid is then pumped to a central power block, where it exchanges its heat to generate steam (Figure A4.1). The power block consists of steam turbine and generator, turbine and

Figure A4.1: Solar-thermal Electric Power Plant Schematic



Source: DOE/EPRI.

generator auxiliaries, feed-water and condensate system. A variant of this technology is the direct solar steam (DSS) concentrator, which eliminates the heat transfer loop by generating steam directly at the concentrator. A solar thermal electric power plant can also have thermal storage, which improves the capacity factor but increases the cost. While both options are analyzed here, the present trend is to use the solar thermal plant without thermal storage in large, grid-connected applications.

Economic Assessment

The design and performance assumptions for solar thermal electric power projects are listed in Table A4.1. We assessed two configurations (with and without storage) but only one size range – 30 MW – which is typical of several projects under development in Spain and the MENA region.[33] The capacity factor for solar thermal power projects is dependent on the availability of solar resource, especially in the case of plants without storage. A capacity factor of 20 percent was used for analysis of plants without thermal storage and 54 percent was used for analysis of plants with thermal storage.[34]

Table A4.1: Solar-thermal Electric Power System Design Assumptions

Capacity	*30 MW (without thermal storage)*	*30 MW (with thermal storage)*
Capacity Factor (%)	20	50
Life Span (year)	30	30
Gross Generated Electricity (GWh/year)	52	131

Table A4.2 provides a capital cost breakdown based on NREL data for solar thermal power projects with and without thermal storage, exclusive of land costs.

[33] *See, for example, Project Information Document (PID) – Arab Republic of Egypt Solar Thermal Power Project. Report No. AB662 and Solar Thermal Power 2020: Exploiting the Heat from the Sun to Combat Climate Change, Greenpeace 2004.*

[34] *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts, NREL, NREL/SR-550-34440, October 2003.*

Table A4.2: Solar-thermal Electric Power System 2005 Capital Costs (US$/kW)

Items	*30 MW (without thermal storage)*	*30 MW (with thermal storage)*
Equipment	890	1,920
Civil	200	400
Engineering	550	920
Erection	600	1,150
Process Contingency	240	460
Total	**2,480**	**4,850**

Harmful emissions and pollution impacts of solar thermal power generation are nil. Water requirements, mainly for the cooling towers, is an issue, as most potential sites for solar thermal power generation are in arid or desert areas.

The generating cost (Table A4.3) is estimated using the capital costs in Table A4.2 and based on the performance parameters mentioned in Table A4.1. O&M costs are taken from NREL data.

Table A4.3: Solar-thermal Electric Power 2005 Generating Costs (US¢/kWh)

Items	*30 MW (without thermal storage)*	*30 MW (with thermal storage)*
Levelized Capital Cost	13.65	10.68
Fixed O&M Cost	3.01	1.82
Variable O&M Cost	0.75	0.45
Fuel Cost	0.00	0.00
Total	**17.41**	**12.95**

Future System Cost Projections

The cost assessment report by NREL forecasts the possible cost reductions in the solar thermal power generation based on an analysis of technology improvement projections and scale-up. The projected reduction (15 percent by 2010 for the nonstorage configuration and 33 percent by 2015 for the storage case) is a result of lower solar collector system and mirror costs as well as cheaper storage costs due to technological improvements and economies of scale. These cost projections are shown in Table A4.4 and are taken forward into the uncertainty analysis.

Table A4.4: Solar-thermal Electric Power Capital Costs Projections (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
30 MW (without storage)	2,290	2,480	2,680	1,990	2,200	2,380	1,770	1,960	2,120
30 MW (with storage)	4,450	4,850	5,240	3,880	4,300	4,660	3,430	3,820	4,140

Uncertainty Analysis

Solar thermal power plant capacity factor varies according to location; however, locating these large expensive plants in areas of high solar radiation will minimize any uncertainty associated with capacity factor. For our uncertainty analysis, we will allow the capacity factor to vary between 18 and 25 percent with 20 percent as the probable value for plants without storage and no variation in case of the plants with storage.

Our uncertainty analysis for estimations of generation cost further assumes the capital cost variability shown in Table A4.4 and an assumed ±20 percent variation in operating costs. The results are shown in Table A4.5.

Table A4.5: Solar-thermal Electric Power Generating Costs Projections (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
30 MW (without storage)	14.9	17.4	21.0	13.5	15.9	19.0	12.4	14.5	17.3
30 MW (with storage)	11.7	12.9	14.3	10.5	11.7	12.9	9.6	10.7	11.7

Annex 5
Geothermal Power Systems

Geothermal energy arises from the heat deep within the earth. Worldwide, the most accessible geothermal resources are found along the boundaries of the continental plates, in the most geologically active portions of the earth.

Two primary types of geothermal resources are being commercially developed – naturally-occurring hydrothermal resources and engineered geothermal systems. Hydrothermal reservoirs consist of hot water and steam found in relatively shallow reservoirs, ranging from a few hundred to as much as 3,000 m in depth. Hydrothermal resources are the current focus of geothermal development because they are relatively inexpensive to exploit. A hydrothermal resource is inherently permeable, which means that fluids can flow from one part of the reservoir to another, and can also flow into and from wells that penetrate the reservoir. In hydrothermal resources, water descends to considerable depth in the crust where it is heated. The heated water then rises until it becomes either trapped beneath impermeable strata, forming a bounded reservoir, or reaches the surface as a hot spring or steam vent. The rising water brings heat from the deeper parts of the earth to locations relatively near the surface.

The second type of geothermal resource is "engineered geothermal systems (EGS)," sometimes referred to as "Hot Dry Rocks (HDR)." These resources are found relatively deep in masses of rock that contain little or no steam, and are not very permeable. They exist in geothermal gradients, where the vertical temperature profile changes are greater than average (>50°C/km). A commercially attractive EGS would involve prospecting for hot rocks at depths of 4,000 m or more. To exploit the EGS resource, a permeable reservoir must be created by hydraulic fracturing, and water must be pumped through the fractures to extract heat from the rock. Most of the EGS/HDR projects to date have been essentially experimental; but there is future commercial potential.

Commercial exploitation of geothermal systems in developing economies is constrained by two factors:

- Geothermal exploration, as with most resource extraction ventures, is inherently risky. Geothermal power systems are difficult to plan because what lies beneath the ground is only poorly understood at the onset of development. It may take significant work to prove that in a particular field, and many exploration efforts have failed altogether. The exception is areas with many hydrothermal manifestations (for example, geysers, mud pots), such as The Geysers in the United States and a number of fields in Indonesia and Central America; and
- Both exploration and development require substantial specialized technical capacity that is not usually available in developing countries unless there has been focused local

capacity-building or an influx of specialists and creation of local teams. Countries where such teams have been successful or are emerging include the Philippines, Mexico, Indonesia, Kenya and El Salvador.

Technology Description

For developing country applications, we assume that geothermal systems will be available in small sizes suitable for mini-grid applications and a larger size suitable for grid-electric applications:

- For mini-grid applications, 200 kW binary hydrothermal; and
- For grid applications, a 20 MW binary hydrothermal, and a 50 MW flash hydrothermal.

Figure A5.1 provides a schematic for a binary hydrothermal electric power system of indeterminate size. Figure A5.2 provides a schematic for a flash hydrothermal unit.

Figure A5.1: Binary Hydrothermal Electric Power System Schematic

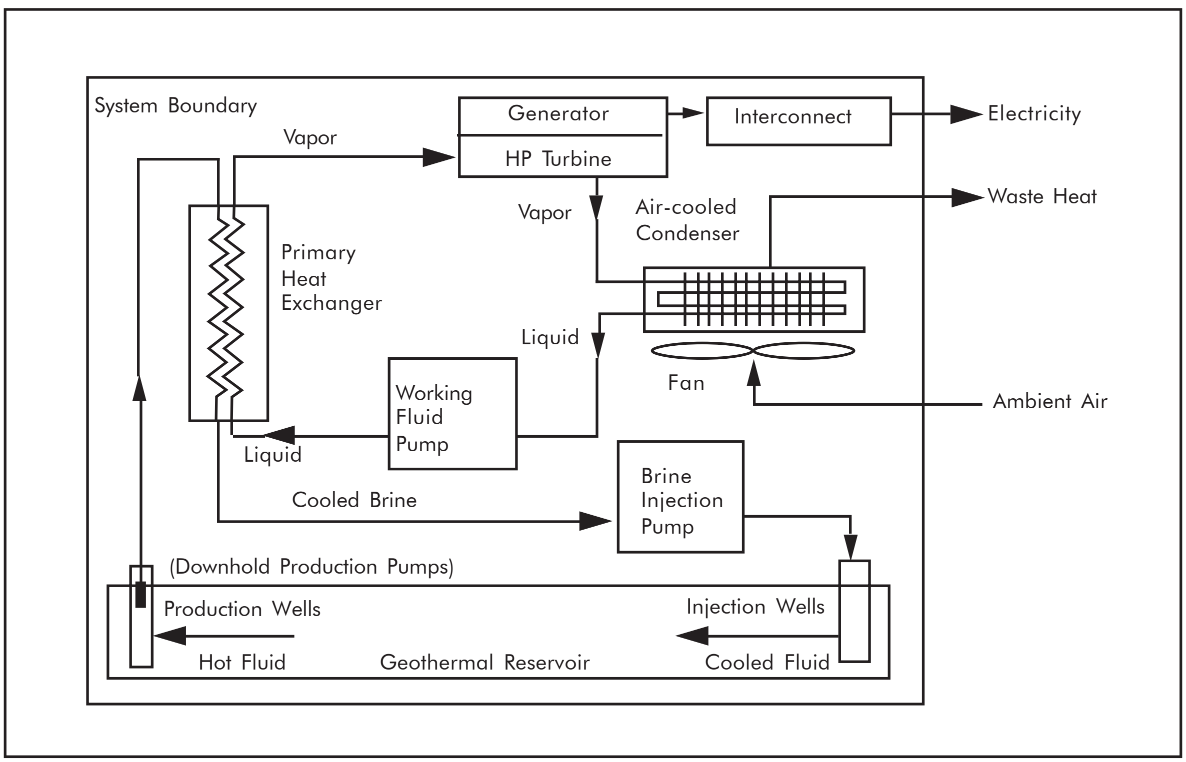
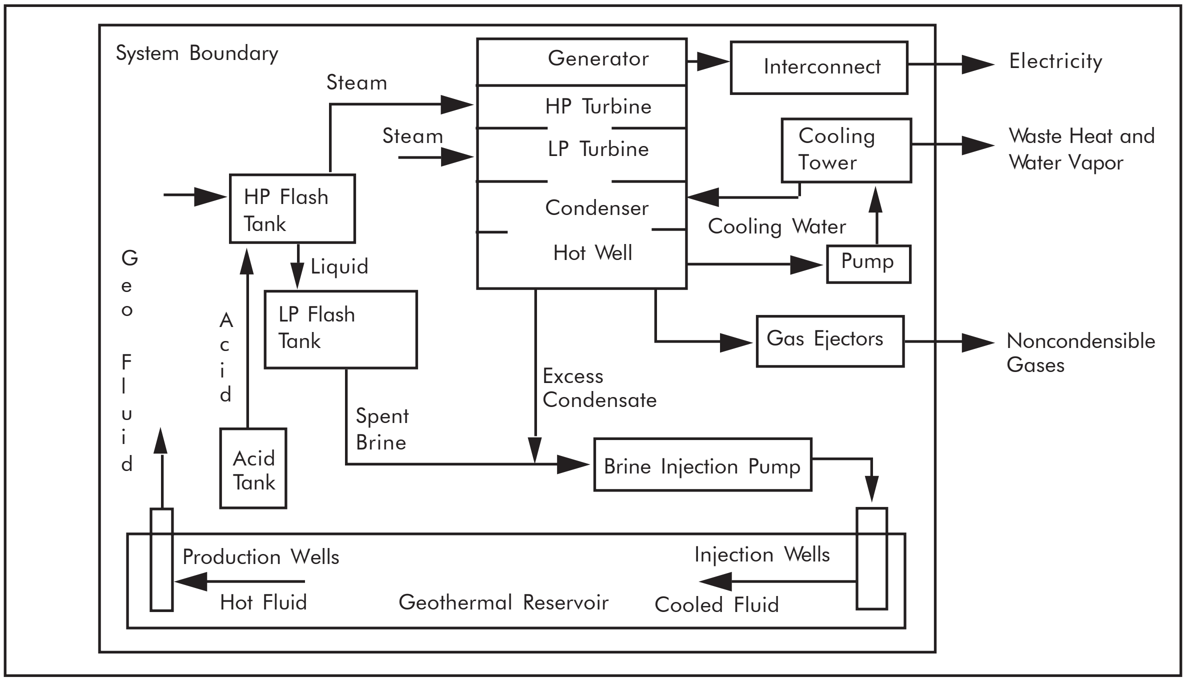


Figure A5.2: Flash Hydrothermal Electric Power System



Source: DOE/EPRI.

Environmental and Economic Assessment

Table A5.1 provides the basic design and performance assumptions we associate with the binary hydrothermal and flash hydrothermal electric power project shown in Figures A5.1 and A5.2.

Table A5.1: Basic Characteristics of Geothermal Electric Power Plants

	Binary Hydrothermal	*Binary Hydrothermal*	*Flash Hydrothermal Plants*
Capacity	200 kW	20 MW	50 MW
Capacity Factor (%)	70	90	90
Geothermal Reservoir Temperatures	125-170°C	125-170°C	>170°C
Life Span (year)*	20	30	30
Net Generated Electricity (MWh/year)	1,230	158,000	394,200

** Although the plant life span is 20-30 years, wells will be depleted and new wells will be drilled much before that time. An allowance for this additional drilling is included in the generating cost estimates.*

Large geothermal plants can generally operate as base-loaded facilities with capacity factors comparable to or higher than conventional generation (90 percent CF). Binary plants in mini-grid applications will have lower capacity factors (30-70 percent), due mainly to limitations in local demand. We consider only the high capacity factors for small binary systems, as they will be the most cost-effective. The viability of the geothermal resource is dictated by local geological conditions. For this report, we assume that hot water resources can be categorized as being either high temperature (>170°C) or moderate temperature (<170°C and >125°C).

Because they operate in a closed-loop mode, binary plants have no appreciable emissions, except for very slight leakages of hydrocarbon working fluids. Some emissions of H_2S are possible (no more than 0.015 kg/MWh), but H_2S removal equipment can easily eliminate any problem. CO_2 emissions are small enough to make geothermal power a low CO_2 emitter relative to fossil fuel plants.

Table A5.2 shows the conventional breakdown of geothermal capital costs into the standard cost components used in this study.

Table A5.2: Geothermal Electric Power Plant 2005 Capital Costs (US$/kW)

Items	*200 kW Binary Plant*	*20 MW Binary Plant*	*50 MW Flash Plant*
Equipment	4,350	1,560	955
Civil	750	200	125
Engineering	450	310	180
Erection	1,670	2,030	1,250
Total	**7,220**	**4,100**	**2,510**

Table A5.3 shows a breakdown in the capital cost estimates organized by the sequence of development activities, for example, exploration costs (to discover first productive well), confirmation costs (additional drilling to convince lenders that the site has commercial capability, main wells costs (remaining wells drilled during construction phase) and remaining costs associated with construction of the power plant itself.

Table A5.3: Geothermal Capital Costs by Development Phase (US$/kW)

Items	*200 kW Binary Plant*	*20 MW Binary Plant*	*50 MW Flash Plant*
Exploration	300	320	240
Confirmation	400	470	370
Main Wells	800	710	540
Power Plant	4,250	2,120	1,080
Other	1,450	480	280
Total	**7,200**	**4,100**	**2,510**

For the 200 kW binary projects, we set the contingency cost quite high, because very few projects of this size have been built. It is likely that the risk associated with such small projects would be unattractive for commercial firms, and thus a public sector entity would be the most likely implementing agency for such systems.

Table A5.4 shows the results of converting capital cost into generating cost, in line with Annex 2. O&M costs are stated as fixed costs here because the truly variable costs, for example, lubricants, are very low. Most of the O&M is in labor for the power plant. O&M for binary systems includes replacement of downhole production pumps at three to four year intervals.

Table A5.4: Geothermal Power Plant 2005 Generation Costs (US¢/kWh)

Items	*200 kW Binary Plant*	*20 MW Binary Plant*	*50 MW Flash*
Levelized Capital Cost	12.57	5.02	3.07
Fixed O&M Cost	2.00	1.30	0.90
Variable O&M Cost	1.00	0.40	0.30
Total	**15.57**	**6.72**	**4.27**

Future Price of Geothermal Electric Power Plants

It is difficult to predict future prices for geothermal power systems. There have been long-term trends (since 1980) of price declines, of about 20 percent per decade for power plants, and 10 percent per decade for geothermal production and injection wells (relative to petroleum wells). Recently, variations in oil prices have been so large that they obscure any useful projections in cost reductions of geothermal exploration or development. In fact, the recent increases in oil prices have driven up the apparent cost of geothermal wells in the United States in the past year. We assume a flat cost trajectory for this technology, as shown in Table A5.5.

Table A5.5: Geothermal Power Plant Capital Costs Projections (US$/kW)

	2005	*2010*	*2015*
200 kW Binary Plant	7,220	6,580	6,410
20 MW Binary Plant	4,100	3,830	3,730
50 MW Flash Plant	2,510	2,350	2,290

Many industry analysts contend that geothermal R&D and improved economies of scale due to large-scale deployment can help the industry resume the downward trends seen since 1980. There may also be opportunities to locate binary systems in areas with shallow reservoirs, where the costs of drilling and well maintenance may be lower. The section on uncertainty analysis attempts to reflect this improvement potential through the quantification of a "minimum" capital cost. For the purpose of uncertainty analysis below, we draw from the EPRI work on RE to establish a range of expected capital cost reductions (generally, -20 percent and +10 percent) over the study period.

Uncertainty Analysis Future Price of Geothermal Electric Power Plants

The cost of geothermal power plants can be quite variable, depending on the specific resource that is being used. This fact is reflected in the range of capital costs presented in Table A5.6.

Table A5.6: Geothermal Power Plant Capital Costs Uncertainty Range (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
200 kW Binary	6,480	7,220	7,950	5,760	6,580	7,360	5,450	6,410	7,300
20 MW Binary	3,690	4,100	4,500	3,400	3,830	4,240	3,270	3,730	4,170
50 MW Flash	2,260	2,510	2,750	2,090	2,350	2,600	2,010	2,290	2,560

Table A5.7 shows projected ranges in levelized generating cost given the capital cost ranges presented in Table A5.6, and the O&M costs presented in Table A5.4.

Table A5.7: Geothermal Power Plant Projected Generating Costs (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
200 kW Binary	14.2	15.6	16.9	13.0	14.5	15.9	12.5	14.2	15.7
20 MW Binary	6.2	6.7	7.3	5.8	6.4	6.9	5.7	6.3	6.8
50 MW Flash	3.9	4.3	4.6	3.7	4.1	4.4	3.6	4.0	4.4

Annex 6

Biomass Gasifier Power Systems

Biomass gasification is the process through which solid biomass material is subjected to partial combustion in the presence of a limited supply of air. The ultimate product is a combustible gas mixture known as "producer gas." The combustion of biomass takes place in a closed vessel, normally cylindrical in shape, called a "gasifier." Producer gas typically contains N (50-54 percent), CO_2 (9-11 percent), CH_4 (2-3 percent), CO (20-22 percent) and H (12-15 percent). Producer gas has relatively low thermal value, ranging from 1,000-1,100 kcal/m^3 (5,500-MJ/m^3) depending upon the type of biomass used.

Gasification of biomass takes place in four distinct stages: drying, pyrolysis, oxidation/combustion and reduction. Biomass is fed at the top of the hopper. As the gasifier is ignited in the oxidation zone, the combustion takes place and the temperature rises (900-1,200°C). As the dried biomass moves down, it is subjected to strong heating (200-600°C) in the pyrolysis zone. The biomass starts losing the volatiles at above 200°C and, continues until it reaches the oxidation zone. Once the temperature reaches 400°C, the structure of wood or other organic solids breaks down due to exothermic reactions, and water vapor, methanol, acetic acid and tars are evolved. This process is called pyrolysis. These products of pyrolysis are drawn toward the oxidation zone, where a calculated quantity of air is supplied and the combustion (similar to normal stove/furnace) takes place. A portion of pyrolysis gases and char burns here which raises the temperature to 900-1,200°C in the oxidation zone. Partial oxidation of biomass by gasifying agents (air or O_2) takes place in the oxidation zone producing high temperature gases (CO_2), also containing products of combustion, cracked and uncracked pyrolysis products, and water vapor (steam) which pass through the reduction zone consisting of a packed bed of charcoal. This charcoal is initially supplied from external sources, and, later, the char produced in the pyrolysis zone is simultaneously supplied. The reactions in the reduction zone are endothermic and temperature sensitive (600-900°C). The principal chemical reactions taking place in a gasifier are shown in Table A6.1.

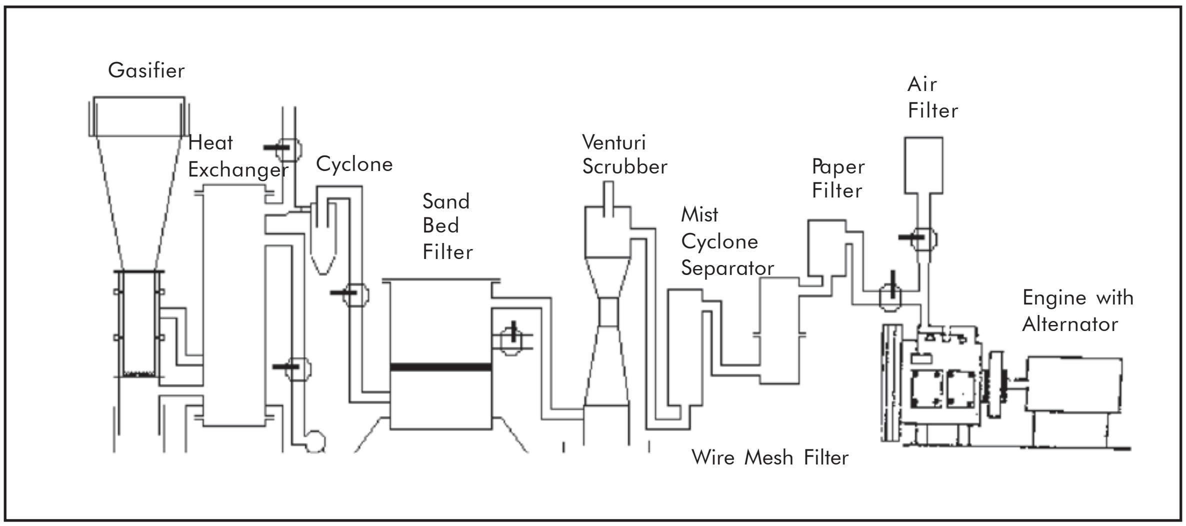
Table A6.1: Principle Chemical Reactions in a Gasifier Plant

Reaction-type	*Reaction*	*Enthalpy (kJ/mol)*
Devolatilization	C+Heat = CH_4 + Condensable Hydrocarbons + Char	
Steam-carbon	C+H_2O + Heat = CO+H_2	131.4
Reverse Boudouard	C + CO_2 + Heat = 2CO	172.6
Oxidation	C + O_2 = Heat	-393.8
Hydro Gasification	C+ 2H_2 = CH_4 + Heat	-74.9
Water Gas Shift	H_2O + CO = H_2 + CO_2 + Heat	-41.2
Methanation	3H_2 + CO = CH_4 + H_2O + Heat 4 H_2 + CO_2 = CH_4 + 2H_2O + Heat	-206.3 -165.1

In the above reactions, devolatilization takes place in the pyrolysis zone, oxidation in the oxidation zone and all other reactions in the reduction zone. The low thermal value (about 10-15 percent of natural gas) of producer gas is mainly due to diluting effect of nitrogen (N) present in the combustion air. Since N is inert, it passes through the gasifier without entering into any major chemical reactions. An efficient gasifier produces a clean gas over a range of flow rates of gas. If all the above-mentioned processes take place efficiently, the energy content of the producer gas would contain about 70-78 percent of the energy content of the biomass entering the gasifier.

The gasification process is influenced by two parameters – properties of the biomass and the gasifier design. Biomass properties such as energy content, density, moisture content, volatile matter, fixed carbon, ash content and also size and geometry of biomass affect the gasification process. The design of the oxidation zone is the most important, as the completion of each reaction depends on the residence time of biomass in the oxidation and reduction zones. Figure A6.1 shows the schematic of a gasifier-based power generation system.

Figure A6.1: Biomass Gasifier Power System Schematic



Source: DOE/EPRI.

Biomass Gasifier Technology Assessment

There are three main types of gasifiers – down draft, updraft and cross draft. In the case of down draft gasifiers, the flow of gases and solids occurs through a descending packed bed. The gases produced here contain the least amount of tar and PM. Downdraft gasification is fairly simple, reliable and proven for certain fuels. In case of updraft gasifiers, the gases and solids have counter-current flow and the product gas contains a high level of tar and organic condensable. In the cross draft gasifier, solid fuel moves down and the airflow moves horizontally. This has an advantage in traction applications. But the product gas is, however, high in tars and requires cleaning.

Other kinds of gasification technology include fluidized bed gasifiers and pyrolyzers. In a fluidized bed gasifier, the air is blown through a bed of solid particles at a sufficient velocity to keep them in a state of suspension. The bed is initially heated up and then the feedstock is introduced at the bottom of the reactor when the temperature of the reactor is quite high. The fuel material gets mixed up with the bed material and until its temperature is equal to the bed temperature. At this point the fuel undergoes fast pyrolysis reactions and evolves the desired gaseous products. Ash particles along with the gas stream are taken over the top of the gasifier and are removed from the gas stream, and the clean gas is then taken to engine for power generation.

Economic and Environmental Assessment

Table A6.2 gives details of the design and performance parameters we will assume for the economic assessment of biomass gasifier technology.

Table A6.2: Biomass Gasifier System Design Assumptions

Capacity	*100 kW*	*20 MW*
Fuel	Wood/Wood Waste/Agro Waste	Wood/Wood Waste/Agro Waste
Calorific Value of Fuel	4,000 kcal/kg	4,000 kcal/kg
Capacity Factor	80%	80%
Producer Gas Calorific Value	1,000-1,200 kcal/Nm^3	1,000-1,200 kcal/Nm^3
Life Span of System	20 Years	20 Years
Specific Fuel Consumption	1.6 kg/kWh	1.5 kg/kWh

Biomass gasifier projects are considered to be Greenhouse gases (GHG)-neutral, as there is sequestration of GHGs due to the growth of biomass feedstock – provided that the biomass used is harvested in a sustainable way. Environmental impacts associated with combustion of the biomass gas are assumed to be constrained by emissions control regulation, consistent with the World Bank standards.

Table A6.3 shows the capital costs associated with biomass gasifier-based power plants of two representative sizes – 100 kW for mini-grids and 20 MW for large-scale grid-connected applications.

Table A6.3: Biomass Gasifier Power System 2005 Capital Costs (US$/kW)

Capacity	*100 kW*	*20 MW*
Equipment Cost	2,490	1,740
Civil Cost	120	100
Engineering	70	40
Erection Cost	70	50
Process Contingency	130	100
Total Capital Cost	**2,880**	**2,030**

Fuel cost is the most important parameter in estimating the generation costs of any biomass-based power generation technology. The cost of biomass depends on many parameters, including project location, type of biomass feedstock, quantity required and present and future alternative use. Biomass fuel costs can vary widely; in this study we use a range from US$11.1/ton (US$0.64/GJ) to US$33.3/ton (US$1.98/GJ), with US$16.6/ton (US$0.99/GJ) as a probable value.

Based on the design and performance parameters given in Table A6.2, the total generating cost can be estimated inclusive of O&M costs. Table A6.4 shows the results.

Table A6.4: Biomass Gasifier Power System 2005 Generating Costs (US¢/kWh)

Capacity	*100 kW*	*20 MW*
Capital	4.39	3.09
Fixed O&M Cost	0.34	0.25
Variable Cost	1.57	1.18
Fuel Cost	2.66	2.50
Total	**8.96**	**7.02**

Future Price and Uncertainty Analysis

The future cost of these systems will likely be less than at present, as biomass gasification has considerable potential for technology improvement and economies of mass production. We assume that improvements in the areas of low tar-producing two-state gasifiers and improved cleaning and cooling equipment will yield an 8 percent reduction in capital costs by 2010 (Table A6.5).

The range over which projected biomass gasifier generation costs can vary are primarily a result of uncertainty in future cost projections plus variations in fuel costs. We carried out an uncertainty analysis to estimate the range over which the generation costs could vary due to these variable parameters and the projected generating cost bands are provided in Table A6.6.

Table A6.5: Biomass Gasifier Power System Capital Costs Projections (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Gasifier 100 kW	2,490	2,880	3,260	2,090	2,560	2,980	1,870	2,430	2,900
Gasifier 20 MW	1,760	2,030	2,300	1,480	1,810	2,100	1,320	1,710	2,040

Table A6.6: Biomass Gasifier Power Generating Costs Projections (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Gasifier 100 kW	8.2	9.0	9.7	7.6	8.5	9.4	7.3	8.3	9.5
Gasifier 20 MW	6.4	7.0	7.6	6.0	6.7	7.5	5.8	6.5	7.5

Annex 7

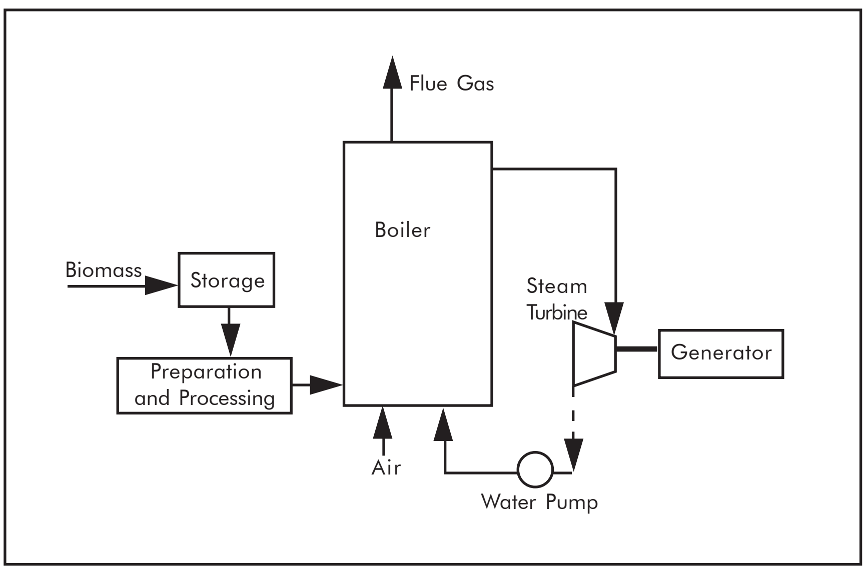
Biomass-steam Power Systems

Biomass combustion technologies convert biomass fuels into several forms of useful energy including hot air, steam or power generation. Biomass-based power generation technologies can be classified as direct firing, gasification and pyrolysis. This section will cover the direct-fired biomass combustion-based electricity generation (see Figure A7.1).

Technology Description

A pile burner combustion boiler consists of cells, each with an upper and lower combustion chamber. Biomass burns on a grate in lower chamber, releasing volatile gases which then burn in the upper chamber. Current biomass combustor designs utilize high efficiency boilers and stationary or traveling grate combustors with automatic feeders that distribute the fuel onto a grate to burn. In stationary grate design, ashes fall into a pit for collection, whereas in traveling grate type the grate moves and drops the ash into a hopper.

Figure A7.1: Biomass-steam Electric Power System Schematic



FBC are the most advanced biomass combustors. In a FBC, the biomass fuel is in a small granular form (for example, rice husk) and is mixed and burned in a hot bed of sand. Injection of air into the bed creates turbulence, which distributes and suspends the fuel while increasing the heat transfer and allowing for combustion below the temperature normally resulting in NO_x emissions. Combustors designed to handle high ash fuels and agricultural biomass residue have special features which handle slagging and fouling problems due to K, sodium (NA) and silica (SiO_2) found in agricultural residues.

Economic and Environmental Assessment

The design and performance parameters assumed for biomass-steam power projects are given in Table A7.1. Note that only one size – large, grid-connected – is assessed. Such a large power system has a high capacity factor, assuming continuous availability of the biomass feedstock, comparable to that of a conventional central station power plant.

Table A7.1: Biomass-steam Electric Power System Design Assumptions

	Biomass-steam
Capacity	50 MW
Capacity Factor (%)	80
Fuel	Wood/Wood Waste/Agro Waste
Calorific Value of Fuel	4,000 kcal/kg
Specific Fuel Consumption	1.5 kg/kWh
Life Span (year)	20
Gross Generated Electricity (GWh/year)	350

The biomass steam projects are considered to be GHG-neutral, as there is sequestration of CO_2 due to the biomass cultivation, provided that the biomass used is harvested in a sustainable way.

Table A7.2 gives the capital cost breakdown for a biomass steam power plant.

Table A7.2: Biomass-steam Electric Power Plant 2005 Capital Costs (US$/kW)

Items	*Cost*
Equipment	1,290
Civil	170
Engineering	90
Erection	70
Process Contingency	80
Total	**1,700**

Based on the capacity factor and the life of the plant, the capital cost is annualized and the generating cost is estimated in Table A7.3.

Table A7.3: Biomass-steam Electric Power Plant 2005 Generating Costs (US¢/kWh)

Capital	*2.59*
Fixed O&M	0.45
Variable O&M	0.41
Fuel	2.50
Total	**5.95**

Future Cost Projections and Uncertainty Analysis

The future costs for biomass-steam generation projects are expected to drop as a result of increased market penetration and technology standardization. Cost reductions of about 10 percent by the year 2010 are expected and are reflected in Table A7.4.

Table A7.4: Biomass-steam Electric Power Plant Projected Capital Costs (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Biomass-steam 50 MW	1,500	1,700	1,910	1,310	1,550	1,770	1,240	1,520	1,780

The uncertainty analysis for generating cost was carried out using the range of present and future costs, as shown in Table A7.4. However, the key uncertainty in estimating the generation costs of any biomass-based power generation technology is the fuel cost. The cost of biomass depends on a large number of parameters including project location, type of biomass feedstock, quantity required and present and future alternative use. Biomass fuel costs can vary widely; in this study we use a range from US$11.1/ton (US$0.64/GJ) to US$33.3/ton (US$1.98/GJ), with US$16.6/ton (US$0.99/GJ) as probable value. An O&M cost variation of 20 percent was also assumed.

Based on the cost projections, the generation cost for biomass steam power plant was estimated and shown in Table A7.5. The effect of variation in different cost components in the generation cost is shown in the tornado charts in Annex 4.

Table A7.5: Biomass-steam Electric Power Projected Generating Costs (US¢/kWh)

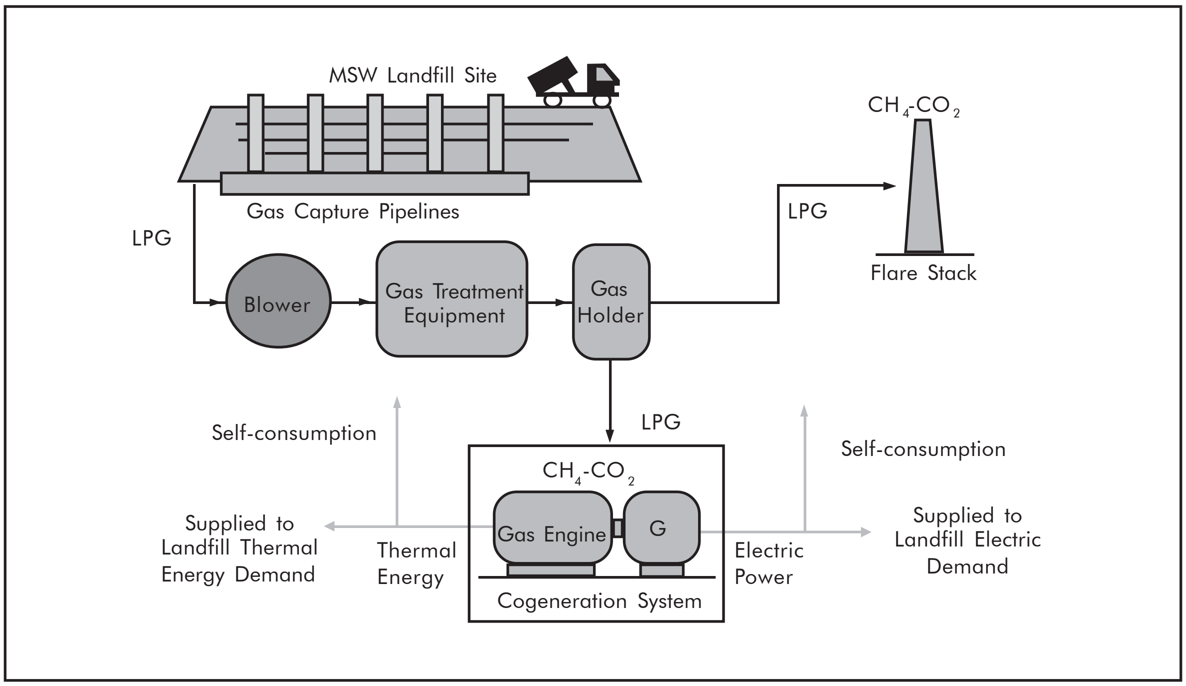
	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Biomass-steam 50 MW	5.4	6.0	6.5	5.2	5.7	6.4	5.1	5.7	6.6

Annex 8

Municipal Waste-to-power System Using Anaerobic Digestion

MSW contains significant portions of organic materials that produce a variety of gaseous products when dumped, compacted and covered in landfills. Anaerobic bacteria thrive in the oxygen(O)-free environment, resulting in the decomposition of the organic materials and the production of primarily CO_2 and CH_4. CO_2 is likely to leach out of the landfill because it is soluble in water. CH_4, on the other hand, which is less soluble in water and lighter than air, is likely to migrate out of the landfill. Landfill gas energy facilities capture CH_4 (the principal component of natural gas) and combust it for energy. Figure A8.1 shows a schematic diagram of a landfill-based municipal waste-to-energy operation.

Figure A8.1: Municipal Waste-to-power System Schematic



Source: The Ministry of Environment, Government of Japan.

Technology Description

The biogas comprises CH_4, CO_2, H and traces of H_2S. The biogas yield and the CH_4 concentration depend on the composition of the waste and the efficiency of the chemical and collection processes. The biogas produced is either used for thermal applications, such replacing fossil fuels in a boiler, or as a replacement for liquefied petroleum gas (LPG) for cooking. The biogas after treatment can also be used in gas engines to generate electric power.

Environmental and Economic Assessment

We assume the design and performance parameters listed in Table A8.1 in the economic assessment.

Table A8.1: Municipal Waste-to-power System Design Assumptions

Capacity	*5 MW*
Capacity Factor (%)	80
Fuel-type	Municipal Solid Waste
Life Span (year)	20
Gross Generated Electricity (GWh/year)	35

Since the gas (mainly CH_4) derived from the waste is used for power generation, the emissions will be below the prescribed standards. Waste-to-energy projects result in net GHG emission reductions, since CH_4 emissions that might otherwise emanate from landfill sites are avoided.

Table A8.2 gives the capital cost breakdown for a typical MSW plant of indeterminate size.

Table A8.2: Municipal Waste-to-power System 2005 Capital Costs (US$/kW)

Items	*Cost*
Equipment	1,500
Civil	900
Engineering	90
Erection	600
Contingency	160
Total	**3,250**

Using the assumed capacity factor and plant life span, we annualized the capital cost and add O&M costs to produce the estimate of generating cost shown in Table A8.3. Note that there is no fuel cost, as we assume the feedstock MSW will be provided free of charge. However, provision for royalties to an assumed municipal corporation from the sale of electricity and manure is included under variable costs.

Table A.8.3: Municipal Waste-to-power System 2005 Generating Costs (US¢/kWh)

Capital	*4.95*
Fix O&M	0.11
Variable O&M	0.43
Fuel	1.00
Total	**6.49**

Future Cost Projections and Uncertainty Analysis

There will be a decrease in future of the capital cost as well as generating costs of waste-to-power systems. We assume these trends will result in a decrease in equipment cost of 15 percent by 2015.

The uncertainty analysis for the generation cost was carried out using the range of expected capital and O&M, as shown in Table A8.4.

Table A8.4: Municipal Waste-to-power System Projected Capital Costs (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
MSW	2,960	3,250	3,540	2,660	2,980	3,270	2,480	2,830	3,130

Based on the capital cost projections, the generating cost for MSW plant was estimated and shown in Table A8.5. The effect of uncertainty in different cost components on the generation cost is shown in the tornado charts given in Annex 4.

Table A8.5: Municipal Waste-to-power Projected Generating Costs (US¢/kWh)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
MSW	6.0	6.5	7.0	5.6	6.1	6.6	5.3	5.9	6.4

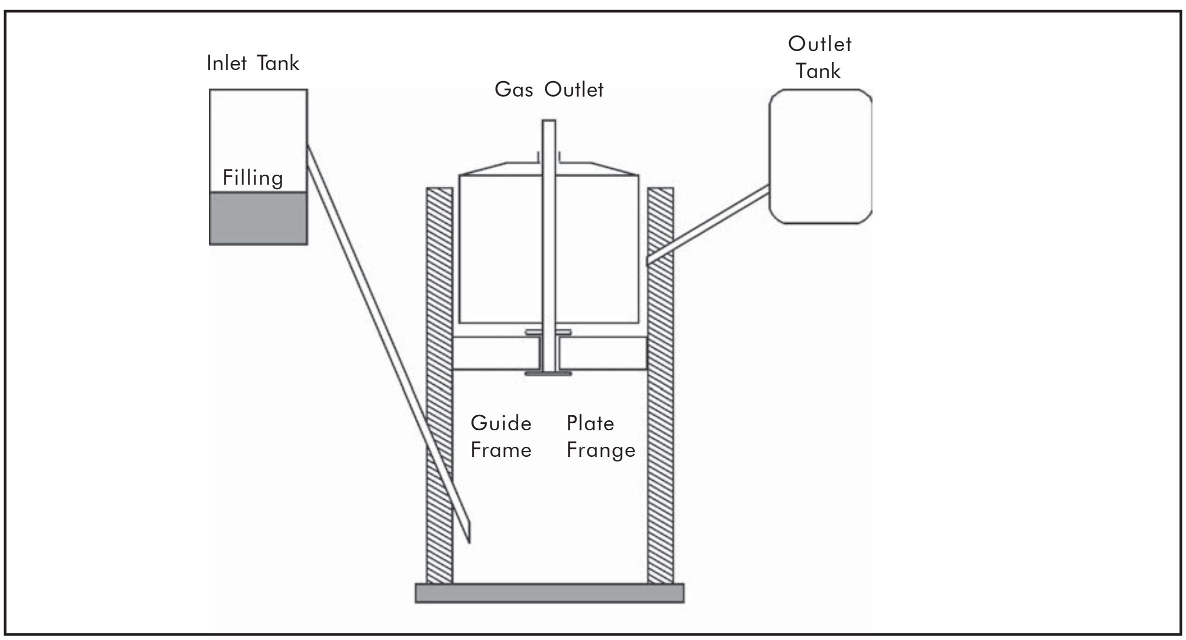
Annex 9
Biogas Power Systems

Biogas generation is a chemical process whereby organic matter is decomposed. Slurry of cow dung and other similar feedstock is retained in the biogas plant for a period of time called the hydraulic retention time (HRT) of the plant. When organic matter like animal dung, human excreta, leafy plant materials, and so on, and so forth, are digested anaerobically (in the absence of O), a highly combustible mixture of gases comprising 60 percent CH_4 and 37 percent CO_2 with traces of SO_2 and 3 percent H is produced. A batch of 25 kg of cow dung digested anaerobically for 40 days produces 1 m^3 of biogas with a calorific value of 5,125 kcal/m^3. The remaining slurry coming out of the plant is rich in manure value and useful for farming purposes.

Technology Description

Biogas plants are designed in two distinct configurations – the *floating drum*-type and the *fixed dome*-type. The floating drum plant (Figure A9.1) consists of a masonry digester and a metallic dome, which functions as a gas holder. The plant operates at a constant gas pressure throughout, that is, the gas produced is delivered at the point of use at a predetermined pressure. The gas holder acts as the lid of the digester. When gas is produced in the digester, it exerts upward pressure on the metal dome which moves up along the central guide pipe fitted in a frame, which is fixed in the masonry. Once this gas is taken out through the pipeline, the gas holder moves down and rests on a ledge constructed in the digester. Thus, a constant pressure is maintained in the system at all times. There is always sufficient slurry liquid in the annulus to act as a seal, preventing the biogas from escaping through the bottom of the gas holder.

Figure A9.1: Floating Drum Biogas Plant View



In the fixed dome plant (Figure A9.2), the digester and the gas holder (or the gas storage chamber) form part of an integrated brick masonry structure. The digester is made of a shallow well having a dome shaped roof. The inlet and outlet tanks are connected with the digester through large chutes (inlet and outlet displacement chambers). The gas pipe is fitted on the crown of the dome and there is an opening on the outer wall of the outlet displacement chamber for the discharge of spent mass (digester slurry).

The output of the biogas plant can be used for cooking or any other thermal application. For this assessment we consider the biogas plant output to be power generation.

Environmental and Economic Assessment

The design and performance assumptions for the biogas-based power generation are given in Table A9.1. We assume a biogas system sized to provide sufficient power for a 60 kW engine. We assume a capacity factor of 80 percent, which is achieved by properly sizing the plant and ensuring sufficient feedstock into the biogas system.

Figure A9.2: Fixed Dome Biogas Plant View

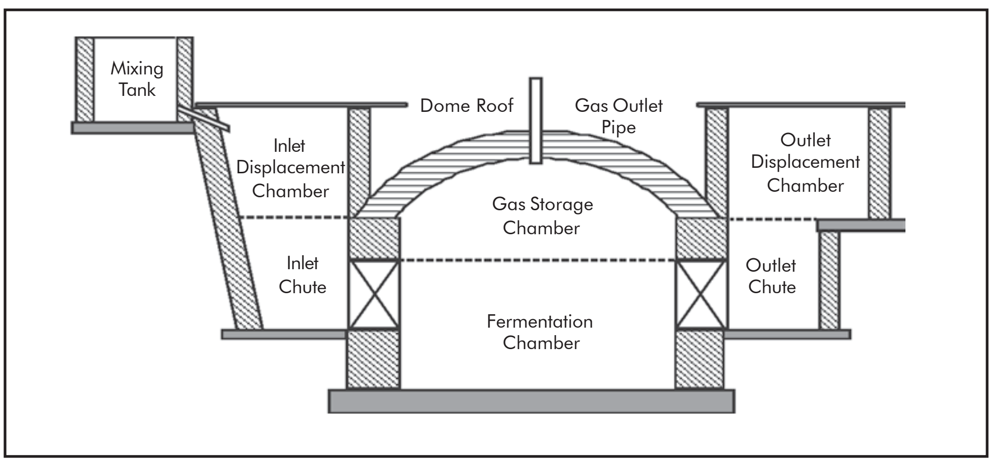


Table A9.1: Biogas Power System Design Assumptions

Capacity	*60 kW*
Capacity Factor (%)	80
Life Span (year)	20
Gross Generated Electricity	0.42 GWh

The biogas is mainly CH_4 and, thus, when combusted, will generate CO_2 emissions. However, the use of cow dung as an input means the CH_4 which would have been produced from the cow dung is replaced with CO_2, which has only a fraction of the GHG impact as the captured and combusted CH_4.

Table A9.2 shows the capital costs assumed for the biogas power generation project.

Table A9.2: Biogas Power System 2005 Capital Costs (US$/kW)

Items	*60 kW*
Equipment	1,180
Civil	690
Engineering	70
Erection	430
Contingency	120
Total	**2,490**

Table A9.3 shows the generating cost based on the capital costs of Table A9.2 and the design and performance parameters in Table A9.1.

Table A9.3: Biogas Power System 2005 Generating Costs (US¢/kWh)

Items	*60 kW*
Levelized Capital Cost	3.79
Fixed O&M Cost	0.34
Variable O&M Cost	1.54
Fuel Cost	1.10
Total	**6.77**

Future Cost Projections and Uncertainty Analysis

Biogas technology is very simple, uses local resources and has been in commercial operation for a long time.[35] Thus, it is expected that the costs would not change over time (as the capital costs projects are in 2004 US$), as shown in Table A9.4.

Table A9.4: Biogas Power System Capital Costs Projections (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Biogas 60 kW	2,260	2,490	2,790	2,080	2,330	2,570	2,000	2,280	2,540

An uncertainty analysis for future biogas power system generation cost was carried out using the range of likely variation in future costs, mainly the equipment costs and an assumed ±20 percent variation in O&M cost. The uncertainly analysis results are shown in Table A9.5.

Table A9.5: Biogas Power System Generating Costs Projections (US¢/kWh)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Biogas 60 kW	6.3	6.8	7.2	6.0	6.5	7.1	5.9	6.5	7.1

[35] *For example, the Indian biogas program started in 1973.*

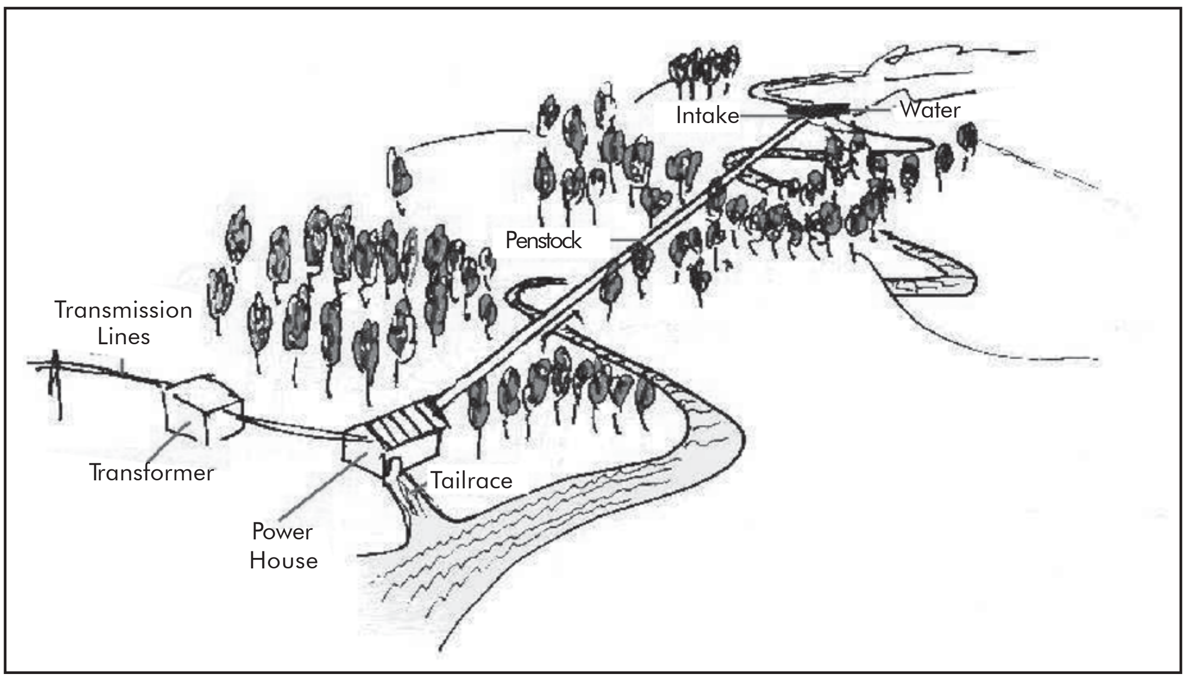
Annex 10

Micro- and Pico-hydroelectric Power Systems

Micro-hydro and pico-hydro power projects are usually RoR schemes which operate by diverting part or all of the available water flow by constructing civil works, for example, an intake weir, fore bay and penstock (note: pico-hydro units do not have a penstock). Water flows through the civil works into a turbine, which drives a generator producing electricity. The water flows back into the river through additional civil works (the tail race). The RoR schemes require no water catchments or storage, and thus have minimal environmental impacts.

The main drawback of RoR hydro projects are seasonal variation in flow, which make it difficult to balance load and power output on an annual basis. Micro- and pico-hydro systems can be built locally at low cost, and their simplicity gives rise to better long-term reliability. They can provide a source of cheap, independent and continuous power, without degrading the environment. Figure A10.1 shows a typical micro-hydro configuration.

Figure A10.1: Typical Micro-hydroelectric Power Scheme



Source: http://www.microhydropower.net/.

Technology Description

A micro-hydroelectric power project comprises two principle components: civil works and electro-mechanical equipment.

The civil works include:

- The weir, a simple construction that provides a regulated discharge to the feeder channel;
- The feeder channel, constructed of concrete with desilting tanks along its length;
- The fore bay, an open concrete or steel tank designed to maintain a balance in the power output by providing a steady design head for the project; and
- The penstock, simply a steel, concrete or PVC pipe sized to provide a steady and laminar water flow into the turbine.

The electro-mechanical works include:

- A turbine sized according to the design head and water flow available, typically a Pelton or Turgo design for high-head applications and a Kaplan or Francis design for low-head applications;
- A generator, usually a synchronous design for larger micro-hydro sites and self-excited induction design for low-power and pico-hydro applications; and
- A governor, usually an electronic load governor or electronic load controller, depending on whether the turbine and generator operate on full or varying load conditions.

A pico-hydroelectric power plant is much smaller than a micro-hydro (for example, 1 kW or 300 W), and incorporates all of the electro-mechanical elements into one portable device. A pico-hydro device is easy to install: A 300 W-class pico-hydroelectric can be installed by the purchaser because of the low (1-2 m) required waterhead, whereas, a 1 kW pico-hydroelectric requires a small amount of construction work because of the higher (5-6 m) required waterhead but provides a longer and more sturdy product life span. They are typically installed on the river or stream embankment and can be removed during flood or low flow periods. The power output is sufficient for a single house or small business. Earlier, pico-hydro devices were not equipped with any voltage or load control, which was a drawback as it produced lighting flicker and reduced appliance life. Newer pico-hydro machines come with embedded power electronics to regulate voltage and balance loads.

Economic Assessment

Table A10.1 gives the details on the design and performance assumptions used to assess micro- and pico-hydroelectric power projects. We selected three design points – a micro-hydro scheme of 100 kW and two pico-hydro schemes of 1 kW and 300 W respectively. There is a very large variation in the capacity factor depending upon the site conditions, which will be taken into account in the uncertainly analysis. In the case of off-grid and mini-grid applications demand requirements are also a limiting factor. Most of these projects work on full load, single point operation but for a limited period of time each day, so we assume an average capacity factor of 30 percent.

Table A10.1: Micro/Pico-hydroelectric Power Plant Design Assumptions

Capacity	*300 W*	*1 kW*	*100 kW*
Capacity Factor (%)	30	30	30
Source	River/Tributary	River/Tributary	River/Tributary
Life Span (year)	5	15	30
Gross Generated Electricity (kWh/year)	788.4	2,628	26,280

The cost estimations shown in Table A10.2 are drawn from numerous sources, principally Vietnam and the Philippines.

Table A10.2: Micro/Pico-hydroelectric Power Plant 2005 Capital Costs (US$/kW)

Items/Models	*300 W*	*1 kW*	*100 kW*
Equipment	1,560	1,960	1,400
Civil	–	570	810
Engineering	–	–	190
Erection	–	140	200
Total	**1,560**	**2,670**	**2,600**

Note: "–" means no cost needed.

Table A10.3 shows the generation costs for micro/pico-hydro power calculated as per the methodology described in Section 2.

Table A10.3: Micro/Pico-hydroelectric Power 2005 Generating Costs (US¢/kWh)

Items/Models	*300 W*	*1 kW*	*100 kW*
Levelized Capital Cost	14.24	12.19	9.54
Fixed O&M Cost	0.00	0.00	1.05
Variable O&M Cost	0.90	0.54	0.42
Fuel Cost	0.00	0.00	0.00
Total	**15.14**	**12.73**	**11.01**

Future Cost and Uncertainty Analysis

There has been very little variation in the equipment cost of micro- and pico-hydroelectric equipment. We, therefore, assume that the capital costs for pico/mini-hydro technology will remain constant over the study period.

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs as well as variability in the capacity factor. The capacity factor will vary widely depending upon the availability of hydro resource and the quality of the sizing and design process. We assume well-designed and well-sited schemes that would have lower capacity factor variability, 25 percent to 35 percent, with 30 percent as probable capacity factor. We allowed capital costs and O&M costs to vary across the range ±20 percent (Table A10.4).

Table A10.4: Micro/Pico-hydroelectric Power Capital Costs Projections (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	1,320	1,560	1,800	1,190	1,485	1,770	1,110	1,470	1,810
1 kW	2,360	2,680	3,000	2,190	2,575	2,950	2,090	2,550	2,990
100 kW	2,350	2,600	2,860	2,180	2,470	2,750	2,110	2,450	2,780

The generation costs estimated based on the cost projections in Table A10.4 and the design parameters in Table A10.1 are shown in Table A10.5. The sensitivity of generation cost to parametric variation in the form of tornado charts is given in Annex 4.

Table A10.5: Micro/Pico-hydroelectric Power Generating Costs Projections (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	12.4	15.1	18.4	11.4	14.5	18.0	10.8	14.3	18.2
1 kW	10.7	12.7	15.2	10.1	12.3	14.8	9.7	12.1	14.9
100 kW	9.6	11.0	12.8	9.1	10.5	12.3	8.9	10.5	12.3

Annex 11
Mini-hydroelectric Power Systems

As with micro/pico-hydro, mini-hydroelectric power schemes are usually "RoR" designs which operate by diverting the stream or river flow via civil works. A mini-hydro scheme is based on the same basic design principles and comprises the same major civil and electro-mechanical components as a micro/pico-hydro scheme. These projects do not require dams or catchments, which is preferable from an environmental point of view. Mini-hydro technology is well established around the world, and has found favor with private investors. The systems are simple enough to be built locally at low cost and have simple O&M requirements, which gives rise to better long-term reliability. These systems are highly bankable and provide a source of cheap, independent and continuous power, without degrading the environment. Larger mini-hydro projects are envisaged for grid-connected applications, while smaller mini-hydro projects are suitable for mini-grids.

Technology Description

A mini-hydroelectric power project comprises two principle components:

- Civil works; and
- Electro-mechanical equipment.

The civil works include:

- The weir, a simple construction that provides a regulated discharge to the feeder channel;
- The feeder channel, constructed of concrete with desilting tanks along its length;
- The fore bay, an open concrete or steel tank designed to maintain a balance in the power output by providing a steady design head for the project; and
- The penstock, simply a steel, concrete or PVC pipe sized to provide a steady and laminar water flow to the turbine.

The electro-mechanical works include:

- A turbine sized according to the design head and water flow available, typically a Pelton or Turgo design for high-head applications and a Kaplan or Francis design for low-head applications;
- A generator, usually a synchronous design for larger micro-hydro sites and self-excited induction design for low-power and pico-hydro applications; and
- A governor, usually an electronic load governor or electronic load controller, depending on whether the turbine and generator operate on full or varying load conditions.

Economic Assessment

We selected a representative mini-hydroelectric power plant of 5 MW for the economic assessment. Table A11.1 gives the design and performance assumptions. A properly-sited, well-designed mini-hydro project should have a capacity factor of 45 percent on average.[36]

Table A11.1: Mini-hydroelectric Power Plant Design Assumptions

Capacity	*5 MW*
Capacity Factor (%)	45
Source	River/Tributary
Auxiliary Power Ratio (%)	1
Life Span (year)	30
Gross Generated Electricity (GWh/year)	19.71

The capital cost of mini-hydro projects is very site-specific, and can range between US$1,400/kW and US$2,200/kW. The probable capital cost is US$1,800/kW. Table A11.2 shows a breakdown of the probable capital cost for a 5 MW mini-hydro power project.

Table A11.2: Mini-hydroelectric Power Plant 2005 Capital Costs (US$/kW)

Capacity	*5 MW*
Equipment	990
Civil	1,010
Engineering	200
Erection	170
Total	**2,370**

Following the methodology described in Section 2, we can estimate the generation costs on a levelized basis (Table A11.3).

[36] Based on several sources: (i) inputs from Alternate Hydro Energy Centre (AHEC), Roorkee; (ii) Small Hydro Power: China's Practice – Prof Tong Jiandong, Director General, IN-SHP; and (iii) Blue AGE Report, 2004 – A strategic study for the development of Small Hydro Power in the European Union, published by European ESHA.

Table A11.3: Mini-hydroelectric Power Plant 2005 Generating Costs (US¢/kWh)

Items/Models	*5 MW*
Levelized Capital Cost	5.86
Fixed O&M Cost	0.74
Variable O&M Cost	0.35
Fuel Cost	0.00
Total	**6.95**

Future Cost and Uncertainty Analysis

The actual equipment cost of the technologies described above has not changed over the past five years; therefore, we assume mini-hydro equipment costs will remain constant over the study period.

An uncertainty analysis was carried out to estimate the range over which the generation cost could vary as a result of uncertainty in costs as well as variations in capacity factor. The capacity factor would vary depending upon the availability of hydro resource and reliability of the electro-mechanical works. Depending upon the location, the capacity factor for mini-hydro plants vary in the range from 35 percent to 55 percent, with 45 percent as probable capacity factor. Assuming a ±10-15 percent variation in projected capital costs (Table A11.4) range together with O&M costs varied ±20 percent we can carry out our uncertainty analysis, the results of which are shown in Table A11.5.

Table A11.4: Mini-hydroelectric Power Plant Capital Costs Projections (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
5 MW	2,140	2,370	2,600	2,030	2,280	2,520	1,970	2,250	2,520

Table A11.5: Mini-hydroelectric Power Generating Costs Projections (US¢/kWh)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
5 MW	5.9	6.9	8.3	5.7	6.7	8.1	5.6	6.6	8.0

Annex 12

Large-hydroelectric Power and Pumped Storage Systems

Unlike mini-, micro-, and pico-hydro schemes, large hydroelectric projects typically include dams and catchments for water storage in order to assure a very high capacity factor consistent with the very high construction costs of these facilities. The characteristics and costs of large hydroelectric power plants are greatly influenced by natural site conditions.

Technology Description

The distinguishing characteristic of large hydroelectric and large pumped storage projects is the dam design, which generally falls into three categories – gravity concrete dams, fill dams and arch concrete dams:

- In a gravity concrete dam, the structure supports external force using the weight of concrete. Structurally this is a simple system with broad applicability to topographic conditions and excellent earthquake resistance;
- A fill dam consists of accumulated rock and soil as the main structural material. It can be built on sites where the foundation is poor, and can accommodate flexibility in design depending on the soil and stone materials available; and
- An arch-type concrete dam utilizes the geometric form of the dam to economize on the amount on concrete required. It is generally restricted to narrow valleys.

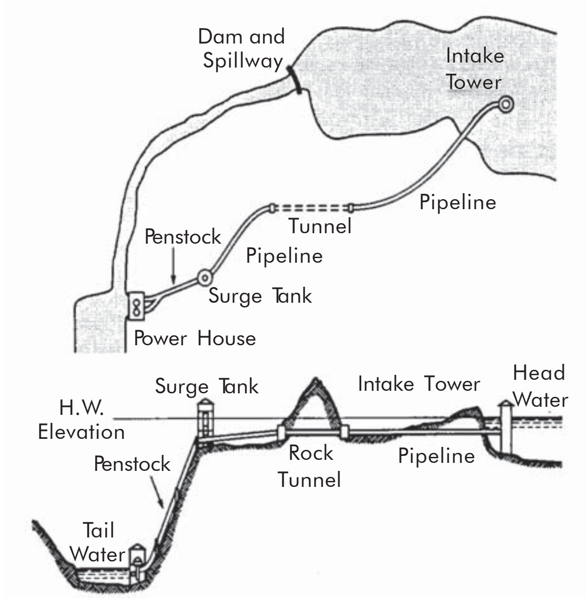
The intake system determines the amount of pressure head and the way in which water flows to the hydroelectric turbines. There are two types of intake systems, dam-type and dam-conduit type:

- A dam-type intake system obtains its head by the rise in the reservoir water surface level. The hydroelectric power plants are installed directly under the dam, which allows effective use of water and no need for a feed channel; and
- A dam-conduit type stores the water in a high dam and water is introduced to the hydroelectric power plant via a feed channel (Figure A12.1).

There are three types of power generation systems – reservoir, pondage and pumped storage:

- The reservoir power generation system employs a reservoir such as an artificial dam or a natural lake. The water storage provided by the reservoir allows water level adjustment in accordance with seasonal flux in water inflow and power output;
- A pondage-type power generation system uses a regulating pond capable of adjusting for daily or weekly flux; and
- A pumped storage power generation scheme is a specialized scheme in which several power plants are used to optimize the power output in accordance with diurnal variation in system load. In this scheme the hydroelectric power plant acts both as a generator and a pump, allowing water in a lower reservoir to be pumped up to the upper reservoir during the low-load overnight period, and then generating electricity during peak load periods.

Figure A12.1: Conduit-type Intake System for a Large Hydroelectric Power Plant



Economic Assessment

We will assess two cases – a 100 MW conventional hydroelectric facility and a 150 MW pumped storage hydroelectric facility. Design characteristics and performance parameters for the two cases are shown in Table A12.1.

Table A12.1: Large-hydroelectric Power Plant Design Assumptions

Items	*Conventional Large-hydroelectric*	*Pumped Storage Hydroelectric*
Capacity	100 MW	150 MW
Capacity Factor	50%	10%
Dam-type	Gravity Concrete	Gravity Concrete
Turbine-type	Francis	Francis Reversible Pump Turbine
Power Generation System	Pondage	Pumped Storage
Auxiliary Power Ratio[37]	0.3%	1.3%
Life Span (year)	40	40

[37] *Auxiliary power electricity in a hydro power plant is used for drainage system, cooling system, hydraulic system, switchboard system, motors, air-conditioning, lighting and so on, and so forth. Auxiliary power electricity ratio (= auxiliary power electricity/generating electricity) of the electric power used for these is an average of 0.5 percent or less in large hydro-type.*

The capital cost of hydroelectric power plants comprises civil costs (dam, reservoir, channel, power plant house, and so on, and so forth), electric costs (water turbine, generator, substation, and so on, and so forth), and other. The capital costs of large hydro power plants is dominated by the civil works. Table A12.2 shows the estimated capital costs for the two large hydroelectric power cases assessed here.

Table A12.2: Large-hydroelectric Power Plant 2005 Capital Costs (US$/kW)

Items	*Large-hydro*	*Pumped Storage Hydro*
Equipment	560	810
Civil	1,180	1,760
Engineering	200	300
Erection	200	300
Total	**2,140**	**3,170**

The generating cost of a hydro power plant (Table A12.3) is calculated by levelizing the capital costs and adding additional O&M components, per the method described in Section 2. The costs of large hydroelectric power plants are not expected to decrease in future, and are assumed constant over the study life as shown in Table A12.4.

Table A12.3: Large-hydroelectric Power Plant 2005 Generating Costs (US¢/kWh)

Items	*Large-hydro*	*Pumped Storage Hydro*
Levelized Capital Cost	4.56	34.08
Fixed O&M Cost	0.50	0.32
Variable O&M Cost	0.32	0.33
Total	**5.38**	**34.73**

Table A12.4: Large-hydroelectric Power Plant Capital Costs Projections (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Large-hydro	1,930	2,140	2,350	1,860	2,080	2,290	1,830	2,060	2,280
Pumped Storage Hydro	2,860	3,170	3,480	2,760	3,080	3,400	2,710	3,050	3,380

Uncertainty Analysis

An uncertainty analysis was carried out assuming that all cost data as well as capacity factor is variable within a ±20 percent range.[38] The analysis results are shown in Table A12.5 below.

Table A12.5: Large-hydroelectric Power Generating Costs Projections (US¢/kWh)

	2005			2010			2015		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Large-hydro	4.6	5.4	6.3	4.5	5.2	6.2	4.5	5.2	6.2
Pumped Storage Hydro	31.4	34.7	38.1	30.3	33.8	37.2	29.9	33.4	36.9

Environmental Impact

Environmental preservation is a key element in developing a hydro power plant and often dictates many details of construction and operation. It is necessary to investigate, predict and evaluate the potential environmental impact, both during construction and operation, and to take sufficient safeguard measures to prevent adverse environmental and social impacts including sediment transport and erosion, relocation of populations, impact on rare and endangered species, loss of livelihood and passage of migratory fish species in hydro power plant.

[38] *Except civil costs, which are allowed to vary ±30 percent, and the capacity factor of large-hydro, which is constrained to only vary ±10 percent.*

Annex 13

Diesel/Gasoline Engine-generator Power Systems

Diesel and gasoline engines (both characterized as internal combustion [IC] engines) can accommodate power generation needs over a wide size range, from several hundred watts to 20 MW. Features including low initial cost, modularity, ease of installation and reliability have led to their extensive use in both industrial and developing countries. A typical configuration is an engine/generator set, where gasoline and diesel engines basically indistinguishable from their counterparts in transportation vehicles are deployed in a stationary application. However, in many developing countries, slower speed diesel engines burning heavier and more polluting oils (for example, residual oil or mazout) are used.

Technology Description

A gasoline engine generator is lightweight, portable and easy to install and operate – all important characteristics for off-grid electrification. However, as shown in Table A13.1, it is not as efficient as a diesel generator, and the fuel costs are somewhat higher. A diesel generator includes the core of the diesel engine (prime mover), a generator and some auxiliary equipment, such as fuel-feed equipment, air intake and exhaust equipment, cooling equipment, lubricating equipment and starting equipment (Figure A13.1).

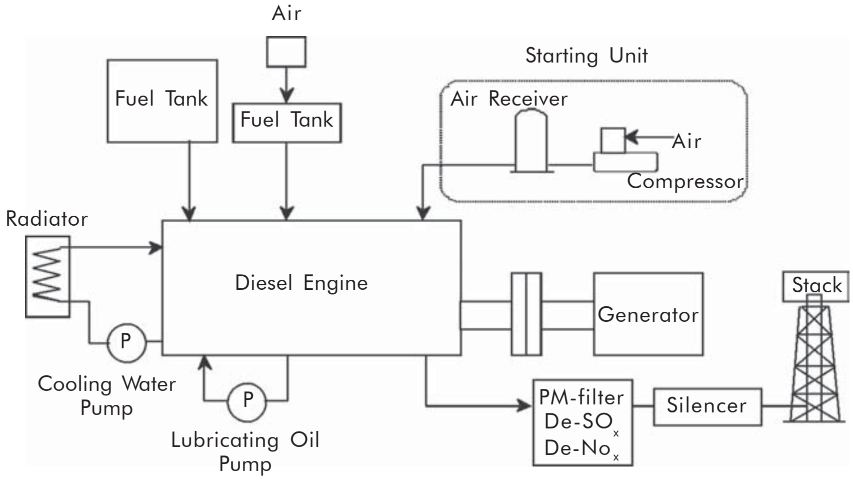
A diesel generator has an efficiency of 35-45 percent, and can use a range of low-cost fuels, including light oil, heavy oil, residual oil and even palm or coconut oil, in addition to diesel. However, since the diesel equipment is heavier than a gasoline engine generator, it is mostly deployed in stationary applications. A diesel engine also has a wide capacity range, from 2 kW to 20 MW.

Table A13.1: Characteristics of Gasoline and Diesel Generators

	Gasoline Generator	*Diesel Generator*
Thermal Efficiency (% LHV)	<27	30-45
Generating Capacity	<5 kW	2 kW-20,000 kW
Fuel-type	Gasoline	Light Oil, Fuel – A, B, C Residual Oil

In this section, we will consider four typical size diesel engines (300 W, 1 kW, 100 kW and 5 MW), which has seen a great number of installations for rural electrification in many countries including the Philippines and Indonesia.

Figure A13.1: Diesel-electric Power Plant Schematic



Environmental and Economic Assessment

We have chosen four "typical diesel plants" to assess their economic effectiveness: a 300 W and a 1 kW gasoline engine generator, and a 100 kW and a 5 MW diesel engine generator. The type of engine and fuel reflect available commercial products. The design and operating parameters for each case are shown in Table A13.2.

Table A13.2: Gasoline and Diesel Power System Design Assumptions

	300 W (Off-grid)	*1 kW (Off-grid)*	*100 kW (Mini-grid)*	*5 MW (Grid)*
Capacity Factor (%)	30	30	80	80/10
Engine-type	Gasoline	Gasoline	Diesel	Diesel
Fuel-type	Gasoline	Gasoline	Light Oil	Residual Oil
Thermal Efficiency (LHV, %)	13	16	38	43
Life Span (year)	10	10	20	20
Generated Electricity (GWh/year)	0.0008	0.003	0.7	35.0/4.4

As Table A13.2 indicates, the smaller engines are assigned a capacity factor of 30 percent. The larger engines are assigned a capacity factor of 80 percent, based on 14 hours/day of 100 percent rated output and 10 hours/day of 50 percent rated output. The 5 MW diesel plants are also considered as peaking (with 10 percent capacity factor) in grid-connected applications.

Small-sized gasoline generators are assumed to have a 10-year life span reflecting frequent start-up/shut-downs, as well as the low maintenance common in most applications. The larger diesel units are assigned an operating life of 20 years.

Emissions from IC engines are shown in Table A13.3 assuming fuel properties typically used in India. Emission control equipment costs are included in the capital cost for the two diesel generator cases.

Table A13.3: Air Emission Characteristics of Gasoline and Diesel Power Systems

	Emission Standard	*Typical Emissions*			
		Gasoline Engine		*Diesel Engine*	
		300 W	1 kW	100 kW	5 MW
PM	50 mg/Nm^3	Zero	Zero	80-120	100-200
SO_x	2,000 mg/Nm^3 (<500 MW:0.2tpd/MW)	Very Small	Very Small	1,800-2,000	4,400-4,700
NO_x	Oil: 460	1,000-1,400[39]		1,600-2,000	
CO_2	g-CO_2/net-kWh	1,500-1,900		650	

Emissions control equipment is required (shaded cells: PM 100 kW and 5 MW; SO_x 5 MW; NO_x diesel engine)

Table A13.4 shows the capital cost[40] of gasoline and diesel engine generators. Note that 300 W and 1 kW engines are portable, so only the equipment cost is included.

Table A13.4: Gasoline and Diesel Power System 2005 Capital Costs (US$/kW)

Items	*300 W*	*1 kW*	*100 kW*	*5 MW*
Equipment	890	680	600	510
Civil	–	–	10	30
Engineering	–	–	10	30
Erection	–	–	20	30
Total	**890**	**680s**	**640**	**600**

Note: "–" means no cost needed.

[39] *The two smallest gasoline engine generators emit NO_x beyond the World Bank's standard. However, since it is not realistic to add removal equipment to these small generators in order to follow a guideline strictly, cost for De-NO_x equipment is not included.*

[40] *The follow-up study on the effective use of captive power in Java-Bali Region, Japan International Cooperation Agency (JICA), November 2004.*

Table A13.5 shows the levelized generating costs, in line with the methodology described in Chapter 2. No fixed O&M cost is included for the small, portable gasoline engines.

Table A13.5: Gasoline and Diesel Power System 2005 Generating Costs (US¢/kWh)

Items	*300 W*	*1 kW*	*100 kW*	*5 MW*	
	CF=30%	*CF=30%*	*CF=80%*	*CF=80%*	*CF=10%*
Levelized Capital Cost	5.01	3.83	0.98	0.91	7.31
Fixed O&M Cost	–	–	2.00	1.00	3.00
Variable O&M Cost	5.00	3.00	3.00	2.50	2.50
Fuel Cost	54.62	44.38	14.04	4.84	4.84
Total	**64.63**	**51.21**	**20.02**	**9.25**	**17.65**

Note: "–" means no cost needed.

Future Cost and Uncertainty Analysis

As is the case with all power generation options, the costs of power plants are site-specific; they also vary from country to country and from manufacturer to manufacturer. Table A13.6 and Table A13.7 provide the projected range of capital and generating costs at present, and in the future.

Table A13.6: Gasoline and Diesel Power System Projected Capital Costs (US$/kW)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	750	890	1,030	650	810	970	600	800	980
1 kW	570	680	790	500	625	750	470	620	770
100 kW	550	640	730	480	595	700	460	590	720
5 MW	520	600	680	460	555	650	440	550	660

Table A13.7: Gasoline/Diesel Power System Projected Generating Costs (US¢/kWh)

Capacity	*2005*			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 W	59.0	64.6	72.5	52.4	59.7	71.8	52.5	60.2	75.0
1 kW	46.7	51.2	57.6	41.4	47.3	57.1	41.5	47.7	59.7
100 kW	18.1	20.0	23.1	16.6	19.0	23.3	16.7	19.2	24.3
5 MW (Base)	8.3	9.3	10.8	7.6	8.7	10.8	7.6	8.8	11.3
5 MW (Peak)	16.2	17.7	19.6	15.0	16.7	19.1	14.9	16.7	19.6

Annex 14

Combustion Turbine Power Systems

Oil and Gas CT and CCGT power plants are considered together. The common element of these plants is the use of the gas turbine, most commonly burning natural gas but in some cases distillate or heavy oil. Open cycle plants utilize only a gas turbine and are used for peaking operation. CCGT power plants utilize both a gas turbine and a steam turbine, and are used for intermediate and base load operation. Depending on the size and dispatching duty, industrial (large frame) or aero-derivative gas turbines may be used. Most of the large power generation applications are industrial large frame turbines; smaller plants (less than 100 MW) use aero-derivatives. However, there is not a clear separating line between the two.

The advanced gas turbine designs available today are largely due to 50 years of development of aero-derivative jet engines for military applications and commercial aviation. Given the aircraft designer's need for engine minimum weight, maximum thrust, high reliability, long life and compactness, it follows that the cutting-edge gas turbine developments in materials, metallurgy and thermodynamic designs have occurred in the aircraft engine designs, with subsequent transfer to land and sea gas turbine applications. However, the stationary power gas turbine designers have a particular interest in larger unit sizes and higher efficiency.

The largest commonly used gas turbines are the so-called "F" class technology, with an output range of 200-300 MW, an open cycle efficiency of 34-39 percent, and a weight of several hundred tons. Generally speaking, the industrial or frame type gas turbine tend to be a larger, more rugged, slightly less efficient power source, better suited to base-load operation, particularly if arranged in a combined-cycle block on large systems. Today, the largest aero-derivative gas turbine has an output range of 40 MW, with a 40 percent simple cycle efficiency and a weight of several tons.

A CT has many features desirable for power generation, including quick start up (within 10 minutes), capacity rating modularity (1-10 MW), small physical footprint, and low capital cost. Gas turbines demand higher quality fuels (light oil or gas containing no impurities) than diesel generators, and have considerably higher O&M requirements.

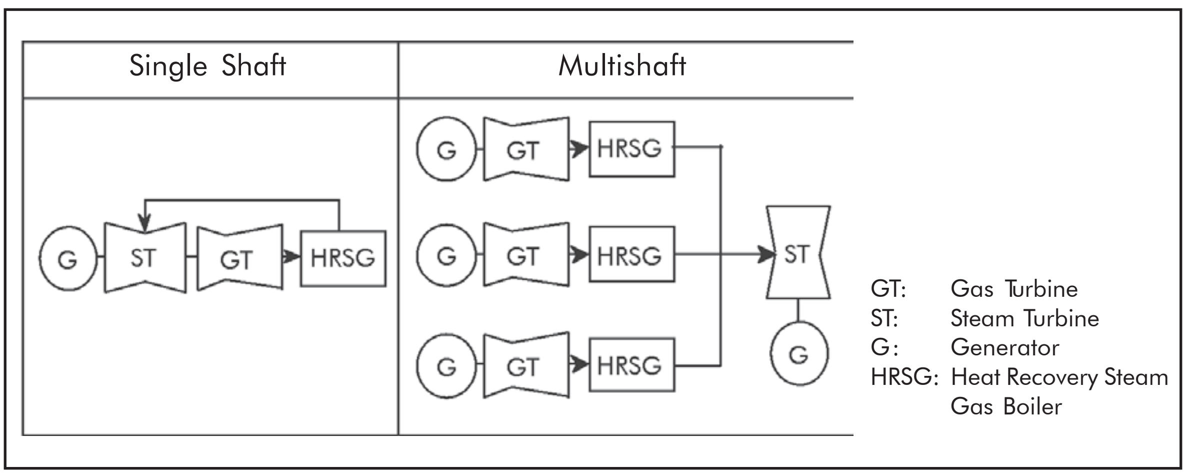
A gas turbine (or turbines) combined with a steam turbine can form a combined cycle configuration in which the overall thermal efficiency is improved by utilizing the gas turbine exhaust heat energy. The combined cycle comes in a wide variety of forms, but the study focuses on the technical and cost characteristics of a typical, newly built 300 MW CCGT power plant. Larger plants (up to 500-700 MW) are also available. The prominent feature of the system is its high efficiency, realized by combining a high temperature (1.300°C) gas turbine with two or more middle- and bottom-cycles using the 300°C and 600°C waste heat out of the combustion turbine. This approach boosts the overall thermal efficiency from 36 percent to 51 percent lower heating value (LHV). The combined cycle can be either single shaft or multishaft design, depending on the number of combustion turbines aligned with the steam turbine. The type of design is determined according to whether the power plant is designed to operate on a partial load or a base load basis.

More advanced Class "G" and "H" gas turbines have been developed and are commercially available with the combined cycle efficiency reaching up to 60 percent. However, since the operational experience is limited, these types were not considered in this study.

Technical Description

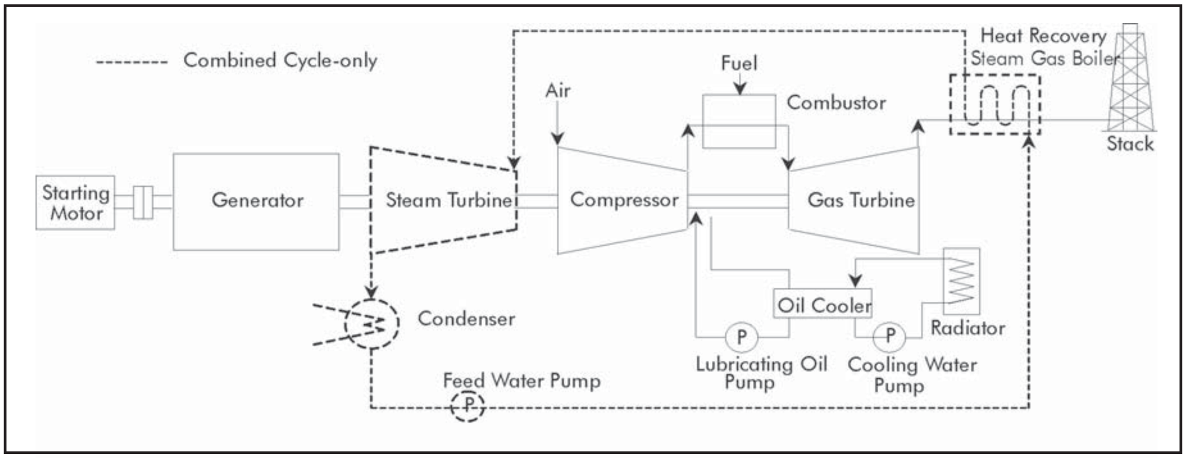
A single shaft CCGT consists of gas turbine, steam turbine and generator commonly coupled on the same shaft (Figure A14.1). In the case of multishafts (for example, 2-7 shafts) configuration, each shaft can be shut down separately, and the plant has better part-load performance. This multishaft configuration is well suited for load following, and is adopted as the basis in this report for assessing the CCGT technology.

Figure A14.1: Combined Cycle Gas Turbine Power Plant



In a multishaft combined cycle configuration, waste heat from two or more gas turbines is collected via a dedicated waste heat recovery boiler to produce steam, which turns the steam turbine generator. When the capacity of the steam turbine becomes larger, the thermal efficiency improves over its single shaft counterpart, making it a competitive candidate for base load operation. However, a multiple train single shaft configuration has an advantage of operational flexibility. The combined cycle can be constructed in phases, with only the gas turbine installations at first for basic power supply, and expanded afterwards, by adding one or more bottoming cycles to complete an integral combined cycle power plant (Figure A14.2).

Figure A14.2: Simple Cycle and Combined Cycle Gas Turbine Layouts



Environmental and Economic Assessment

Table A14.1 presents the assumed design parameters and performance characteristics used in economic assessment of CT and CCGT power systems. For the CT, we assume only a 10 percent capacity factor, reflecting a typical peak load application. For the CCGT, we assume a combination of base load operations (100 percent capacity factor for 14 hours per day) and load following (50 percent capacity factor for 10 hours per day). Because the combustion turbine is used primarily during peak times, we assume the lower cost 1,100°C turbine instead of the more efficient super-high temperature design assumed for the CCGT case. All other design parameters are derived based on typical Japanese CT and CCGT operations.

Table A14.1: CT and CCGT Power Plant Design Assumptions

	Combustion Turbine	*Combined Cycle*
Capacity	150 MW	300 MW
Capacity Factor (%)	10	80
Combustion Turbine Inlet Temperature (°C)	1,100	1,300
Steam Turbine Inlet Temperature (°C)	–	538/538/260
Fuel-type	Gas (light oil)	Gas (light oil)
Thermal Efficiency (LHV, %)	34	51
Auxiliary Power Ratio (%)	1	2
Life Span (year)	25	25
Gross Generated Electricity (GWh/year)	131	2,102
Net Generated Electricity (GWh/year)	130	2,060

Note: "–" means no cost needed.

Assuming typical fuel properties found in India originally, we can estimate the emissions of the CT and CCGT units (Table A14.2). We assume all environmental impacts are less than the World Bank guidelines and, therefore, do not include the costs for emission control equipment (such as SCR for NO_x control) in the capital costs.

Table A14.2: Air Emission Characteristics of Gas Turbine Power Plants

	Emission Standard	*Result*			
		Combustion Turbine		Combined Cycle	
		Gas	Oil	Gas	Oil
PM	50 mg/Nm^3	NA	Very Small	NA	Very Small
SO_x	2,000 mg/Nm^3 (<500 MW:0.2tpd/MW)	NA	Very Small	NA	Very Small
NO_x	Gas Turbine for Gas: 125 mg/Nm^3; Oil: 460	100-120	160-200	100-120	150-180
CO_2	g-CO_2/net-kWh	600	780	400	520

Note: NA = Not applicable.

Table A14.3 shows today's capital cost associated with oil/gas combustion turbine and combined cycle power plants.

Table A14.3: Gas Turbine Power Plant 2005 Capital Costs (US$/kW)

Items	*Combustion Turbine*	*Combined Cycle*
Equipment	370	480
Civil	45	50
Engineering	30	50
Erection	45	70
Contingency	0	0
Total	**490**	**650**

Table A14.4 shows the result of levelized generation cost calculations, using the methodology described in Annex 2.

Table A14.4: Gas Turbine Power Plant 2005 Generating Costs (US¢/kWh)

Items	*Combustion Turbine (CF=10%)*		*Combined Cycle (CF=80%)*	
	Natural Gas	*Light Oil*	*Natural Gas*	*Light Oil*
Levelized Capital Cost	5.66	←	0.95	←
Fixed O&M Cost	0.30	←	0.10	←
Variable O&M Cost	1.00	←	0.40	←
Fuel Cost	6.12	15.81	4.12	10.65
Total	**13.08**	**22.77**	**5.57**	**12.10**

Future Cost and Uncertainty Analysis

The capital costs of CT and combined cycle power plants are decreasing as a result of both mass production and technological development. In this study, we assume that capital cost decreases 7 percent from 2004 to 2015.

The uncertainty analysis assumes that all cost data varies ±20 percent. The uncertainty analysis results are shown in Table A14.5 and Table A14.6.

Table A14.5: Gas Turbine Power Plant Capital Costs Projections (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Combustion Turbine	430	490	550	360	430	490	340	420	490
Combined Cycle	570	650	720	490	580	660	450	560	650

Table A14.6: Gas Turbine Power Plant Generating Costs Projections (US¢/kWh)

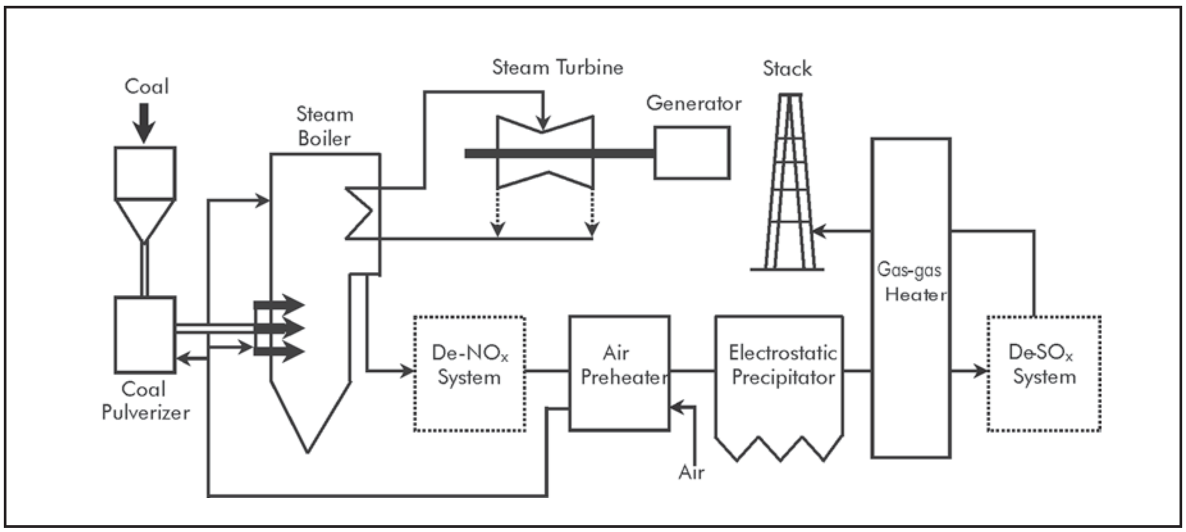
	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Combustion Turbine (gas)	11.9	13.1	14.7	10.4	11.8	14.0	10.2	11.8	14.5
Combined Cycle (gas)	4.94	5.57	6.55	4.26	5.10	6.47	4.21	5.14	6.85

Annex 15

Coal-steam Electric Power Systems

PC plant is a term used for power plants which burn PC in a boiler to produce steam that is then used to generate electricity. PC plants are widely used throughout the world, in both developed and developing countries. Figure A15.1 provides a typical schematic of such a plant equipped with post-combustion De-NO_x (selective catalytic reduction – SCR), particulate controls (electrostatic precipitator – ESP) and De-SO_x (flue gas desulfurization – FGD). SCR and FGD may not be needed depending on the coal characteristics and the environmental requirements applicable to the specific power plant site. However, more and more of the pulverized coal plants are being equipped with such environmental controls even for low-sulfur and low-NO_x producing coals. Also, the gas-to-gas heater may not be needed in all power plant sites.

Figure A15.1: Pulverized Coal-steam Electric Power Plant Schematic



Technology Description

PC plants involve:

- Grinding (pulverization) of coal;
- Combustion of coal in a boiler, producing steam at high temperature and pressure;
- Steam expansion into a turbine, which drives a generator producing electricity; and
- Treatment of combustion products (flue gas) as required before they are released into the environment through the stack (chimney).

While there are many variations in the design of the specific components of the PC plant, the overall concept is the same. Variations may include:

- Boiler design, for example, front wall-fired vs. opposed wall-fired vs. tangentially-fired vs. roof-fired, all indicating how the burners are arranged in the boiler. Other alternative arrangements include cyclones and turbo, grate, cell or wet-bottom firing methods;
- NO_x emissions control. Primary control is usually accomplished through low NO_x burners and over fire air, but, further NO_x reduction may be needed using Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) or gas reburning; and
- Control of particulates, accomplished through dry Electrostatic Precipitator (ESP), wet ESP or bag filters (baghouses).

The most important design feature of the PC plant relates to the steam conditions (pressure and temperature) entering the steam turbine. PC plants, designed to have steam conditions below the critical point of water (about 22.1 MPa-abs), are referred to as "SubCritical" PC plants, while plants designed above this critical point are referred to as "SC." Typical design conditions for SubCritical plants are: 16.7 MPa/538°C/538°C.

SC PC plants can be designed over a spectrum of operating conditions above the critical point. However, for simplification, and based on the industry experience, often the terms "SC" and "USC" are used:

- "SC" plants are designed usually at an operating pressure above the critical point (>22.1 MPa), but steam temperatures at or below 565°C. Typical design conditions are: 24.2 MPa/565°C/565°C; and

- "USC" plants are designed above these conditions.

Table A15.1 shows typical design conditions of recent SC plants operating in Europe.

Increased steam conditions are important because they increase the plant efficiency. Figure A15.2 shows how efficiency improves with higher temperatures and pressures. The relative difference in plant heat rate (inverse of efficiency) between a basic SubCritical unit with steam conditions of 16.7 MPa/538°C/538°C and a SC unit operating at 24.2 MPa/538°C/565°C is about 4 percent. If steam conditions in the SC plant can be increased to 31 MPa/600°C/600°C/600°C (note: a second reheat step has been added), the heat rate advantage over a conventional SubCritical unit reaches about 8 percent.

Further development of advanced materials is the key to even higher steam conditions and major development projects are in progress, particularly in Denmark, Germany, Japan and the United States. Plants with pressure up to 35 MPa, and steam temperatures up to 650°C (1,200°F), are foreseen in a decade, giving an efficiency approaching 50 percent.

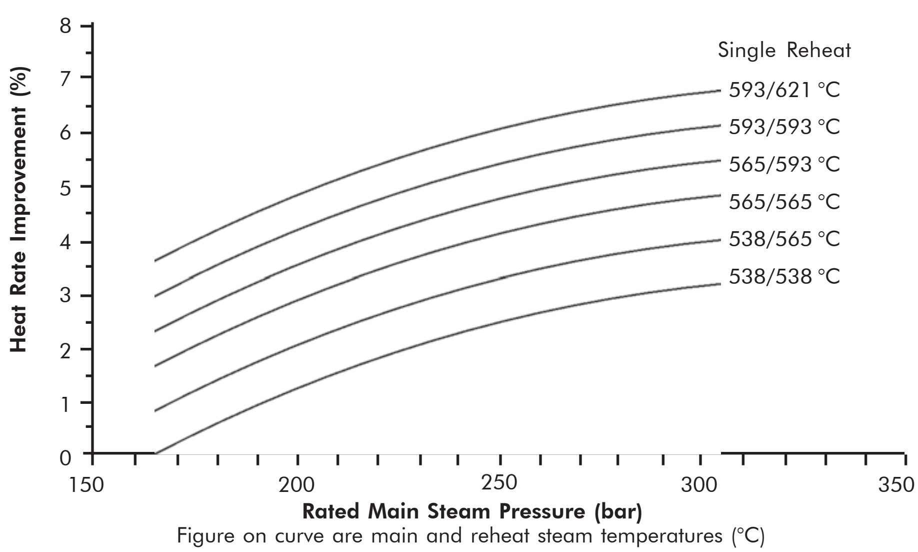
Table A15.1: European SuperCritical Pulverized Coal Power Plants

Power Plant	*Fuel*	*Output MW*	*Steam Conditions MPa/°C/°C/°C*	*Start-up Date*
Denmark:				
Skaerbaek	Coal	400	29/582/580/580	1997
Nordiyland	Coal	400	29/582/580/580	1998
Avdoere	Oil, Biomass	530	30/580/600	2000
Germany:				
Schopau A,B	Lignite	450	28.5/545/560	1995-96
Schwarze Pumpe A,B	Lignite	800	26.8/545/560	1997-98
Boxberg Q,R	Lignite	818	26.8/545/583	1999-2000
Lippendorf R,S	Lignite	900	26.8/554/583	1999-2000
Bexbach II	Coal	750	25/575/595	1999
Niederausem K	Lignite	1,000	26.5/576/599	2002

Source: The World Bank Technical Paper 011, May 2001.

This efficiency improvement represents proportional reduction of all pollutants (particulates, SO_2, NO_x, mercury [Hg] and CO_2, among others) per unit of generated electricity.

Figure A15.2: Heat Rate Improvements from SuperCritical Steam Conditions



Source: The World Bank Technical Paper 011, May 2001.

Both SubCritical and SC plants are commercially available worldwide. Subcritical plants are used in all countries; SC are less widespread, but there are more than 600 plants in operation in countries such as China, East and West European countries, India, Japan, Republic of Korea and the United States, some operating since the 70s. Individual units of over 1,000 MWe are in operation, but most new plants are in the 500-700 M We range.

Environmental and Economic Assessment

With regard to environmental performance, there are many technologies developed to reduce all "criteria pollutants" (particulates, SO_2 and NO_x) by more than 90 percent (nearly 100 percent with regard to particulates and SO_2). Some of these technologies have resulted in emission levels comparable to natural gas power plants (except for CO_2 emissions). Table A15.2 presents typical emissions for a 300 MW SubCritical steam electric power plant burning Australian coal. If lower emissions are required, there are many environmental control options to be employed to achieve them.

Table A15.2: Air Emissions from a 300 MW Pulverized Coal-steam Electric Power Plant

	Emission Standard for Coal (The World Bank, 1998)	*Result*		*Reduction Equipment*
		Boiler Exhaust	*Stack Exhaust*	
SO_x	2,000 mg/Nm^3 (<500 MW:0.2 tpd/MW)	1,700 mg/Nm^3 (33 tpd)	←	Not Required
NO_x	750 mg/Nm^3	500 mg/Nm^3	←	Not Required
PM	50 mg/Nm^3	20,000 mg/Nm^3	50 mg/Nm^3	Required
CO_2	None	880 g-CO_2/kWh	←	NA

Note: NA = Not applicable.

Table A15.3 shows design parameters and operating characteristics for typical steam-electric power plants of 300 and 500 MW size.

Table A15.3: Pulverized Coal-steam Electric Power Plant Design Assumptions

Capacity	*300 MW SubCr*	*500 MW SubCr*	*500 MW SuperCr*	*500 MW USC*
Capacity Factor (%)	80	80	80	80
Steam Turbine Inlet Pressure and Temperature	16.7 MPa/ 538/538	16.7 MPa/ 538/538	24.2 MPa/565°C/ 565°C	31 MPa/ 600°C/600°C
Fuel-type	Coal (Australia)	Coal (Australia)	Coal (Australia)	Coal (Australia)
Gross Plant Efficiency (LHV, %)	40.9	41.5	43.6	46.8
Auxiliary Power Ratio (%)	6	5	5	5
Life Span (year)	30	30	30	30
Capital Costs (US$/kW)	1,020	980	1,010	1,090

The capital costs shown in the previous Table have been developed assuming no FGD and SCR. In the absence of specific data for Tamil Nadu, India, international prices were used.[41] More specifically, the capital costs for USC are the average from the following sources after US$170/kW were taken out for FGD and SCR, which are not needed to meet the local regulations or the World Bank guidelines:

The breakdown of the capital costs is shown in Table A15.4. A clarification should be made on process contingency category. Project contingency (typically 15 percent of the capital costs) is already included in the above cost estimates. Process contingency reflects additional uncertainty with technologies which have not been used widely or with coals representative in developing countries. Five percent process contingency has been assigned to USC technology which has yet to be used in developing countries.

[41] *See: Booras, G. (EPRI) "Pulverized Coal and IGCC Plant Cost and Performance Estimates," Gasification Technologies 2004, Washington, D.C., October 3-6, 2004; Bechtel Power: "Incremental Cost of CO_2 Reduction in Power Plants," presented at the ASME Turbo Expo, 2002; Florida Municipal Power Authority: "Development of High Efficiency, Environmentally Advanced Public Power Coal-fired Generation," presented at the PowerGen International Conference, Las Vegas, Nevada, December 2003; and EPRI: "Gasification Process Selection – Trade Offs and Ironies," presented at the Gasification Technologies Conference – 2004.*

Table A15.4: Pulverized Coal-steam Electric Power Plant Capital Costs Breakdown

Equipment	*60-70%*
Civil	9-12%
Engineering	9-11%
Erection	9-12%
Process Contingency	0-10%
Total	**100%**

The generating cost estimates are shown in Table A15.5.

Table A15.5: Pulverized Coal-steam Electric Power 2005 Generating Costs (US¢/kWh)

	300 MW SubCr	*500 MW SubCr*	*500 MW SuperCr*	*500 MW USC*
Levelized Capital Cost	1.76	1.67	1.73	1.84
Fixed O&M Cost	0.38	0.38	0.38	0.38
Variable O&M Cost	0.36	0.36	0.36	0.36
Fuel Cost	1.97	1.92	1.83	1.70
Total	**4.47**	**4.33**	**4.29**	**4.29**

Future Price and Uncertainty Analysis

The total capital costs and generation costs for the options being considered are shown in Table A15.6 and Table A15.7.

Table A15.6: Pulverized Coal-steam Electric Power Capital Costs Projections (US$/kW)

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 MW SubCr	1,080	1,190	1,310	960	1,080	1,220	910	1,060	1,200
500 MW SubCr	1,030	1,140	1,250	910	1,030	1,150	870	1,010	1,140
500 MW SuperCr	1,070	1,180	1,290	950	1,070	1,200	900	1,050	1,190
500 MW USC	1,150	1,260	1,370	1,020	1,140	1,250	960	1,100	1,230

Table A15.7: Pulverized Coal-steam Electric Power Generating Costs Projections (US¢/kWh)

	2005			2010			2015		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
300 MW SubCr	4.18	4.47	4.95	3.91	4.20	4.76	3.86	4.20	4.84
500 MW SubCr	4.05	4.33	4.79	3.77	4.07	4.62	3.74	4.06	4.69
500 MW SuperCr	4.02	4.29	4.74	3.74	4.04	4.56	3.72	4.03	4.63
500 MW USC	4.02	4.29	4.71	3.74	4.02	4.51	3.69	3.99	4.55

Annex 16
Coal-IGCC Power Systems

As IGCC power plant in its simplest form is a process where coal is gasified with either O or air, and the resulting synthesis gas, consisting of H and CO, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a HRSG where it produces steam that drives a turbine. Power is produced from both the gas and steam turbine generators. By removing the emissions-forming constituents from the synthetic gas prior to combustion in the gas turbine, an IGCC power plant can meet very stringent emission standards.

There are many variations on this basic IGCC scheme, especially in the degree of integration. It is the general consensus among IGCC plant designers today that the preferred design is one in which the Air Separation Unit (ASU) derives part of its air supply from the gas turbine compressor and part from a separate air compressor.

Technology Description

Three major types of gasification systems in use today are: moving bed; fluidized bed; and entrained flow. All three systems use pressurized gasification (20 to 40 bars), which is preferable to avoid auxiliary power losses for synthetic gas compression. Most gasification processes currently in use or planned for IGCC applications are O-blown, which provides potential advantages if sequestration of CO_2 emissions is a possibility.[42]

In the coal-fueled IGCC power plant design, the hot syngas leaving the gasifier goes to a residence vessel to allow further reaction. It is then cooled in the High Temperature Heat Recovery (HTHR) section before almost all of the particulates are removed by a hot gas cyclone. The remaining particulates and water soluble impurities are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before being recycled to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

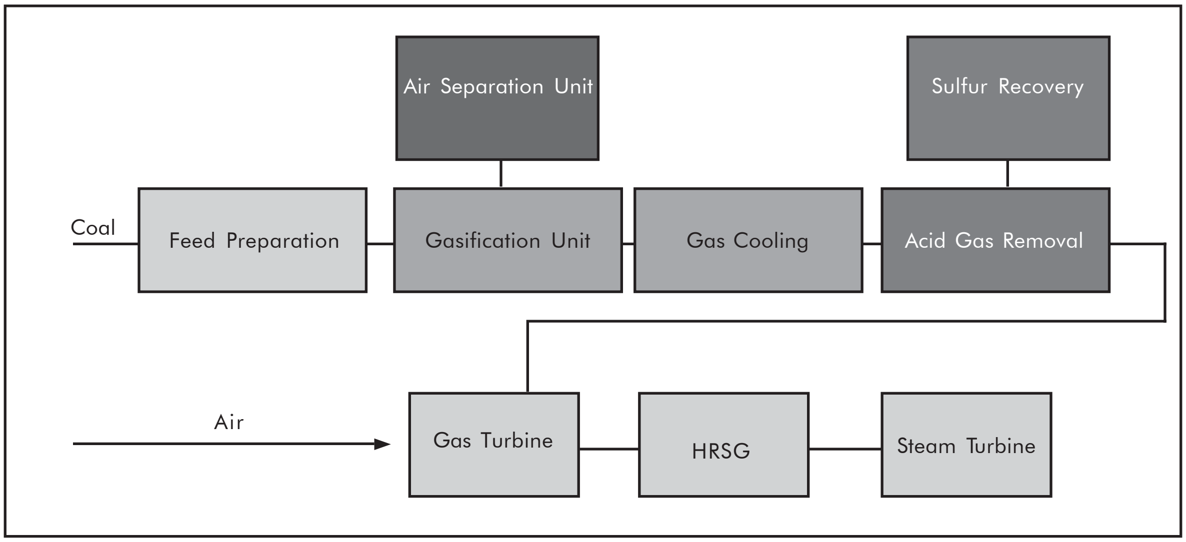
Figure A16.1 provides a typical configuration for a coal-fired IGCC power plant such as that considered in this study.

Most of the large components of an IGCC plant (such as the cryogenic cold box for the ASU, the gasifier, the syngas coolers, the gas turbine and the HRSG sections) can be shop-fabricated

[42] *See various presentations from the Gasification Technologies Council.*

and transported to a site. The construction/installation time is estimated to be about the same (three years) as for a comparably sized conventional coal power plant.

Figure A16.1: Coal-IGCC Power System Schematic



IGCC provides several environmental benefits over conventional units. Since gasification operates in a low-O environment (unlike conventional coal plants, which is O-rich for combustion), the sulfur in the fuel converts to H_2S, instead of SO_2. The H_2S can be more easily captured and removed than SO_2. Removal rates of 99 percent and higher are common using technologies proven in the petrochemical industry.

IGCC units can also be configured to operate at very low NO_x emissions without the need for Selective Catalytic Reduction (SCR). Two main techniques are used to lower the flame temperature for NO_x control in IGCC systems. One saturates the syngas with hot water while the other uses N from ASU as a diluting agent in the combustor. Application of both methods in an optimized combination has been found to provide a significant reduction in NO_x formation. NO_x emissions typically fall in the 15-20 parts per million (ppm) range, which is well below any existing emissions standard.

The basic IGCC concept was first successfully demonstrated at commercial scale at the pioneer Cool Water Project in Southern California from 1984 to 1989. There are currently two commercial sized, coal-based IGCC plants in the United States, and two in Europe. The two projects in the United States were supported initially under the DOE's Clean Coal Technology demonstration program, but are now operating commercially without DOE support.

Environmental and Economic Assessment

Table A16.1 provides the design parameters and operating characteristics assumed for the 300 MW coal-fired IGCC power plant assessed here.

Table A16.1: Coal-IGCC Power System Design Assumptions

Capacity	*300 MW*	*500 MW*
Capacity Factor (%)	80	
Life Span (year)	30	
Fuel-type	Coal (Australia)	
Gasifier-type	Coal Slurry Entrained Bed	
Oxygen Purity	95%	
Auxiliary Power Ratio (%)	11	10
Gross Thermal Efficiency (LHV, %)	47	48
Gross Generated Electricity (GWh/year)	2,102	3,504
Net Generated Electricity (GWh/year)	1,870	3,154

Assuming coal properties typical of Illinois # 6 coals, the emission characteristics of a 300 MW IGCC are shown in Table A16.2. IGCC power plants are capable of removing 99 percent of S in the fuel as elemental S; hence S emissions are extremely low. The high pressure and low temperature of combustion sharply reduces NO_x formation.

Table A16.2: The World Bank Air Emission Standards and IGCC Emissions

	Emission Standard for Coal	*IGCC Plant Emissions*
SO_x	2,000 mg/Nm^3 (<500 MW:0.2 tpd/MW)	> 0.30 gm/kWh
NO_x	750 mg/Nm^3	> 0.30 gm/kWh
PM	50 mg/Nm^3	Negligible
CO_2	None	700-750 gm/kWh

Indicative capital costs for the IGCC plant considered are as shown in Table A16.3, while conversion to levelized generation costs using the method described in Annex 2 yields the results shown in Table A16.4.

Table A16.3: Coal-IGCC Power Plant 2005 Capital Costs (US$/kW)

	300 MW	*500 MW*
Equipment & Material	1,010	940
Engineering	150	140
Civil	150	140
Construction	100	100
Process Contingency	200	180
Total Plant Cost	**1,610**	**1,500**

Table A16.4: Coal-IGCC Power Plant 2005 Generating Costs (US¢/kWh)

	300 MW	*500 MW*
Levelized Capital Cost	2.49	2.29
Fixed O&M	0.90	0.90
Variable O&M	0.21	0.21
Fuel	1.79	1.73
Total COE	**5.39**	**5.14**

Future Cost and Uncertainty Analysis

The cost of coal-based IGCC power plants probably will not change over the next five years until the first generation commercial units are commissioned. Improvements in design with respect to advanced gas turbines and hot gas clean-up systems may be expected over the next 10 years. The results of operating experience accumulated in these plants and the confidence gained in the utility industry overall may bring down the cost of these plants by about 10 percent over the next 10 years. In this assessment, we assume that all cost data is variable ±30 percent, yielding the Monte Carlo simulation analysis results shown in Table A16.5.

Table A16.5: Coal-IGCC Capital and Generating Costs Projections

		2005			*2010*			*2015*		
		Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Capital Cost (US$/kW)	300 MW	1,450	1,610	1,770	1,200	1,390	1,550	1,070	1,280	1,440
500 MW	1,350	1,500	1,650	1,130	1,300	1,450	1,000	1,190	1,340	
Generating Cost (US¢/kWh)	300 MW	5.05	5.39	5.90	4.58	4.95	5.52	4.40	4.81	5.43
	500 MW	4.81	5.14	5.62	4.38	4.74	5.28	4.21	4.60	5.19

Annex 17

Coal-fired AFBC Power Systems

AFBC is a combustion process in which limestone is injected into the combustion zone to capture the S in the coal. The $CaSO_4$ by-product formed from the combination of SO_2 and the CaO in the limestone) is captured in the particulate control devices (electrostatic precipitator or bag filter) and disposed along with the fly ash.

Technology Description

There are two types of fluidized bed designs, the bubbling AFBC and the circulating AFBC. The difference is in the velocity of the gas inside the boiler and the amount of recycled material. Bubbling AFBC has lower velocity; hence less amount of material escapes the top of the boiler. Circulating AFBC has higher velocity and much higher amount of recycled material relative to the incoming coal flow.

Bubbling AFBC is used mostly in smaller plants (10-50 MW_e) that burn biomass and municipal wastes. Circulating AFBC, also known as circulating fluidized bed (CFB), is used for utility applications, especially in plants larger than 100 MW_e. We focus on circulating AFBC in this report.

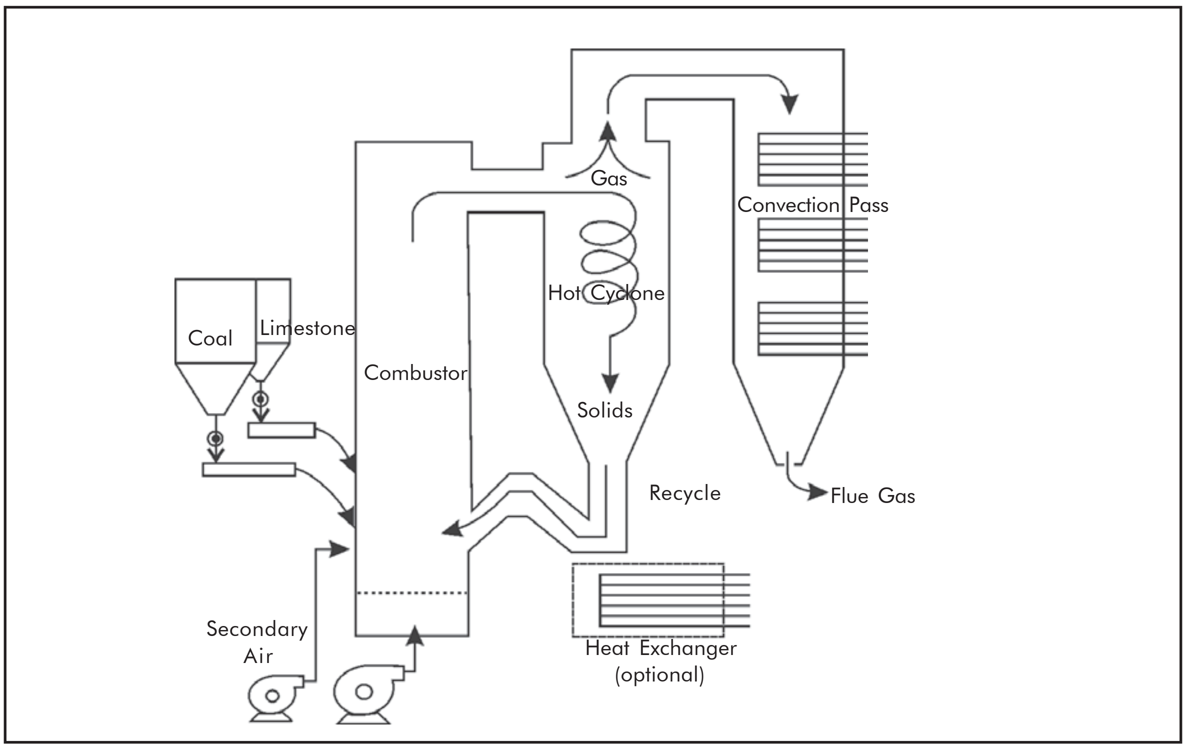
AFBC boilers (Figure A17.1) are very similar to conventional PC boilers. The majority of boiler components are similar, and hence manufacturing of the furnace and the back-pass can be done in existing manufacturing facilities. In addition, an AFBC boiler utilizes the Rankine steam cycle with steam temperatures and pressures similar to PC boilers. AFBC boilers can be designed for either SubCritical or SC conditions. Most AFBC boilers, utilized so far, are of the SubCritical type, mainly because the technology has been utilized in sizes up to 350 MW_e, where SubCritical operation is more cost-effective. As the technology is scaled up (above 400-500 MW_e), the SC design may be used depending on site-specific requirements (for example, cost of fuel and environmental requirements).

The difference of AFBC relative to PC boilers stems from lower operating temperatures and the injection of limestone in the furnace to capture SO_2 emissions. Typical maximum furnace temperature in an AFBC boiler is in the 820-870°C (1,500-1,600°F) range, while conventional PCs operate at 1,200-1,500°C (2,200-2,700°F). Low combustion temperature limits the formation of NO_X, and is also the optimum temperature range for in situ capture of SO_2.

The injected limestone is converted to lime, a portion of which reacts with SO_2 to form $CaSO_4$, a dry solid which is removed in the particulate collection equipment. A cyclone is located between the furnace and the convection pass to capture unreacted lime and limestone present in the flue gases exiting the furnace. The solids collected in the cyclone are recirculated to the furnace to improve the overall limestone utilization. Limestone injection can remove up to 90-95+ percent of S in the coal, eliminating the need for FGD downstream of the boiler. AFBCs have NO_x emissions 60-70 percent less than conventional PCs with low NO_x burners.

AFBC boilers can efficiently burn low reactivity and low-grade fuels, which may not be burned in conventional PCs. Such fuels include anthracite, coal cleaning wastes, and industrial and municipal wastes. High-ash fuels, such as lignite, are particularly suitable for AFBC technology.

Figure A17.1: AFBC Process Schematic



Source: The World Bank.[43]

Environmental and Economic Assessment

Consistent with the methodology followed in this study, and especially the assumptions made for the large power plants, AFBC power plant economics were developed for an indicative design located in India.

[43] *"The Current State of Atmospheric Fluidized-bed Combustion Technology," Washington, DC: The World Bank, Technical Paper #107, Fall 1989.*

The design assumptions are as follows:

- Gross output: 300 MW;
- SubCritical steam cycle with steam conditions: 16.7 MPa/538°C/538°C (2,400psi/1,000°F/1,000°F);
- Gross thermal efficiency: 41% (LHV);
- Auxiliary power ratio: 7%;
- Plant life: 30 years;
- CF: 80%;
- Onsite coal storage: 30 days at 100% load and utilization factor;
- Start-up fuel: oil; and
- Ash transferred through a pneumatic system to adjacent disposal pond.

The emission results for the indicative coal-fired AFBC design are compared with the World Bank's coal-fired power plant standards in Table A17.1.

Table A17.1: AFBC Emission Results and the World Bank Standards

	The World Bank Emission Standards for Coal	Emissions Calculated for a Coal-fired AFBC Design Located in India
SO_x	2000 mg/Nm^3 (<500 MW: 0.2 tpd/MW)	940 mg/Nm^3 [44]
NO_x	750 mg/Nm^3	250 mg/Nm^3 [45]
PM	50 mg/Nm^3	Under 50 mg/Nm^3 [46]
CO_2	–	940 g-CO_2/Year

Note: "–" means no cost needed.

The capital costs of an AFBC plant are affected by many site-specific factors, such as coal properties, environmental regulations, sourcing of the key components, and geophysical characteristics of the construction site. Table A17.2 provides a sample of the relevant capital costs available for various locations.

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[44] Indian coal contains CaO in the ash and can capture SO_2 without adding limestone. If the S in the coal is relatively low and/or the environmental standards are not very strict, limestone may not be required.

[45] Lower than 100 mg/Nm^3 (typically 30-50 mg/Nm^3) is possible with the addition of SNCR (Selective Non-Catalytic Reduction) system in the AFBC boiler.

[46] Depends on ESP or fabric filter design; in some developing countries higher particulates (for example, 100 or 150 mg/Nm^3) may be allowed. In this case, the capital costs may be slightly lower (for example, US$10-15/kW).

Table A17.2: Indicative AFBC Installations and Capital Costs Estimates

Location	*Size (MW)*	*Capital Costs (US$/kW)*	*Source*
Elbistan, Turkey	250	1,100	The World Bank, Turkey EER Report/ Task 2
Generic, China	300	721	The World Bank/ESMAP Paper 011[47]
Jacksonville, United States	2x300	1,050	Coal Age Magazine, November 2002
Generic, Europe	150	1,273[48]	Eurostat (Les Echos Group), 2003[49]
Generic, United States	200	1,304	Alstom (2003)[50]
Generic, United States (SuperCritical)	664	1,038	Alstom (2003)[51]
Average		**1,081**	

Based on these actual projects, we provide the breakdown of coal-fired AFBC costs shown in Table A17.3.

Table A17.3: Coal-fired AFBC Power Plant 2005 Capital Costs (US$/kW)

Items	*300 MW*	*500 MW*
Equipment	730	680
Civil	120	120
Engineering	110	110
Erection	120	110
Process Contingency	100	100
Total[52]	**1,180**	**1,120**

[47] ESMAP, "Technology Assessment of China Clean Coal Technologies: Electric Power Production," 2001.
[48] Note: The publication provides the costs in Euros; considering that US$1 was equal to €0.85 to 1.10 during 2003, we assume that US$1 equal €1.0.
[49] Source: World Energy Council, "Performance of Generating Plant 2004," Section 3.
[50] Marion, J., Bozzuto, C., Nsakala, N., Liljedahl, G., "Evaluation of Advanced Coal Combustion & Gasification Power Plants with Greenhouse Gas Emission Control," Topical Phase-I, DOE-NETL Report under Cooperative Agreement No. DE-FC26-01NT41146, prepared by Alstom Power Inc., May 15, 2003.
[51] Source: Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants," Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222, prepared by Alstom Power Inc.,
[52] Total Capital Requirement (TCR) is "overnight costs" not including interest during construction.

Typical O&M values for a coal-fired AFBC plant are provided in Table A17.4, while typical generating costs are shown in Table A17.5.

Table A17.4: Coal-fired AFBC Power Plant 2005 O&M Costs (US¢/kWh)

Items	*300 MW*	*500 MW*
Fixed O&M Cost	0.50	0.50
Variable O&M Cost	0.34	0.34
Total O&M	**0.84**	**0.84**

Table A17.5: Coal-fired AFBC Power Plant 2005 Generating Costs (US¢/kWh)

Items	*300 MW*	*500 MW*
Levelized Capital Cost	1.75	1.64
O&M Cost	0.84	0.84
Fuel Cost	1.52	1.49
Generating Cost	4.11	3.97

Technology Status and Development Trends

The technology is considered commercially available up to 350 MW, as demonstrated by hundreds of such boilers operating throughout the world (for example, Australia, China, Czech Republic, Finland, France, Germany, India, Japan, Poland, Korea, Sweden, Thailand and the United States). In 1996, EPRI estimated that there are approximately 300 AFBC units (larger than 22 tons/hr each) in operation worldwide. Since then (1996), the number of AFBC operating units has increased above 600 units. Experience from these units has confirmed performance and emissions targets, high reliability and ability to burn a variety of low quality fuels.[53]

AFBC plants are being built worldwide, and are especially well suited for solid fuels difficult to burn in a PC boiler (anthracite, lignite, brown coal and coal wastes). AFBC plants can

[53] *Palkes, M., Waryasz, R., "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants," Final DOE-NETL Report under Cooperative Agreement No. DE-FCP-01NT41222, prepared by Alstom Power Inc., February 2004.*

also utilize industrial and MSWs, petroleum coke and other combustible industrial waste as supplemental fuels. AFBC technology is expected to be used widely in the future, mainly in new power plant applications. Costs are expected to decline, especially in developing countries such as China and India. Specific capital cost reductions are envisioned through:

- Scale up of the technology to 500-600 MW level; this has a potential reduction of US$200-300/kW comparing the 500-600 MW plant to the 300 MW plant; and
- Further improvement of plant design resulting in 5 percent reduction of capital costs every five years for the nominal 300 MW plant, resulting in capital costs of: US$1,000/kW in 2010, and US$950/kW in 2015.[54]

Uncertainty Analysis

The analysis results using Monte Carlo simulation are shown in Table A17.6.

Table A17.6: Coal-fired AFBC Power Plant Projected Capital and Generating Costs

		2005			*2010*			*2015*		
		Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Capital Cost (US$/kW)	300 MW	1,060	1,180	1,300	940	1,070	1,210	880	1,040	1,180
	500 MW	1,010	1,120	1,230	900	1,020	1,140	840	990	1,120
Generating Cost (US¢/kWh)	300 MW	3.88	4.11	4.56	3.72	3.98	4.55	3.67	3.96	4.55
	500 MW	3.75	3.97	4.40	3.61	3.81	4.42	3.58	3.83	4.71

[54] *All data in June 2004 US$.*

Annex 18

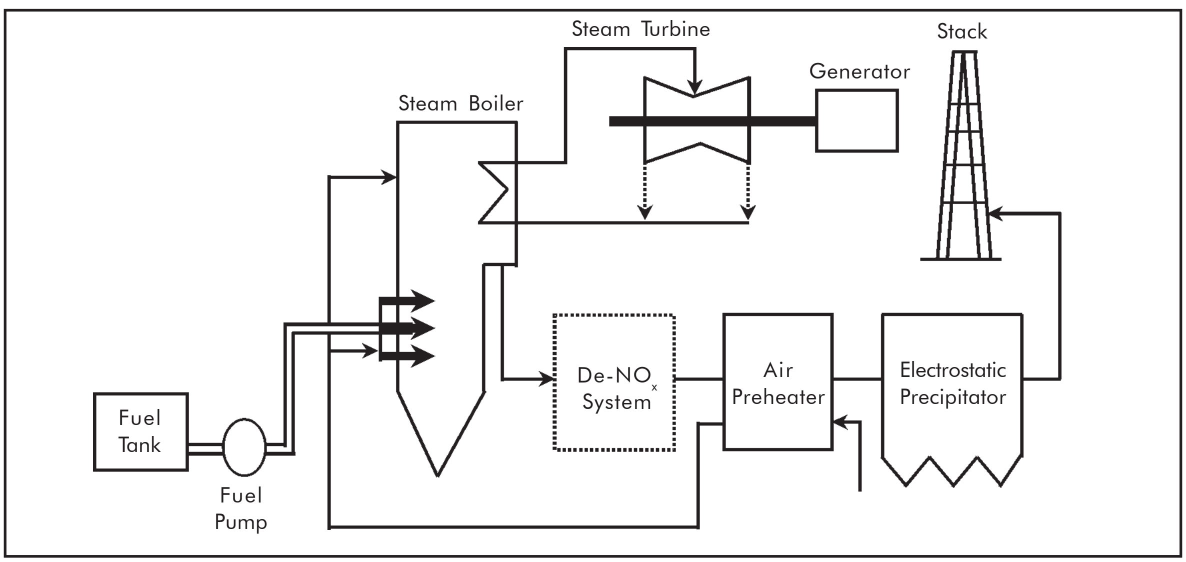
Oil-fired Steam-electric Power Systems

Oil-fired steam power plants have been used around the world for many years and they are particularly common in countries with access to cheap oil (mainly oil-producing regions such as the Middle East) and countries without access to other energy sources (for example, Italy and Japan). However, after the two oil crises of the 70s, oil is used less and less for power generation mainly due to the high prices, but also the development of new, more efficient technologies. Nevertheless, oil continues to play some role in many countries.

Technology Description

The oil-fired power plant consists of a boiler, in which the oil is burned and water is heated to superheated (high temperature and pressure) steam; the steam in turn expands in a steam turbine which turns a generator to produce electricity. A schematic of an oil-fired steam-electric power plant is shown in Figure A18.1. With the exception of the fuel being burned, the system configuration is very similar to PC power plants. As in these plants, oil-fired plants could be designed for SC or SubCritical steam conditions. SubCritical is the most common, but SC plants have been used in countries such as Italy and Japan.

Figure A18.1: Oil-fired Steam-electric Power Plant



Environmental and Economic Assessment

Typical design and operating parameters for oil-fired plants are shown in Table A18.1.

Table A18.1: Oil-fired Steam-electric Power Plant Design Assumptions

Capacity	*300 MW*
Capacity Factor (%)	80
Steam Turbine Inlet Pressure and Temperature	16.7 MPa /538/538
Fuel-type	Residual Oil
Gross Thermal Efficiency (LHV, %)	41
Auxiliary Power Ratio (%)	5
Life Span (year)	30
Gross Generated Electricity (GWh/year)	2,102
Net Generated Electricity (GWh/year)	1,997

A capacity factor of 80 percent is assumed, based on 14-hour operation at 100 percent (full load) output and 10-hour operation at 50 percent rated output per day.

Residual oil with properties typically found in India is used.[55] Emissions from a 300 MW oil-fired plant (SO_x, NO_x, PM and CO_2) are shown in Table A18.2. For the oil quality assumed, the SO_x and NO_x emissions are below the World Bank's emission standards; therefore, only ESP is included in the capital cost. However, for higher S oil, SO_2 emissions may require control either through treatment of the oil (before combustion) or through flue gas desulfurization, even though the latter is not common due to unfavorable economics. The most common is to use low-S oil. NO_x emissions could be a problem too, but in most cases properly designed burners (combustion system) could control NO_x emissions to meet the World Bank Environmental Guidelines and emission standards of most countries. For countries with very tight standards, SCR may be needed, in which case special consideration needs to be made to potential impacts from metals in the oil (especially vanadium) on the effectiveness of the SCR catalyst.

[55] *1.2% S content.*

Table A18.2: Oil-fired Steam-electric Power Plant Air Emissions

	Emission Standard for Oil	*Emissions*		*Emission Control Equipment*
		Boiler Exhaust	*Stack Exhaust*	
SO_x	2,000 mg/Nm^3 (<500 MW:0.2 tpd/MW)	1,500 mg/Nm^3 (33 tpd)	Same	Not Required
NO_x	460 mg/Nm^3	200 mg/Nm^3	Same	Not Required
PM	50 mg/Nm^3	300 mg/Nm^3	50 mg/Nm^3	Required
CO_2	None	670 g-CO_2/kWh	Same	NA

Note: NA = Not applicable.

Table A18.3 shows typical capital cost for oil-fired steam plants,[56] while Table A18.4 shows the generation costs using the methodology described in Section 2.

Table A18.3: Oil-fired Steam-electric Power Plant 2005 Capital Costs (US$/kW)

Equipment	*600*
Civil	100
Engineering	80
Erection	100
Total	**880**

Table A18.4: Oil-fired Steam-electric Power 2005 Generating Costs (US¢/kWh)

Levelized Capital Cost	*1.27*
Fixed O&M Cost	0.35
Variable O&M Cost	0.30
Fuel Cost (levelized fuel cost is as US$5.8/GJ)	5.32
Total	**7.24**

[56] *Preliminary Study on the Optimal Electric Power Development in Sumatra, Japan International Cooperation Agency (JICA), January 2003.*

Future Cost and Uncertainty Analysis

Considering the uncertainty associated with the cost estimates (mainly due to site-specific considerations) capital and generation costs may vary (Table A18.5). The same Table shows a decline in the capital costs over time, even though it is not substantial due to the fact that the technology is mature, and is not expected to develop further.

Table A18.5: Oil-fired Steam-electric Power Plant Projected Capital and Generating Costs

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Capital Cost (US$/kW)	780	880980	700	810	920	670	800	920	
Generating Cost (US¢/kWh)	6.21	7.249.00	5.50	6.70	9.08	5.49	6.78	9.63	

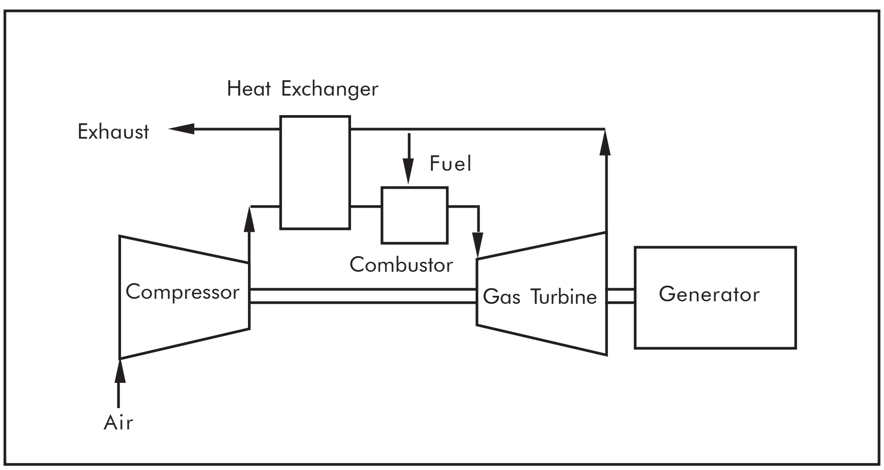
Annex 19
Microturbine Power Systems

Microturbines are 25 kW to 250 kW turbine engines that run on natural gas, gasoline, diesel or alcohol. Derived from aircraft auxiliary power systems and automotive designs, microturbines have one or two shafts that operate at speeds of up to 120,000 RPM for single shaft engines and 40,000 RPM for duel shaft engines. Microturbines are a relatively new technology and are only now being sold commercially. They have capital cost of US$500 to US$1,000/kW and electrical efficiencies of 20 to 30 percent. Their main advantage is their small size and relatively low NO_x emissions. Main markets for this power generation technology include light industrial and commercial facilities that often pay higher price for electricity. The modest heat output can also be used for low-pressure steam or hot water requirements. According to trial calculation of EPRI, generating cost is reduced 40 percent by 100 percent cogeneration system.

Technology Description

Figure A19.1 shows the schematic of microturbine burning natural gas. Note that the basic layout is that of a Brayton cycle machine, identical to a larger scale simple cycle or closed cycle gas turbine plant.

Figure A19.1: Gas-fired Microturbine Power System



Environmental and Economic Assessment

Table A19.1 provides assumed design parameters and operating characteristics for a gas-fired microturbine.

Table A19.1: Microturbine Power Plant Design Assumptions

Capacity	*150 kW*
Capacity Factor (%)	80
Gas Turbine Inlet Temperature	950 degree
Operate Speeds	90,000 RPM
Fuel-type	Natural Gas
Thermal Efficiency (LHV, %)	30
Auxiliary Power Ratio (%)	0
Life Span (year)	20
Generated Electricity (MWh/year)	1,051

Source: The Institute of Applied Energy (Japan).

The environmental impacts of microturbines are extremely low – just 30-60 mg/Nm^3 for NO_x and 670 g–CO_2/net-kWh.

Table A19.2 provides estimated capital costs of a gas-fired microturbine.

Table A19.2: Microturbine Power System 2005 Capital Costs (US$/kW)

Equipment	*830*
Civil	10
Engineering	10
Erection	20
Process Contingency	90
Total	**960**

Table A19.3 provides the results of the generation cost calculations, in line with the methodology described in Annex 2.

Table A19.3: Microturbine Power Plant 2005 Generating Costs (US¢/kWh)

Levelized Capital Cost	*1.46*
Fixed O&M Cost	1.00
Variable O&M Cost	2.50
Fuel Cost	26.86
Total	**31.82**

Future Cost and Uncertainty Analysis

The two main American microturbine manufacturers have announced target prices corresponding to their long-term plans for technology development and manufacturing scale-up. These forecasts are roughly half the current as-delivered cost (Table A19.4). We assume that the target price will be reached in 2025, a cost reduction trajectory equivalent to a decline of US$20 per year over the study period.

Table A19.4: Microturbine Power System Target Price

Maker	*US$/kW*
Elliott (United States)	400
Capstone (United States)	500

Source: The Institute of Applied Energy (Japan).

The cost of power plants changes with conditions such as maker, location, fuel price and so on. In this section, it is assumed that all costs have ± 20 percent variability around the probable values. This uncertainty assumption together with the capital cost projections yields the projected capital and generating costs shown in Table A19.5.

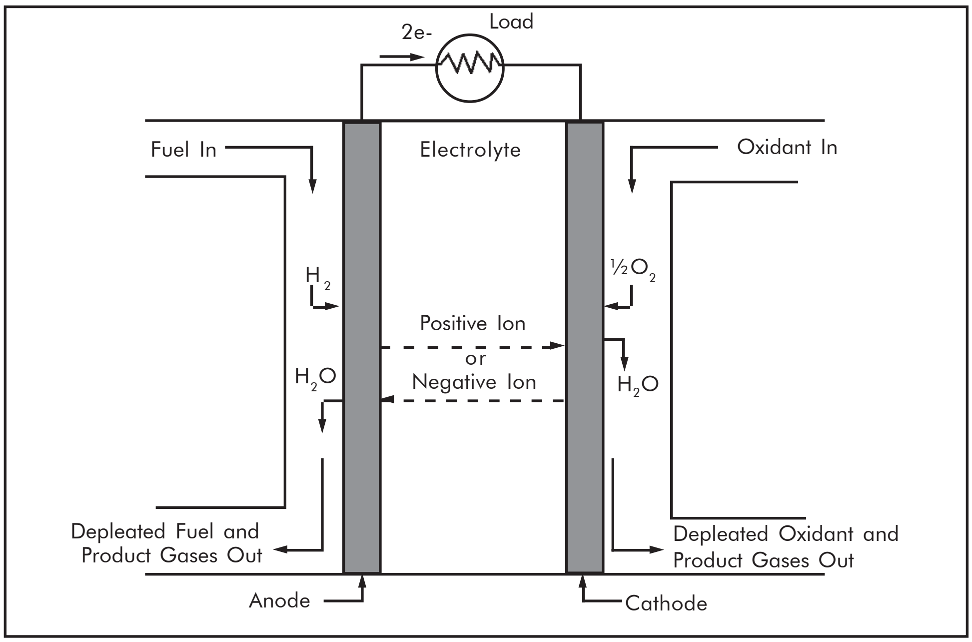
Table A19.5: Microturbine Power Plant Projected Capital and Generating Costs

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
Capital Cost (US$/kW)	830	960	1,090	620	780	910	500	680	810
Generating Cost (US¢/kWh)	30.4	31.8	33.9	28.8	30.7	33.5	28.5	30.7	34.2

Annex 20
Fuel Cells

Fuel cells produce direct current electricity through an electrochemical process. Reactants, most typically H and air, are continuously fed to the fuel cell reactor, and power is generated as long these reactants are supplied (Figure A20.1). A detailed description of the fuel cell technology status and applications is provided in the *Fuel Cell Handbook*.[57]

Figure A20.1: Operating Principles of a Fuel Cell



Source: Fuel Cell Handbook, October 2000.

Technology Description

Operation of complete, self-contained, natural gas-fueled small (less than 12 MW) power plants has been demonstrated using four different fuel cell technologies. They are: PEFC, PAFC, MCFC, and SOFC. Over 200 PAFC have been sold worldwide since the early 90s, when 200 kW PAFC units were commercially offered by IFC. These systems were installed at natural gas-fueled facilities and are currently in operation. Lower capacity units operate at atmospheric pressure while an 11 MW system that went into operation at the Tokyo Power Company's Geothermal Station in 1991, operates at eight atmospheres. MCFC units rated at 300 kW are also considered ready for commercialization.

[57] *Fuel Cell Handbook, Fifth Edition, U.S. DOE Office of Fossil Energy's National Energy Technology Laboratory, October 2000.*

PEFC and PAFC operate at low temperatures, less than 260°C (500°F), while MCFC and SOFC operate at high temperatures, 650-1,010°C (1,200-1,850°F). Operating pressures also vary from atmospheric pressures to about eight atmospheres depending on the fuel cell type and size. Pressurization generally improves fuel cell efficiency,[58] but increases parasitic load and capital cost. It could also lead to operational difficulties such as corrosion, seal deterioration and reformer catalyst deactivation. Most fuel cells require a device to convert natural gas or other fuels to a H-rich gas stream. This device is known as a fuel processor or reformer.

Fuel cell system performance is also sensitive to a number of contaminants. In particular, PEFC is sensitive to CO, S and ammonia (NH_3); PAFC to CO and S; MCFC to S and hydrogen chloride (HCl); and SOFC to S. Fuel cell system design must reduce these contaminants to levels that are acceptable to fuel cell manufacturers.

Environmental and Economic Assessment

We assume the design parameters and operating characteristics for fuel cells as shown in Table A20.1.

Table A20.1: Fuel Cell Power System Design Assumptions

	200 kW Fuel Cell	*5 MW Fuel Cell*
Capacity	200 kW	5 MW
Capacity Factor (%)	80	80
Fuel-type	Natural Gas	Natural Gas
Electrical Efficiency (LHV, %)[59]	50	50
Auxiliary Power Ratio (%)	1	1
Life Span (year)	20	20
Gross Generated Electricity (MWh/year)	1,402	35,040
Net Generated Electricity (MWh/year)	1,388	34,690

[58] *Sy A. Ali and Robert R. Mortiz, The Hybrid Cycle: Integration of Turbomachinery with a Fuel Cell, ASME, 1999.*
[59] *Operating fuel cells as a CHP plant can increase fuel cell plant efficiency to 70 percent.*

Fuel cells have essentially negligible air emissions characteristics, as shown in Table A20.2.

Table A20.2: Fuel Cell Power System Air Emissions

	Emission Standard	*Fuel Cell Gas*
PM	50 mg/Nm^3	–
SO_x	2,000 mg/Nm^3 (<500 MW:0.2 tpd/MW)	–
NO_x	Gas: 320 mg/Nm^3; Oil: 460	1.4-3

Note: "–" means no cost needed.

Fuel cells do generate CO_2 emissions at a level comparable to direct combustion of gas (Table A20.3).

Table A20.3: Fuel Cell Power System Carbon Dioxide Emissions

	200 kW Fuel Cell (CF=80%)	*5 MW Fuel Cell (CF=80%)*
	Gas	Gas
g-CO_2/kWh	370-465	370-465
10^3 Ton/Year	0.52-0.65	13-16

Table A20.4 shows the estimated capital cost of a 200 kW and 5 MW fuel cells.

Table A20.4: Fuel Cell Power System 2005 Capital Costs (US$/kW)

Items	*200 kW Fuel Cell*	*5 MW Fuel Cell*
Equipment	3,100	3,095
Civil	0	5
Engineering	0	0
Erection	20	10
Process Contingency	520	520
Total	**3,640**	**3,630**

Table A20.5 shows the results of converting the capital cost into per kWh cost, assuming a 20-year service life and using the methodology described in Annex 2.

Table A20.5: Fuel Cell Power System 2005 Generating Costs (US¢/kWh)

Items	*200 kW Fuel Cell*	*5 MW Fuel Cell*
	Natural Gas	*Natural Gas*
Levelized Capital Cost	5.60	5.59
Fixed O&M Cost	0.10	0.10
Variable O&M Cost	4.50	4.50
Fuel Cost	16.28	4.18
Total	**26.48**	**14.37**

Future Cost and Uncertainty Analysis

The actual equipment cost for fuel cells is expected to decrease in the future due to technological improvements and reduced manufacturing costs. Cost projections reflecting these decreases are given in Table A20.6.

Table A20.6: Fuel Cell Power System Projected Capital and Generating Costs

	2005	*2010*	*2015*
200 kW Fuel Cell			
Total Installed Cost (US$/kW)	3,640	2,820	2,100
Total Generating Costs (US¢/kWh)	**26.5**	**24.7**	**23.7**
5 MW Fuel Cell			
Total Installed Cost (US$/kW)	3,630	2,820	2,100
Total Generating Costs (US¢/kWh)	**14.4**	**12.7**	**11.7**

The cost of power plants often changes with conditions such as maker, location, fuel price and so on. In this section, we assume that all costs are variable within a ±20 percent range, with the results shown in Table A20.7 and Table A20.8.

Table A20.7: Uncertainty in Fuel Cell Capital Costs Projections

	2005			*2010*			*2015*[1]		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
200 kW Fuel Cell	3,150	3,640	4,120	2,190	2,820	3,260	1,470	2,100	2,450
5 MW Fuel Cell	3,150	3,630	4,110	2,180	2,820	3,260	1,470	2,100	2,450

Table A20.8: Uncertainty in Fuel Cell Generating Costs Projections

	2005			*2010*			*2015*		
	Min	*Probable*	*Max*	*Min*	*Probable*	*Max*	*Min*	*Probable*	*Max*
200 kW Fuel Cell	25.2	26.5	28.2	22.8	24.7	26.6	21.5	23.7	25.8
5 MW Fuel Cell	13.2	14.4	15.8	11.0	12.7	14.4	9.6	11.7	13.4

Annex 21
Description of Economic Assessment Methodology

Assessment results for generation technologies vary according to the operating environment. During an August 2004 inception meeting, the study team suggested values for key operating assumptions, including average unit size, life span, output and capacity factor. Consultation with the World Bank Task Managers yielded the operating parameter assumptions and ranges specified in Table A21.1, which were then used in the assessment process.

Table A21.1: Power Generation Technology Configurations and Design Assumptions

Generating-types	*Life Span (Year)*	*Off-grid*		*Mini-grid*		*Grid-connected*			
						Base Load		*Peak*	
		Capacity	*CF (%)*	*Capacity*	*CF (%)*	*Capacity*	*CF (%)*	*Capacity*	*CF (%)*
Solar-PV	20	50 W, 300 W	20						
	25			25 kW	20	5 MW	20		
Wind	20	300 W	25	100 kW	25	10 MW	30		
						100 MW			
PV-wind Hybrids	20	300 W	25	100 kW	30				
Solar Thermal With Storage	30					30 MW	50		
Solar Thermal Without Storage	30					30 MW	20		
Geothermal Binary	20			200 kW	70				
Geothermal Binary	30					20 MW	90		
Geothermal Flash	30					50 MW	90		
Biomass Gasifier	20			100 kW	80	20 MW	80		
Biomass Steam	20					50 MW	80		
MSW/Landfill Gas	20					5 MW	80		
Biogas	20			60 kW	80				
Pico/Micro-hydro	5	300 W	30						
	15	1 kW	30						
	30			100 kW	30				
Mini-hydro	30					5 MW	45		
Large-hydro	40					100 MW	50		
Pumped Storage Hydro	40							150 MW	10
Diesel/Gasoline	10	300 W,	30						
Generator	20	1 kW		100 kW	80	5 MW	80	5 MW	10
Microturbines	20			150 kW	80				
Fuel Cells	20			200 kW	80	5 MW	80		
Oil/Gas Combined Turbines	25							150 MW	10
Oil/Gas Combined Cycle	25					300 MW	80		
Coal Steam SubCritical	30					300 MW	80		
Sub, SC, USC	30					500 MW	80		
Coal IGCC	30					300 MW	80		
	30					500 MW	80		
Coal AFB	30					300 MW	80		
	30					500 MW	80		
Oil Steam	30					300 MW	80		

Assessment results will also vary widely according to the values assumed for key economic parameters. Following the World Bank guidance contained in the study's terms of reference, we used a discount rate[60] set at 10 percent/year. We performed and expressed all economic analysis in constant June 2004 US dollars. Economic cost equivalent to international competitive price of machines, materials and fuel are used. Transport costs are included and shown separately, and only labor expenses are assumed to differ between regions.

Cost Formulations for Generation

The generating cost of each resource is simply the sum of capital cost and operating cost, expressed on a levelized basis. This formulation (Equation 1) reflects an explicitly *economic* analysis, as opposed to a *financial* analysis.

Generating Cost = Capital Cost + Operating Cost *(Equation 1)*

Capital cost is calculated on a unit basis using Equation 2. Costs which do not directly contribute to power generation, such as land, roads, offices, and so on, and so forth, are not included in the calculation.

Unit Capital Cost (US$/kW) = (Equipment Cost including Engineering + Civil Cost + Construction Cost + Process Contingency) ÷ Generation Capacity (kW)

(Equation 2)

Capital cost can be expressed in levelized terms through Equation 3 below:

$$Levelized\ Capital\ Cost\,(\$/kWh) = \frac{\sum \frac{Cn}{(1+r)^n}\,(\$)}{\sum \frac{En}{(1+r)^n}\,(kWh)}$$

(Equation 3)

Where *r* is the discount rate, *n* is the life span, C*n* is the capital cost incurred in the *nt*h year and *En* is the net electricity supplied in the *nt*h year.

[60] *Used for calculating levelized cost.*

Operating cost can be calculated using Equation 4 below,

Operating Cost (US$/kWh) = {Fixed O&M Cost (US$/yr) +Variable O&M Cost (US$/yr)+ Levelized Fuel Cost (US$/yr)}÷ Net Electricity (kWh/yr)

(Equation 4)

Where:

Fixed O&M Cost (US$/yr) = Operating Labor, General and Administrative, Insurance, other

Variable O&M Cost (US$/yr) = Maintenance Labor and Material, Supplies and Consumables, Water and Water Treatment, other

Levelized Fuel Cost (US$/yr) = Levelized Heat Unit Price (US$/J) x Gross Heat Consumption (J/kWh)×Gross Electricity (kWh/yr)

and:

Net Electricity (kWh/yr) = Gross Electricity (kWh/yr) – Auxiliary Electricity (kWh/yr)

Cost Formulations for Distribution

Distribution cost (in US$/kWh) is calculated by Equation 5 below:

Distribution Cost = Levelized Capital Cost + O&M Cost + Cost of Losses

(Equation 5)

Where:

$$\text{Levelized Capital Cost (US\$/year)} = \text{Capital Cost (US\$)} \times \frac{1-R}{1-R^{n}}$$

Levelized Capital Cost (US¢/kWh) = Capital Cost (US$) x $\frac{1-R}{1-R^n}$ /(Annual Generated Electricity (kWh) – Annual Distribution Losses (kWh)) x 100

R = 1 / (1+r); r = Discount Rate (= 0.1); n = Life Time (assumed = 20 years)

Capital Cost = Materials Cost (MC) + Labor Cost
= Poles MC + Wires MC + Transformers MC + Other MCs + Labor Cost

Distribution Losses (kWh) = Generated Electricity (kWh) x Distribution Loss Rate

O&M Cost (US$/yr) = Capital Cost (US$) x O&M Annual Cost Rate

O&M Annual Cost Rate (US¢/kWh) = O&M Cost (US$/year) / (Annual Generated Electricity – Annual Distribution Losses) x 100

Loss Cost (US¢/kWh)
= (Generating Cost [US¢/kWh] x Annual Distribution Losses [kWh])/
(Annual Generated Electricity [kWh] – Annual Distribution Losses [kWh])

The unit capital cost for distribution (in US$/kW) is calculated per Equation 6 below:

Unit Distribution Capital Cost = Capital Cost/(Rated Output of Power Station (kW)-Distribution Losses (kW))

(Equation 6)

Cost Formulations for Transmission

Transmission cost (in US$/kWh) and unit transmission cost (US$/kW) is calculated in the same way as distribution costs, per Equations 7 and 8 below:

Transmission Costs = Levelized Capital Cost + OM Cost + Loss Cost

(Equation 7)

Unit Capital Transmission Cost = Capital Cost/(Rated Output of Power Station (kW)- Transmission Losses (kW))

(Equation 8)

Transmission capital cost is calculated as a function of the distance from the generation area to the grid connecting point. Transmission losses are based on the I-squared losses of a representative transmission line, both as shown below:

Transmission Capital Cost	= Transmission Capital Cost /km x Distance (Line km) = Materials Cost (MC)/km + Labor Cost/km = Poles or Steel tower MC/km + Wires MC/km + Other MCs/km + Labor Cost/km
Transmission Losses (kW/km)	= $3I^2r$ / 1000 n = (rP^2/V^2) / (1000 n)
Transmission Losses (kWh/ km -year)	= ($3I^2$ r / 1000 n) x 8,760 C = Transmission Losses (kW/km) x 8,760 C

Where: I = Current of line at Rated Capacity of Generation (A)
r = Resistance (Ω/km)
P = Rated Capacity of Generation (kW)
V = Nominal Voltage (kV)
C = Capacity Factor
P = $\sqrt{3}$ x IV
Power Factor = 1.0
n = "The number of circuits" x "the number of bundles"

Cost Formulations for Distribution

India is selected as the baseline country as per the overall methodology. Average distribution capital costs over normal terrain in India are shown in Table A21.2 and the component breakdown of capital cost for an 11kV line is shown in Table A21.3.

Table A21.2: Average Capital Costs of Distribution (per km)

Item	*Average Capital Cost*	*Specifications*
High-voltage Line	5,000 (US$/km)	33 kV-11 kV
Low-voltage Line	3,500 (US$/km)	230 V
Transformer	3,500 (US$/unit)	50 kVA ,3φ11kV/400/230 V

Source: Interviews with Indian electric power companies conduced by TERI, November 2004.

Table A21.3: Proportion of Capital Costs by Component of a 11 kV Line

	Item	*Specifications*	*Proportion of Capital Cost (%)*
	Poles	8 m, Concrete	13
Materials	Wires	3.1 km 30mm^2 ACSR	39
	Other Materials	Insulator, Arms, and so on, and so forth	27
	Labor		21

Source: Reducing the Cost of Grid Extension for Rural Electrification, NRECA, 2000.

Distribution capital costs are levelized as per the methodology described above, and O&M cost calculated as 2 percent of the initial capital cost annually. Both can be expressed on a per-circuit-km basis (Table A21.4).

Table A21.4: Levelized Capital Costs and O&M Costs (per km)

Item	*Levelized Capital Cost*	*O&M Cost*
High-voltage Line	535 (US$/km-year)	100 (US$/km-year)
Low-voltage Line	375 (US$/km-year)	70 (US$/km-year)
Transformer	375 (US$/unit-year)	70 (US$/unit-year)

The capital and levelized costs of distribution including the costs of losses and O&M are shown in Table A21.5. A value of 12 percent is used for the distribution loss percentage.[61]

Table A21.5: Capital and Variable Costs for Power Delivery, by Power Generation Technology

				Mini-grid				
Generating-types	*Rated*	*CF*		*US¢/kWh*			*US$/kW*	
	Output	*(%)*	*2005*	*2010*	*2015*	*2005*	*2010*	*2015*
Solar-PV	25 kW	20	7.42	6.71	6.14	56	56	56
Wind	100 kW	25	3.80	3.61	3.49	193	193	193

(continued...)

[61] *Distribution Loss Percentage = Average T&D Loss Percentage x Distribution Loss Rate = 17.2% x 0.7 = 12%.*

(...Table A21.5 continued)

Generating Types	*Rated Output*	*CF (%)*	*Mini-grid US¢/kWh 2005*	*2010*	*2015*	*US$/kW 2005*	*2010*	*2015*
PV-wind Hybrids	100 kW	30	5.09	4.72	4.42	193	193	193
Geothermal	200 kW	70	2.53	2.38	2.34	193	193	193
Biomass Gasifier	100 kW	80	1.58	1.51	1.48	193	193	193
Biogas	60 kW	80	1.03	0.99	0.99	56	56	56
Micro-hydro	100 kW	30	2.43	2.36	2.36	193	193	193
Diesel/Gasoline	100 kW	80	3.08	2.94	2.97	193	193	193
Microturbines	150 kW	80	4.69	4.54	4.54	193	193	193
Fuel Cells	200 kW	80	3.99	3.72	3.58	193	193	193

Transmission Cost Calculation

We assume voltage level and line-types suited to power station size as shown in Table A21.6.[62]

Table A21.6: Voltage Level and Line-type Relative to Rated Power Station Output

Rated Output of Power Station (MW)	*Representative Voltage Level (kV)*	*Line-type*	*Capital Cost (US$/km)*
5	69	DRAKE 1cct	28,177
10	69	DRAKE 1cct	28,177
20	69	DRAKE 1cct	28,177
30	138	DRAKE 1cct	43,687
100	138	DRAKE 2cct	78,036
150	230	DRAKE 2cct	108,205
300	230	DRAKE (2) 2cct	151,956

Source: Chubu Electric Power Company Transmission Planning Guidelines.

[62] These voltage levels and line-types are decided upon by the "Alternative Thermal Method," which is used for transmission power plan in Chubu Electric Power Company.

As with the distribution calculation, capital and O&M costs can be expressed on a per-circuit-km annualized basis by levelizing the capital cost and assuming annual O&M costs are a fixed fraction of capital costs (Table A21.7); transmission losses per kilometer are in Table A21.8.

Table A21.7: Levelized Capital Costs and O&M Costs per Unit

Rated Output (MW)	*Levelized Capital Cost (US$/km-year)*	*O&M Cost (US$/km-year)*
5	3,015	845
10	3,015	845
20	3,015	845
30	4,675	1,311
50	4,675	1,311
100	8,350	2,341
150	11,578	3,246
300	16,259	4,559

Table A21.8: Transmission Losses

Generating-types	*Output (MW)*	*CF (%)*	*Transmission Losses (kWh/km-year)*	*Transmission Losses (kW/km)*
Solar-PV	5	20	823	0.47
Wind	10	30	4,941	1.88
Wind	100	30	61,627	23.45
Solar-thermal	30	20	7,393	4.22
Geothermal	50	90	92,400	11.72
Biomass Gasifier	20	80	52,560	7.50
Biomass Steam	50	80	82,134	11.72
MSW/Landfill Gas	5	80	3,294	0.47
Mini-hydro	5	45	1,853	0.47
Large-hydro	100	50	102,711	23.45
Pumped Storage Hydro (peak)	150	10	16,635	18.99
Diesel/Gasoline Generator	5	80	3,294	0.47
Diesel/Gasoline Generator (peak)	5	10	412	0.47

(continued...)

(...Table A21.8 continued)

Generating-types	*Output (MW)*	*CF (%)*	*Transmission Losses (kWh/km-year)*	*Transmission Losses (kW/km)*
Fuel Cells	5	80	3,294	0.47
Oil/Gas Combined Turbines (peak)	150	10	16,635	18.99
Oil/Gas Combined Cycle	300	80	266,164	37.98
Coal Steam	300	80	266,164	37.98
Coal IGCC	300	80	266,164	37.98
Coal AFB	300	80	266,164	37.98
Oil Steam	300	80	266,164	37.98

The capital and levelized costs of transmission are calculated as per the method described above, and shown in Table A21.9.

Table A21.9: Capital and Delivery Costs of Transmission (2004 US$)

Generating-types	*Rated Output (MW)*	*CF (%)*	*(US¢ x 10^{-2})/(kWh-km)*			*US$/(kW-km)*		
			2005	*2010*	*2015*	*2005*	*2010*	*2015*
Solar-PV	5	20	4.80	4.75	4.71	5.64	5.64	5.64
Wind	10	30	1.60	1.58	1.57	2.82	2.82	2.82
Wind	100	30	0.54	0.53	0.52	0.78	0.78	0.78
Solar Thermal Without Thermal Storage	30	20	0.64	0.62	0.61	1.46	1.46	1.46
Geothermal	50	90	0.25	0.25	0.25	0.87	0.87	0.87
Biomass Gasifier	20	80	0.54	0.53	0.52	1.41	1.41	1.41
Biomass Steam	50	80	0.31	0.30	0.30	0.87	0.87	0.87
MSW/Landfill Gas	5	80	1.16	1.16	1.16	5.64	5.64	5.64
Mini-hydro	5	45	2.02	2.02	2.02	5.64	5.64	5.64
Large-hydro	100	50	0.37	0.37	0.37	0.78	0.78	0.78
Pumped Storage Hydro (peak)	150	10	1.57	1.56	1.55	0.72	0.72	0.72
Diesel/Gasoline Generator	5	80	1.19	1.18	1.18	5.64	5.64	5.64
Diesel/Gasoline Generator (peak)	5	10	8.98	8.97	8.97	5.64	5.64	5.64

(continued...)

(...Table A21.9 continued)

Generating-types	*Rated Output (MW)*	*CF (%)*	*(US¢ x 10^{-2})/(kWh-km)*			*US$/(kW-km)*		
			2005	*2010*	*2015*	*2005*	*2010*	*2015*
Fuel Cells	5	80	1.24	1.22	1.21	5.64	5.64	5.64
Oil/Gas Combined Turbines (peak)	150	10	1.29	1.28	1.28	0.72	0.72	0.72
Oil/Gas Combined Cycle	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Coal Steam	300	80	0.16	0.15	0.15	0.51	0.51	0.51
Coal AFB	300	80	0.15	0.15	0.15	0.51	0.51	0.51
Coal IGCC	300	80	0.17	0.16	0.16	0.51	0.51	0.51
Oil Steam	300	80	0.19	0.19	0.18	0.51	0.51	0.51

Forecasting Capital Costs of Generation

The forecast value of the future price in 2010 and 2015 is calculated by considering the decrease of the future price as a result of both technological innovation and mass production. A forecast decrease in capital cost is done for each generation technology group as shown in Table A21.10, reflecting the relative maturity of each generation technology.

Table A21.10: Forecast Rate of Decrease in Power Generation Technologies

Decrease in Capital Cost (2004 to 2015)	*Generating Technology-type*
0%-5%	Geothermal, Biomass-steam, Biogas, Pico/Micro Hydro, Mini-hydro, Large-hydro, Pumped Storage, Diesel/Gasoline Generator, Coal-steam (SubCritical and SC), Oil Steam
6%-10%	Biomass Gasifier, MSW/Landfill, Gas Combustion, Gas Combined Cycle, Coal Steam (USC), Coal AFBC
11%-20%	Solar-PV, Wind, PV-wind Hybrids, Solar-thermal, Coal-IGCC
>20%	Microturbine, Fuel Cells

Uncertainty Analysis

Key uncertainties considered include fuel costs, future technology cost and performance, and resource risks. Each was systematically addressed using a probabilistic approach based on the "Crystal Ball" software package. All uncertainty factors are estimated in a band, and generating costs are calculated by Monte Carlo Simulation. These probabilistic methods can also be applied to some other operational uncertainties, such as estimating the capacity factor of wind. The particular applications of uncertainty analysis techniques are described within each technology section. Generally speaking, the uncertainty analysis proceeds as follows:

- Uncertainty factors are chosen;
- High and low of uncertainty factors are set;[63] and
- Additional particular conditions are set (for example, resource variability, fuel cost, and so on, and so forth).

Accommodating the Intermittency of Renewable Energy Technologies

In case of solar-PV, wind-PV and wind-hybrids in a mini-grid area or off-grid configuration, battery costs or costs of a backup generator are included in the costs of the power system in order to smooth stochastic variations in the available resource and provide for a reliable power output. If the solar-PV or wind-PV system is grid-connected, intermittency is not a significant problem (unless renewable power penetration levels are very high) because the grid can absorb and accommodate such intermittency without requiring a back-up power supply.

Conformance with the Costing Methods Used in EPRI TAG-RE 2004

The objective of this study is to provide a consistent set of technical and economic assessments on a broad range of power generation technologies, so that the performance and costs of these technologies in various settings can be easily and impartially compared. In searching for an assessment methodology, we chose the general approach and specific cost formulas contained in the Renewable Energy Technical Assessment Guide – TAG-RE: 2004,[64] TAG-RE 2004, published by Electric Power Research Institute (EPRI). This source book provides a comprehensive methodology for assessing various power generating technologies, including RETs, and is the source of the detailed cost formulas used in the economic assessment. These formulations are described below.

[63] *In order to make calculation results consistent, basic variables are set to ± 20%.*
[64] *EPRI (Electric Power Research Institute) publishes a series of Technology Assessment Guides, or TAGs, which contains very useful information about various generation, transmission, distribution and environmental technologies. This study relied on the quantification methods contained in Renewable Energy Technical Assessment Guide – TAG-RE: 2004.*

Capital Cost Formulas

TAG-RE 2004 defines capital cost formulas for regulated utilities. There are three related formulations of capital cost offered – (a) total plant cost (TPC), (b) total plant investment (TPI) and (c) total capital requirement (TCR):

(a) TPC = (Process Facilities Capital Cost + General Facilities Capital Cost + Engineering Cost) + (Home Office Overhead Cost + Project & Process Contingency)

(Equation 9)

(b) TPI = TPC + adjustment for the escalation[65] of capital costs during construction + AFUDC

(Equation 10)

Where *AFUDC* is *allowance for funds used during construction*, representing the interest accrued on each expense from the date of the expense until the completion and commissioning of the facility. AFUDC is assumed to be zero, because the construction period is short in renewable generation systems. With an interest rate of 5-8 percent, and a two to five year construction period, typical for large hydropower plants, the effect of AFUDC could add several percentage points to the TPI.

(c) *TCR = TPI + Owners' Costs*

(Equation 11)

Where *owners' costs* include land and property tax, insurance, preproduction, start-up and inventory costs. However, in this study, owners' costs are disregarded as negligible.

After considering these three available formulations, we selected TPC as being the most useful for assessment purposes. The TPC formulation is capable of capturing the key differences in capital cost structure between the 22 generation technologies being assessed, without introducing additional complexities associated with financing, taxes and insurance, and other costs which are largely country-driven. Our use of TPC represents a strictly economic formulation of costs, allowing the results to be easily transferred from one country to another. A financial formulation of costs can then be easily overlaid onto TPC, which will, then, be

[65] *The escalation rate adjustment for capital costs during construction is assumed to be zero.*

reflective to country-specific conditions affecting power plant financing. We reiterate our capital cost formulation below:

Capital Cost = TPC = (Process Facilities Capital Cost + General Facilities Capital Cost + Engineering Cost) + (Home Office Overhead Cost + Project & Process Contingency)

(Equation 12)

= Engineering Cost + Procurement Cost + Construction Cost + Contingency
= Equipment Cost + Civil Cost + Construction Cost + Contingency Cost

(Equation 13)

We note that *Process Facilities Capital Cost*, *General Facilities Capital Cost* and *Engineering Cost* are equivalent to EPC (engineering, procurement and construction) cost. EPC cost also includes *Equipment Cost* (engineering et al), civil cost and erection cost (labor, tool). We also roll together *Home Office Overhead Cost* and *Project and Process Contingency Cost* under the overall category of *Contingency Cost* to obtain the simple formulation of Equation (8), which will be used throughout the assessment.

Operating Cost and Generating Cost

TAG-RE 2004 defines operating cost by the following formula:

Operating Cost = (Fixed O&M Cost + Variable O&M Cost + Fuel Cost + Other Fixed Cost + Other Net Cash Flow) ÷ Net Electricity

(Equation 14)

Where *Other Fixed Cost* includes income taxes and debt service and *Other Net Cash Flow* includes cash reserves.

We disregard *Other Fixed Cost* and *Other Net Cash Flow* because they constitute less than 10 percent of Fixed O&M Cost, Variable O&M Cost and Fuel Cost. This allows us to simplify the Operating Cost formulation to:

Operating Cost = (Fixed O&M Cost + Variable O&M Cost + Fuel Cost) ÷ Net Electricity

(Equation 15)

We can then state the total power generation economic cost formulation as in TAG-RE 2004, and in this study as follows:

Generating Cost = Capital Cost + Operating Cost

(Equation 16)

Capacity Factor and Availability Factor

In order to express capital cost and operating cost on the same unit terms, we must know the hours of operation of the power generation technology. This section briefly describes how availability factor and capacity factor were used in expressing costs of different power generation technologies. Capacity factor is universally defined as "the ratio of the actual energy produced in a given period, to the hypothetical maximum possible." This definition applies regardless of power generation technology. We formulate the Capacity Factor calculation simply and universally as:

Capacity Factor = (Total MWh Generated in Period x 100)/Installed Capacity

(MW) x Period (hours)

(Equation 17)

Several formulations of Availability Factor are found in the literature. The most common one is that in use by the North American Reliability Council (NERC):

Availability Factor = Available Hours/Period Hours

(Equation 18)

Where *Available Hours* is the total *Period Hours* less forced outage, maintenance and planned outage hours.

Availability Factor is a straightforward concept for conventional power generation technologies but becomes more difficult to apply with RETs, where the availability factor is driven by the renewable resource availability. The literature is not helpful, as different formulations yield counter-intuitive results for expressing availability (Table 21.11). A wind generator "Availability Factor" is defined as that fraction of a period of hours when the wind generator could be providing power if wind was available within the right speed range. This statement of availability does not factor in generator outages due to resource unavailability and therefore cannot be used to compare the power output of conventional vs. renewable energy power generators.

Table A21.11: Availability Factor Values Found in the Power Literature

	Type of Power Station	*Value*
	Fossil	More than 75%
Renewable	Wind	95% 97%
	Solar-thermal	92.3%
	Ocean Wave	95%
	Geothermal	More than 90%

In consideration of this definitional difficulty, this report strictly relies on capacity factor as defined in Equation 12 for calculating generating costs on a per-kWh basis.

Fuel Price Forecast

Fuel prices used throughout this report are based on the IEA's (World Energy Outlook 2005) forecast. Since delivered fuel price is driven by the specific circumstances of exporting and importing countries, we developed the power generation cost estimation based on technology deployed and fuel consumed in India. This allows for the assessment results to be benchmarked and the numerical values extrapolated to other developing countries. We also levelize the forecast fuel price over the life span of each generating technology assessed. The procedure used for estimating fuel costs was as follows:

- The fuel used for a cost model is chosen (for example: Australian coal);
- The actual user end price is examined;
- The fixed component of fuel provision (transportation cost, local distribution cost, refining cost and so on, and so forth)) is examined, and the end use price divided into a fixed and variable components;
- The future price of fuel is calculated by linking the variable component of fuel price to the IEA's forecast base price;
- A levelized fuel price is calculated specific to the life span of each generating technology; and
- This levelized price is then used in the generating cost model.

Fuel price fluctuates according to market forces, affecting both conventional and hybrid generating costs. We incorporate price fluctuation in the case study by defining a range of price fluctuation capped at 200 percent of forecast base fuel price (Table A21.12).

Table A21.12: Fossil Fuel Price Assumptions (2004 US$)

Crude Oil *FOB Price of Crude Oil*				*US$/bbl (US$/GJ)*
		2005	2010	2015
Crude Oil (Dubai, Brent, WTI)	Base	53 (9.2)	38 (6.6)	37 (6.5)
	High	–	56 (9.8)	61 (10.6)
	Low	–	24 (4.2)	23 (4.0)

(continued...)

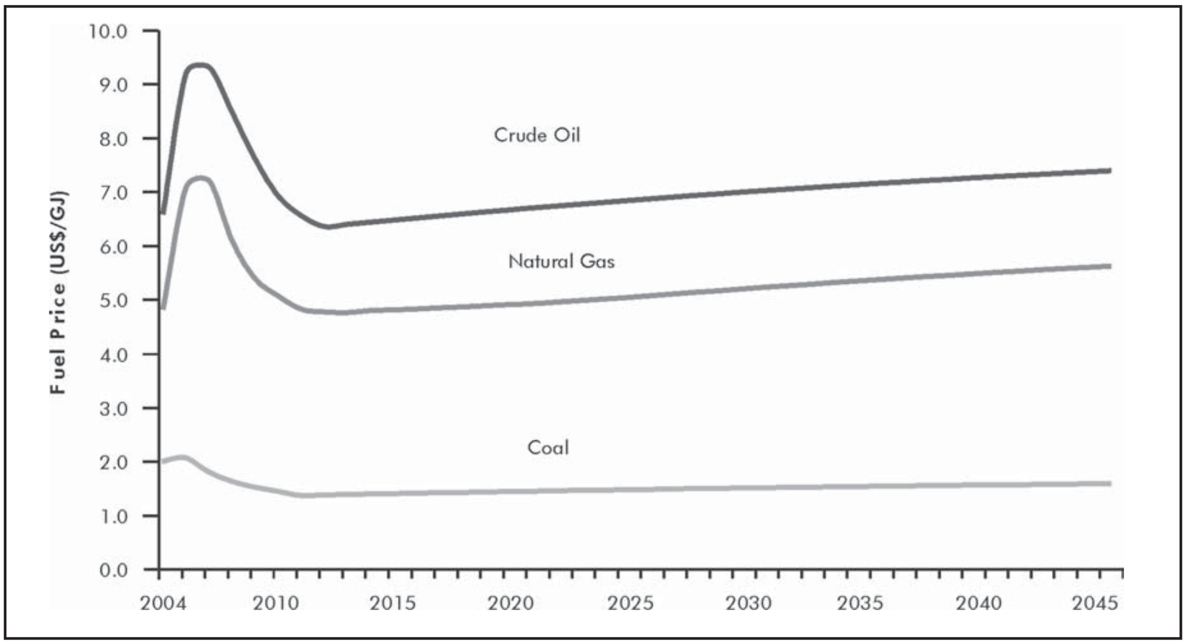
(...Table A21.12 continued)

Coal				
FOB Price of Coal				*US$/ton (US$/GJ)*
		2005	2010	2015
Coal (Australia)	Base	57 (2.07)	38 (1.38)	39 (1.42
	High	–	53 (1.92)	56 (2.04)
	Low	–	30 (1.10)	30 (1.10)
Natural Gas				
FOB Price of Natural Gas				*US$/MMBTU (US$/GJ)*
		2005	2010	2015
Gas (United States, European)	Base	7.5 (7.1)	5.1 (4.8)	5.1 (4.8)
	High	–	7.0 (6.6)	7.6 (7.2)
	Low	–	4.0 (3.8)	3.3 (3.1)

Note: "–" means no cost needed.

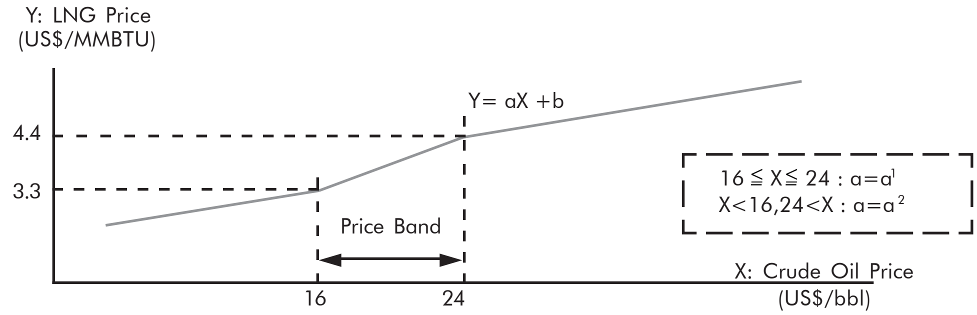
Figure A21.1 compares the base price trajectory of each fossil fuel source.

Figure A21.1: Fossil Fuel Price Assumptions



The liquefied natural gas (LNG) price is estimated separately using a Japanese forecasting formula (Japan is one of the world's largest LNG importing countries). The formula estimates LNG price based on crude oil price. When the oil price exceeds a certain price band, the slope of the curve is moderated to reflect the likelihood of risk hedging by both sellers and buyers. The procedure and results are shown in Figure 21.2.

Figure A21.2: Procedure for Estimating LNG Prices



LNG – Oil Price Curve

LNG Price (CIF) US$/MMBTU (US$/GJ)

		2005	2010	2015
	Base	6.5 (6.2)	5.5 (5.2)	5.5 (5.2)
LNG	High	–	6.7 (6.4)	7.1 (6.7)
	Low	–	4.6 (4.4)	4.5 (4.3)

Note: "–" means no cost needed.

Table A21.13 summarizes the results for all categories of end use fuels needed to assess generating costs for each power generation technology. In all cases, the values are user end price including fixed (for example, transportation cost and local distribution cost) and variable components. Typically, the fixed cost component for oil is about 20-50 percent of the total delivered end user price and a little higher for coal (30-50 percent) and lower for pipeline and LNG gas (20-30 percent). The bands of assumed price fluctuation for each forecast year are also shown.

Table A21.13: Other Fuel Costs (2004 US$/GJ)

		2005	2010	2015
Gasoline	Base	21.9	18.2	18.1
	High	–	22.7	23.9
	Low	–	14.9	14.6
Light Oil	Base	17.1	13.8	13.7
	High	–	17.9	18.9
	Low	–	10.8	10.5
Residual Oil	Base	7.0	5.2	5.2
	High	–	7.4	8.0
	Low	–	3.6	3.5

(continued...)

(...Table A21.13 continued)

		2005	2010	2015
Coal (India)	Base	1.51	1.60	1.63
	High	–	2.20	2.31
	Low	–	1.36	1.38
Coal (Australia)	Base	2.60	1.60	1.95
	High	–	2.45	2.57
	Low	–	1.63	1.63
Natural Gas (pipeline)	Base	7.2	5.1	5.1
	High	–	6.8	7.3
	Low	–	4.2	3.6

Note: "–" means no cost needed.

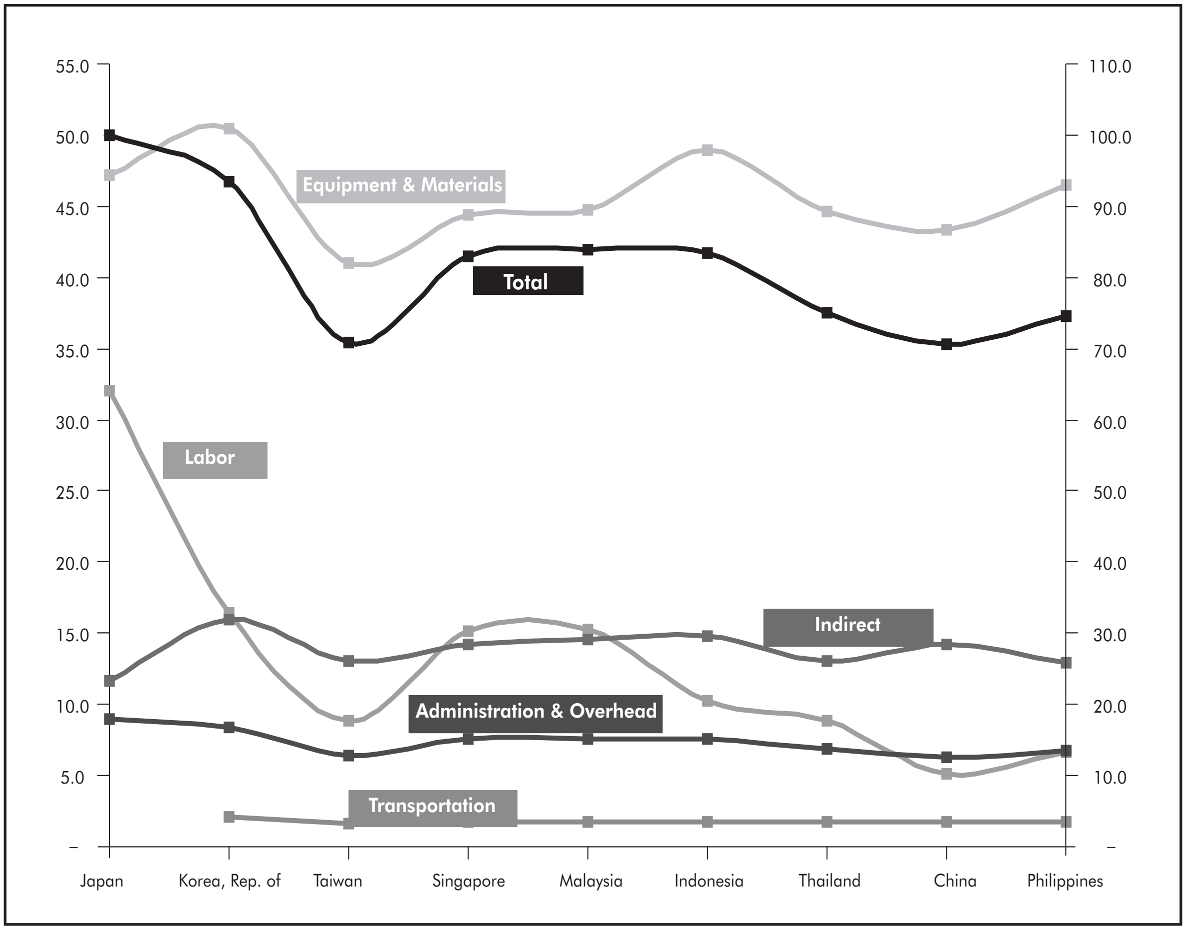
Regional Adjustment

One of the objectives of this study is to express all of the costing information (capital costs and operating costs) for the 22 power generation technologies on the same basis, including assumed location and fuel supply arrangements. However, all infrastructure capital and operating costs – engineering, equipment and material, construction, O&M, fuel, even contingency – vary depending on location. The largest variable requiring adjustment between different regions is labor cost, which is a major driver of both construction costs and O&M costs.

Location factors for the Asian region are provided in Figure A21.3. In addition to the data presented for developing countries, we also provide data for one developed economy (Japan). The data shown below suggests that the variation in costs of engineering, equipment and materials is quite small when procurement is done under International Competitive Bidding (ICB) or comparable guidelines. The labor costs vary from region to region, depending on GDP and per capita incomes.[66]

[66] *Useful references on this topic include: http://www.cia.gov/cia/publications/factbook, http://hdr.undp.org/reports/global/2003; http://www.worldfactsandfigures.com/gdp_country_desc.php; http://stats.bls.gov/fls/hcompsupptabtoc.htm; http://www.ggdc.net/dseries/totecon.html; and http://www-ilo-mirror.cornell.edu/public/english/employment/strat/publ/ep00-5.html.*

Figure A21.3: JSIM Location Factor for Southeast Asia (2002)



Annex 22

Power Generation Technology Capital Cost Projections

Table A22.1: Capital Costs Projections Power Generation Technology

SPV

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
50 W	Capital Cost	US$/kW	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	Fixed O&M	US¢/kWh	2.40	**3.00**	3.60	2.40	**3.00**	3.60	2.40	**3.00**	3.60
	Variable O&M	US¢/kWh	10.40	**13.00**	15.60	9,75	**13.00**	15.60	9.10	**13.00**	15.60
	Capacity Factor	%	15	**20**	25	15	**20**	25	15	**20**	25
300 W	Capital Cost	US$/kW	6,430	**7,480**	8,540	5,120	**6,500**	7,610	4,160	**5,780**	6,950
	Fixed O&M	US¢/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.00	2.00	**2.50**	3.00
	Variable O&M	US¢/kWh	6.40	**8.00**	9.60	6.00	**8.00**	9.60	5.60	**8.00**	9.60
	Capacity Factor	%	15	**20**	25	15	**20**	25	15	**20**	25
25 kW	Capital Cost	US$/kW	6,710	**7,510**	8,320	5,630	**6,590**	7,380	4,800	**5,860**	6,640
	Fixed O&M	US¢/kWh	1.20	**1.50**	1.80	1.20	**1.50**	1.80	1.20	**1.50**	1.80
	Variable O&M	US¢/kWh	5.60	**7.00**	8.40	5.25	**7.00**	8.40	4.90	**7.00**	8.40
	Capacity Factor	%	15	**20**	25	15	**20**	25	15	**20**	25
5 MW	Capital Cost	US$/kW	6,310	**7,060**	7,810	5,280	**6,190**	6,930	4,500	**5,500**	6,235
	Fixed O&M	US¢/kWh	0.78	**0.97**	1.16	0.78	**0.97**	1.16	0.78	**0.97**	1.16
	Variable O&M	US¢/kWh	0.19	**0.24**	0.29	0.18	**0.24**	0.29	0.17	**0.24**	0.29
	Capacity Factor	%	15	**20**	25	15	**20**	25	15	**20**	25

(continued...)

(...Table A22.1 continued)

Wind

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 W	Capital Cost	US$/kW	4,820	**5,370**	5,930	4,160	**4,850**	5,430	3,700	**4,450**	5,050
	Fixed O&M	US¢/kWh	2.79	**3.49**	4.19	2.79	**3.49**	4.19	2.79	**3.49**	4.19
	Variable O&M	US¢/kWh	3.92	**4.90**	5.88	3.74	**4.90**	5.88	3.55	**4.90**	5.88
	Capacity Factor	%	20	**25**	30	20	**25**	30	20	**25**	30
100 kW	Capital Cost	US$/kW	2,460	**2,780**	3,100	2,090	**2,500**	2,850	1,830	**2,300**	2,670
	Fixed O&M	US¢/kWh	1.66	**2.08**	2.50	1.66	**2.08**	2.50	1.66	**2.08**	2.50
	Variable O&M	US¢/kWh	3.26	**4.08**	4.90	3.11	**4.08**	4.90	2.96	**4.08**	4.90
	Capacity Factor	%	20	**25**	30	20	**25**	30	20	**25**	30
10 MW	Capital Cost	US$/kW	1,270	**1,440**	1,610	1,040	**1,260**	1,440	870	**1,120**	1,300
	Fixed O&M	US¢/kWh	0.53	**0.66**	0.79	0.53	**0.66**	0.79	0.53	**0.66**	0.79
	Variable O&M	US¢/kWh	0.21	**0.26**	0.31	0.20	**0.26**	0.31	0.18	**0.26**	0.31
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35
100 MW	Capital Cost	US$/kW	1,090	**1,240**	1,390	890	**1,080**	1,230	750	**960**	1,110
	Fixed O&M	US¢/kWh	0.42	**0.53**	0.64	0.42	**0.53**	0.64	0.42	**0.53**	0.64
	Variable O&M	US¢/kWh	0.18	**0.22**	0.26	0.17	**0.22**	0.26	0.15	**0.22**	0.26
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35

(continued...)

(...Table A22.1 continued)

PV-wind Hybrids

Capacity	*Contents*	*Units*		*2005*			*2010*			*2015*	
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 W	Capital Cost	US$/kW	5,670	**6,440**	7,210	4,650	**5,630**	6,440	3,880	**5,000**	5,800
	Fixed O&M	US¢/kWh	2.78	**3.48**	4.18	2.78	**3.48**	4.18	2.78	**3.48**	4.18
	Variable O&M	US¢/kWh	5.52	**6.90**	8.28	5.18	**6.90**	8.28	4.83	**6.90**	8.28
	Capacity Factor	%	20	**25**	30	20	**25**	30	20	**25**	30
100 kW	Capital Cost	US$/kW	4,830	**5,420**	6,020	4,030	**4,750**	5,340	3,420	**4,220**	4,800
	Fixed O&M	US¢/kWh	1.66	**2.07**	2.48	1.66	**2.07**	2.48	1.66	**2.07**	2.48
	Variable O&M	US¢/kWh	5.12	**6.40**	7.68	4.80	**6.40**	7.68	4.48	**6.40**	7.68
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35

(continued...)

(...Table A22.1 continued)

Solar-thermal

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
30 MW (without storage)	Capital Cost	U$/kW	2,290	**2,480**	2,680	1,990	**2,200**	2,680	1,770	**1,960**	2,120
	Fixed O&M	US¢/kWh	2.41	**3.01**	3.61	2.41	**3.01**	3.61	2.41	**3.01**	3.61
	Variable O&M	US¢/kWh	0.60	**0.75**	0.90	0.56	**0.75**	0.90	0.53	**0.75**	0.90
	Capacity Factor	%	15	**20**	25	15	**20**	25	15	**20**	25
30 MW (with storage)	Capital Cost	US$/kW	4,450	**4,850**	5,240	3,880	**4,300**	4,660	3,430	**3,820**	4,140
	Fixed O&M	US¢/kWh	1.46	**1.82**	2.18	1.46	**1.82**	2.18	1.46	**1.82**	2.18
	Variable O&M	US¢/kWh	0.36	**0.45**	0.54	0.34	**0.45**	0.54	0.31	**0.45**	0.54
	Capacity Factor	%	45	**50**	55	45	**50**	55	45	**50**	55

(continued...)

(...Table A22.1 continued)

Geothermal

Capacity	*Contents*	*Units*		*2005*			*2010*			*2015*	
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
200 kW Binary	Capital Cost	US$/kW	6,480	**7,220**	7,950	5,760	**6,580**	7,360	5,450	**6,410**	7,300
Fixed O&M		US¢/kWh	1.60	**2.00**	2.40	1.60	**2.00**	2.40	1.60	**2.00**	2.40
Variable O&M		US¢/kWh	0.80	**1.00**	1.20	0.79	**1.00**	1.20	0.77	**1.00**	1.20
20 MW Binary	Capital Cost	US$/kW	3,690	**4,100**	4,500	3,400	**3,830**	4,240	3,270	**3,730**	4,170
Fixed O&M		US¢/kWh	1.04	**1.30**	1.56	1.04	**1.30**	1.56	1.04	**1.30**	1.56
Variable O&M		US¢/kWh	0.32	**0.40**	0.48	0.31	**0.40**	0.48	0.31	**0.40**	0.48
50 MW Flash	Capital Cost	US$/kW	2,260	**2,510**	2,750	2,090	**2,350**	2,600	2,010	**2,290**	2,560
	Fixed O&M	US¢/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	US¢/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.23	**0.30**	0.36

(continued...)

(...Table A22.1 continued)

Biomass Gasifier

Capacity	*Contents*	*Units*		*2005*			*2010*			*2015*	
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
100 kW	Capital Cost	US$/kW	2,490	**2,880**	3,260	2,090	**2,560**	2,980	1,870	**2,430**	2,900
	Fixed O&M	US¢/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.27	**0.34**	0.41
	Variable O&M	US¢/kWh	1.26	**1.57**	1.88	1.22	**1.57**	1.88	1.18	**1.57**	1.88
	Fuel	US¢/kWh	2.13	**2.66**	3.19	2.13	**2.66**	3.46	2.13	**2.66**	3.72
20 MW	Capital Cost	US$/kW	1,760	**2,030**	2,300	1,480	**1,810**	2,100	1,320	**1,710**	2,040
	Fixed O&M	US¢/kWh	0.20	**0.25**	0.30	0.20	**0.25**	0.30	0.20	**0.25**	0.30
	Variable O&M	US¢/kWh	0.94	**1.18**	1.42	0.92	**1.18**	1.42	0.89	**1.18**	1.42
	Fuel	US¢/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.25	2.00	**2.50**	3.50

(continued...)

(...Table A22.1 continued)

Biomass-steam

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
50 MW	Capital Cost	US$/kW	1,500	**1,700**	1,910	1,310	**1,550**	1,770	1,240	**1,520**	1,780
	Fixed O&M	US¢/kWh	0.36	**0.45**	0.54	0.36	**0.45**	0.54	0.36	**0.45**	0.54
	Variable O&M	US¢/kWh	0.33	**0.41**	0.49	0.32	**0.41**	0.49	0.32	**0.41**	0.49
	Fuel	US¢/kWh	2.00	**2.50**	3.00	2.00	**2.50**	3.25	2.00	**2.50**	3.50

MSW/Landfill Gas

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
5 MW	Capital Cost	US$/kW	2,960	**3,250**	3,540	2,660	2,980	3,270	2,480	**2,830**	3,130
	Fixed O&M	US¢/kWh	0.09	**0.11**	0.13	0.09	0.11	0.13	0.09	**0.11**	0.13
	Variable O&M	US¢/kWh	0.34	**0.43**	0.52	0.33	0.43	0.52	0.32	**0.43**	0.52
	Fuel	US¢/kWh	0.80	**1.00**	1.20	0.80	1.00	1.30	0.80	**1.00**	1.40

Biogas

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
60 kW	Capital Cost	US$/kW	2,260	**2,490**	2,720	2,080	**2,330**	2,570	2,000	**2,280**	2,580
	Fixed O&M	US¢/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.27	**0.34**	0.41
	Variable O&M	US¢/kWh	1.23	**1.54**	1.85	1.21	**1.54**	1.85	1.19	**1.54**	1.85
	Fuel	US¢/kWh	0.88	**1.10**	1.32	0.88	**1.10**	1.43	0.88	**1.10**	1.54

(continued...)

(...Table A22.1 continued)

Pico/Micro-hydro

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 W	Capital Cost	US$/kW	1,320	**1,560**	1,800	1,190	**1,485**	1,770	1,110	**1,470**	1,810
	Fixed O&M	US¢/kWh	–	**–**	–	–	**–**	–	–	**–**	–
	Variable O&M	US¢/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.71	**0.90**	1.08
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35
1 kW	Capital Cost	US$/kW	2,360	**2,680**	3,000	2,190	**2,575**	2,950	2,090	**2,550**	2,990
	Fixed O&M	US¢/kWh	–	**–**	–	–	**–**	–	–	–	–
	Variable O&M	US¢/kWh	0.43	**0.54**	0.65	0.43	**0.54**	0.65	0.43	**0.54**	0.65
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35
100 kW	Capital Cost	US$/kW	2,350	**2,600**	2,860	2,180	**2,470**	2,750	2,110	**2,450**	2,780
	Fixed O&M	US¢/kWh	0.84	**1.05**	1.26	0.84	**1.05**	1.26	0.84	**1.05**	1.26
	Variable O&M	US¢/kWh	0.34	**0.42**	0.50	0.33	**0.42**	0.50	0.33	**0.42**	0.50
	Capacity Factor	%	25	**30**	35	25	**30**	35	25	**30**	35

(continued...)

(...Table A22.1 continued)

Mini-hydro

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
5 MW	Capital Cost	US$/kW	2,140	**2,370**	2,600	2,030	**2,280**	2,520	1,970	**2,250**	2,520
	Fixed O&M	US¢/kWh	0.59	**0.74**	0.89	0.59	**0.74**	0.89	0.59	**0.74**	0.89
	Variable O&M	US¢/kWh	0.28	**0.35**	0.42	0.28	**0.35**	0.42	0.28	**0.35**	0.42
	Capacity Factor	%	35	**45**	55	35	**45**	55	35	**45**	55

Large-hydro

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
100 MW	Capital Cost	US$/kW	1,930	**2,140**	2,350	1,860	**2,080**	2,290	1,890	**2,060**	2,280
	Fixed O&M	US¢/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	US¢/kWh	0.26	**0.32**	0.38	0.25	**0.32**	0.38	0.25	**0.32**	0.38
	Capacity Factor	%	40	**50**	60	40	**50**	60	40	**50**	60

Pumped Storage Hydro

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
150 MW	Capital Cost	US$/kW	2.860	**3,170**	3,480	2,760	**3,080**	3,400	2,710	**3,050**	3,380
	Fixed O&M	US¢/kWh	0.26	**0.32**	0.38	0.26	**0.32**	0.38	0.26	**0.32**	0.38
	Variable O&M	US¢/kWh	0.26	**0.33**	0.40	0.26	**0.33**	0.40	0.26	**0.33**	0.40

(continued...)

(...Table A22.1 continued)

Diesel/Gasoline Generator

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 W	Capital Cost	US$/kW	750	**890**	1,030	650	**810**	970	600	**800**	980
	Fixed O&M	US¢/kWh	–	**–**	–	–	**–**	–	–	**–**	–
	Variable O&M	US¢/kWh	4.00	**5.00**	6.00	3.97	**5.00**	6.00	3.94	**5.00**	6.00
	Fuel	US¢/kWh	47.39	**54.62**	64.40	40.55	**50.13**	65.25	40.47	**50.71**	69.19
1 kW	Capital Cost	US$/kW	570	**680**	790	500	**625**	750	470	**620**	770
	Fixed O&M	US¢/kWh	–	**–**	–	–	**–**	–	–	**–**	–
	Variable O&M	US¢/kWh	2.40	**3.00**	3.60	2.39	**3.00**	3.60	2.38	**3.00**	3.60
	Fuel	US¢/kWh	38.50	**44.38**	52.32	32.95	**40.73**	53.02	32.88	**41.20**	56.21
100 kW	Capital Cost	US$/kW	550	**640**	730	480	**595**	700	460	**590**	720
	Fixed O&M	US¢/kWh	1.60	**2.00**	2.40	1.60	**2.00**	2.40	1.60	**2.00**	2.40
	Variable O&M	US¢/kWh	2.40	**3.00**	3.60	2.39	**3.00**	3.60	2.38	**3.00**	3.60
	Fuel	US¢/kWh	11.53	**14.04**	17.82	10.01	**13.09**	18.37	9.98	**13.27**	19.60
5 MW	Capital Cost	US$/kW	520	**600**	680	460	**555**	650	440	**550**	660
	Fixed O&M	US¢/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	US¢/kWh	2.00	**2.50**	3.00	1.99	**2.50**	3.00	1.98	**2.50**	3.00
	Fuel	US¢/kWh	3.64	**4.84**	6.64	2.92	**4.39**	6.90	2.91	**44.8**	7.49

(continued...)

(...Table A22.1 continued)

Microturbine

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
150 W	Capital Cost	US$/kW	830	**960**	1,090	620	**780**	910	500	**680**	810
	Fixed O&M	US¢/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	US¢/kWh	2.00	**2.50**	3.00	1.83	**2.50**	3.00	1.69	**2.50**	3.00
	Fuel	US¢/kWh	25.11	**26.86**	29.40	23.60	**26.00**	29.63	23.46	**26.15**	30.62

Fuel Cells

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
1200 kW	Capital Cost	US$/kW	3,150	**3,640**	4,120	2,190	**2,820**	3,260	1,470	**2,100**	2,450
	Fixed O&M	US¢/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	US¢/kWh	3.60	**4.50**	5.40	3.15	**4.50**	5.40	2.69	**4.50**	5.40
	Fuel	US¢/kWh	15.22	**16.28**	17.82	14.30	**15.76**	17.96	14.22	**15.85**	18.56
5 MW	Capital Cost	US$/kW	3,150	**3,630**	4,110	2,180	**2,820**	3,260	1,470	**2,100**	2,450
	Fixed O&M	US¢/kWh	0.80	**1.00**	1.20	0.80	**1.00**	1.20	0.80	**1.00**	1.20
	Variable O&M	US¢/kWh	3.60	**4.50**	5.40	3.15	**4.50**	5.40	2.69	**4.50**	5.40
	Fuel	US¢/kWh	3.37	**4.18**	5.34	2.67	**3.78**	5.45	2.61	**3.85**	5.90

(continued...)

(...Table A22.1 continued)

Combustion Turbine

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
150 MW	Capital Cost	US$/kW	430	**490**	550	360	**430**	490	340	**420**	490
	Fixed O&M	US¢/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.24	**0.30**	0.36
	Variable O&M	US¢/kWh	0.80	**1.00**	1.20	0.78	**1.00**	1.20	0.77	**1.00**	1.20
	Fuel	US¢/kWh	4.89	**6.12**	7.95	3.93	**5.57**	8.14	3.84	**5.68**	8.80

Combined Cycle

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 W	Capital Cost	US$/kW	570	**650**	720	490	**580**	660	450	**560**	650
	Fixed O&M	US¢/kWh	0.08	**0.10**	0.12	0.08	**0.10**	0.12	0.08	**0.10**	0.12
	Variable O&M	US¢/kWh	0.32	**0.40**	0.48	0.31	**0.40**	0.48	0.31	**0.40**	0.48
	Fuel	US¢/kWh	3.29	**4.12**	5.35	2.64	**3.75**	5.48	2.59	**3.83**	5.93

(continued...)

(...*Table A22.1 continued*)

Coal Steam

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 MW	Capital Cost	US$/kW	1,080	**1,190**	1,310	960	**1,080**	1,220	910	**1,060**	1,200
	Fixed O&M	US¢/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	US¢/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
	Fuel	US¢/kWh	1.67	**1.97**	2.50	1.54	**1.87**	2.51	1.54	**1.90**	2.63
500 MW Sub Cr	Capital Cost	US$/kW	1,030	**1,140**	1,250	910	**1,030**	1,150	870	**1,010**	1,140
Fixed O&M		US¢/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
Variable O&M		US¢/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
Fuel	US¢/kWh	1.62	**1.92**	2.44	1.50	**1.82**	2.45	1.50	**1.85**	2.57	
500 MW SC	Capital Cost	US$/kW	1,070	**1,180**	1,290	950	**1,070**	1,200	900	**1,050**	1,190
Fixed O&M		US¢/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
Variable O&M		US¢/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.28	**0.36**	0.43
Fuel	US¢/kWh	1.55	**1.83**	2.32	1.43	**1.73**	2.33	1.43	**1.76**	2.44	
500 MW USC	Capital Cost	US$/kW	1,150	**1,260**	1,370	1,020	**1,140**	1,250	960	**1,100**	1,230
	Fixed O&M	US¢/kWh	0.30	**0.38**	0.46	0.30	**0.38**	0.46	0.30	**0.38**	0.46
	Variable O&M	US¢/kWh	0.29	**0.36**	0.43	0.28	**0.36**	0.43	0.27	**0.36**	0.43
	Fuel	US¢/kWh	1.44	**1.70**	2.16	1.33	**1.61**	2.17	1.33	**1.64**	2.27

(*continued...*)

(...Table A22.1 continued)

Coal IGCC

Capacity	Contents	Units	2005			2010			2015		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 MW	Capital Cost	US$/kW	1,450	**1,610**	1,770	1,200	**1,390**	1,550	1,070	**1,280**	1,440
	Fixed O&M	US¢/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	US¢/kWh	0.17	**0.21**	0.25	0.16	**0.21**	0.25	0.15	**0.21**	0.25
	Fuel	US¢/kWh	1.51	**1.79**	2.27	1.40	**1.70**	2.28	1.40	**1,72**	2.39
500 MW	Capital Cost	US$/kW	1,350	**1,500**	1,650	1,130	**1,300**	1,450	1,000	**1,190**	1,340
	Fixed O&M	US¢/kWh	0.72	**0.90**	1.08	0.72	**0.90**	1.08	0.72	**0.90**	1.08
	Variable O&M	US¢/kWh	0.17	**0.21**	0.25	0.16	**0.21**	0.25	0.15	**0.21**	0.25
	Fuel	US¢/kWh	1.47	**1.73**	2.20	1.36	**1.64**	2.21	1.36	**1.67**	2.32

(continued...)

(...Table A22.1 continued)

Coal AFBC

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 MW	Capital Cost	US$/kW	1,060	**1,180**	1,300	940	**1,070**	1,210	880	**1,040**	1,180
	Fixed O&M	US¢/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	US¢/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.26	**0.34**	0.41
	Fuel	US¢/kWh	1.32	**1.52**	2.00	1.31	**1.56**	2.20	1.33	**1.58**	2.24
500 MW	Capital Cost	US$/kW	1,010	**1,120**	1,230	900	**1,020**	1,140	840	**990**	1,120
	Fixed O&M	US¢/kWh	0.40	**0.50**	0.60	0.40	**0.50**	0.60	0.40	**0.50**	0.60
	Variable O&M	US¢/kWh	0.27	**0.34**	0.41	0.27	**0.34**	0.41	0.26	**0.34**	0.41
	Fuel	US¢/kWh	1.29	**1.49**	1.96	1.26	**1.52**	2.15	1.30	**1.54**	2.19

Oil Steam

Capacity	*Contents*	*Units*	*2005*			*2010*			*2015*		
			Minimum	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*	*Minimum*	***Probable***	*Maximum*
300 MW	Capital Cost	US$/kW	780	**880**	980	700	**810**	920	670	**800**	920
	Fixed O&M	US¢/kWh	0.28	**0.35**	0.42	0.28	**0.35**	0.42	0.28	**0.35**	0.42
	Variable O&M	US¢/kWh	0.24	**0.30**	0.36	0.24	**0.30**	0.36	0.24	**0.30**	0.36
	Fuel	US¢/kWh	3.95	**5.32**	7.52	3.23	**4.88**	7.84	3.22	**4.97**	8.49

Note: "–" means no cost needed.

Annex 23

High/Low Charts for Power Generation Capital and Generating Costs

Figure A23.1: Off-grid Forecast Capital Cost

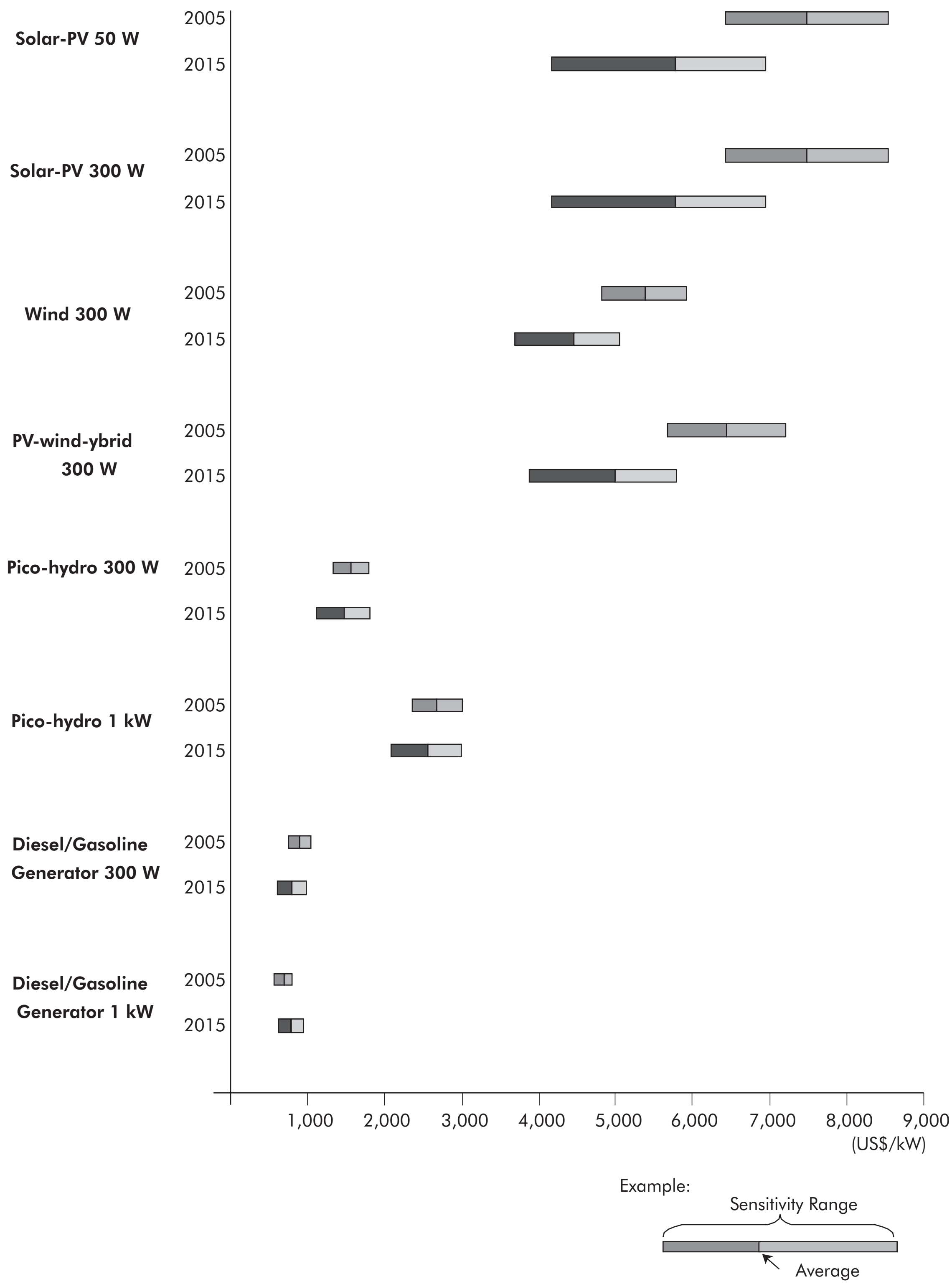


Figure A23.2: Mini-grid Forecast Capital Cost

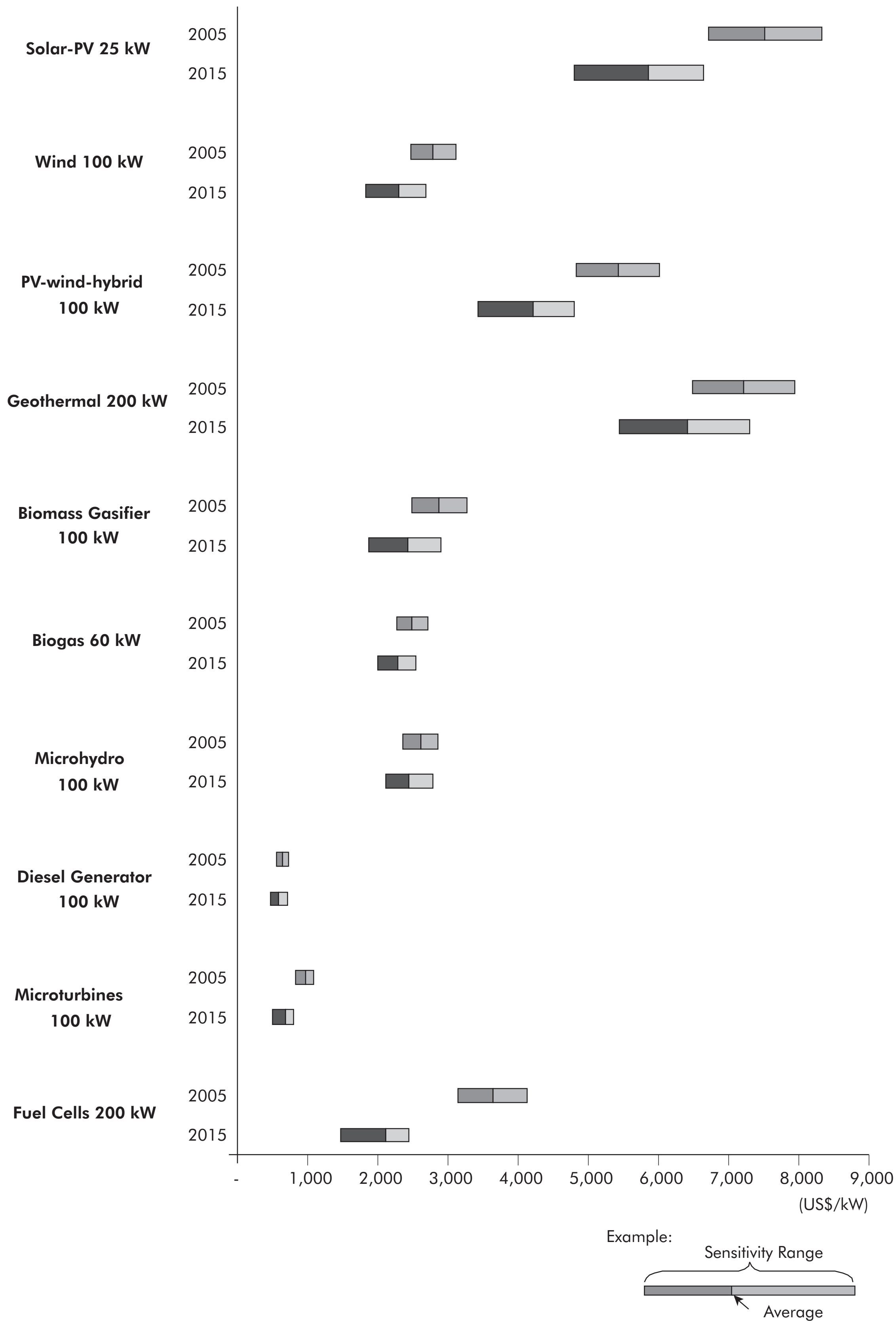


Figure A23.3: Grid-connected (5-50 MW) Forecast Capital Cost

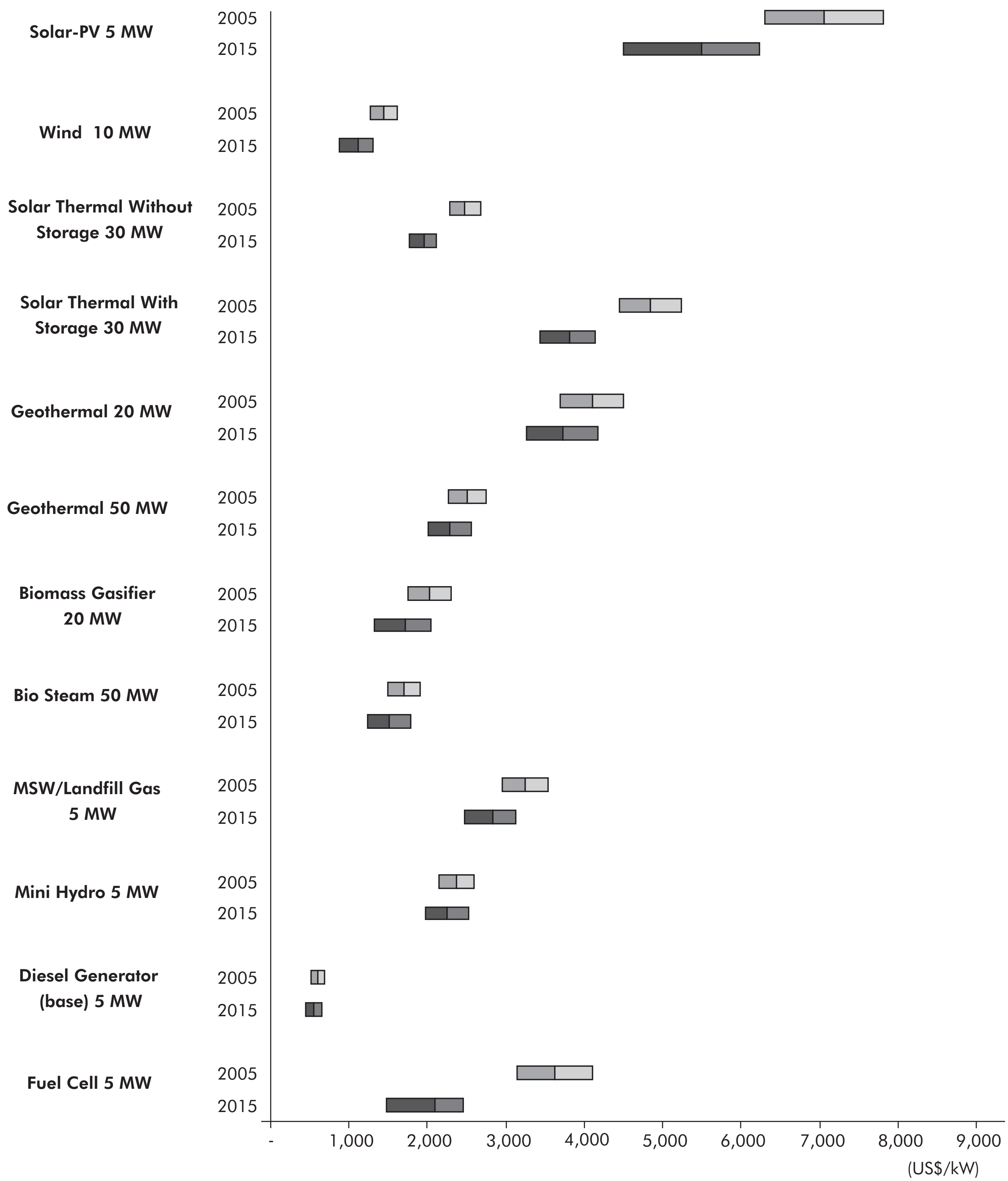


Figure A23.4: Grid-connected (50-300 MW) Forecast Capital Cost

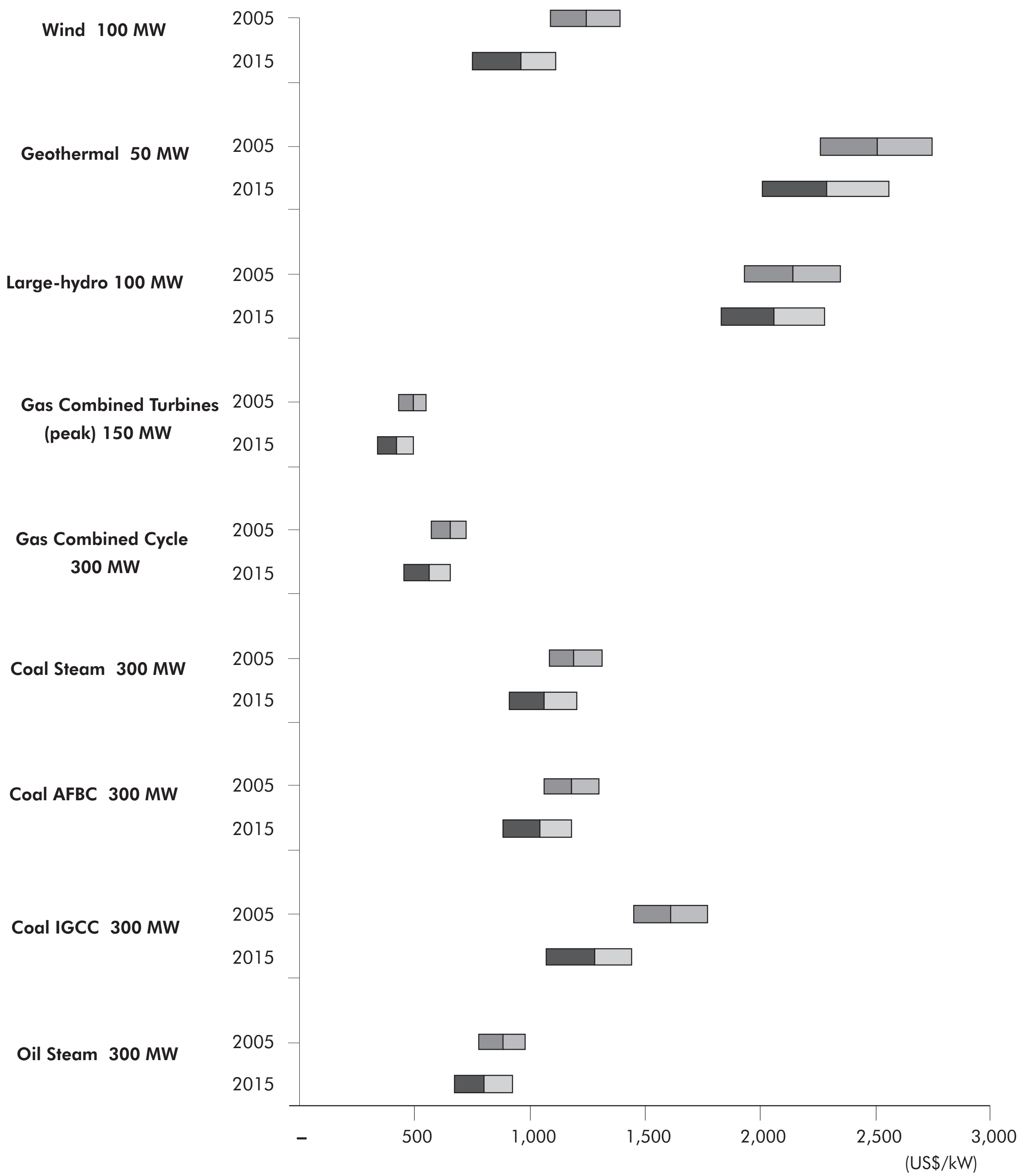


Figure A23.5: Off-grid Forecast Generating Cost

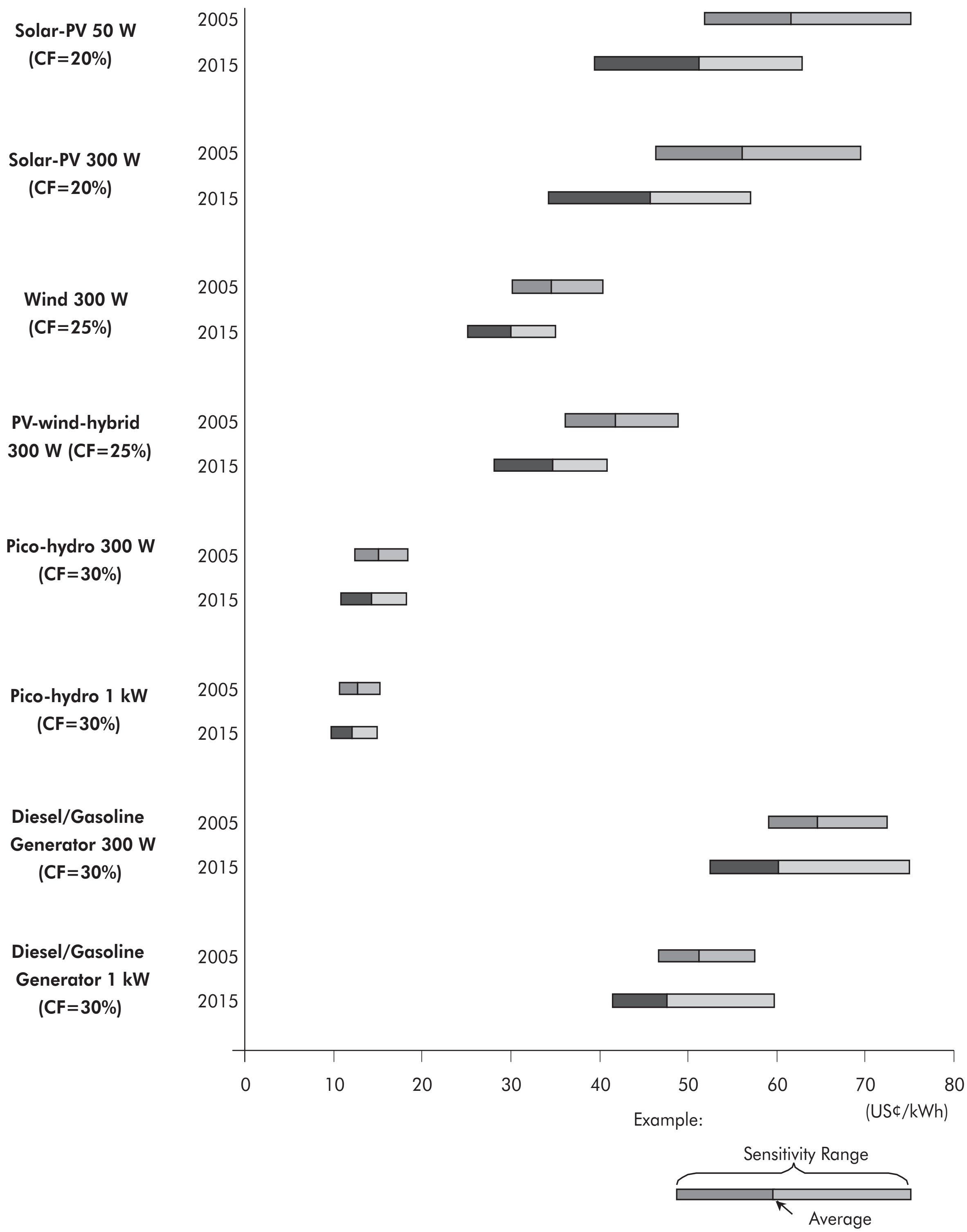


Figure A23.6: Mini-grid Forecast Generating Cost

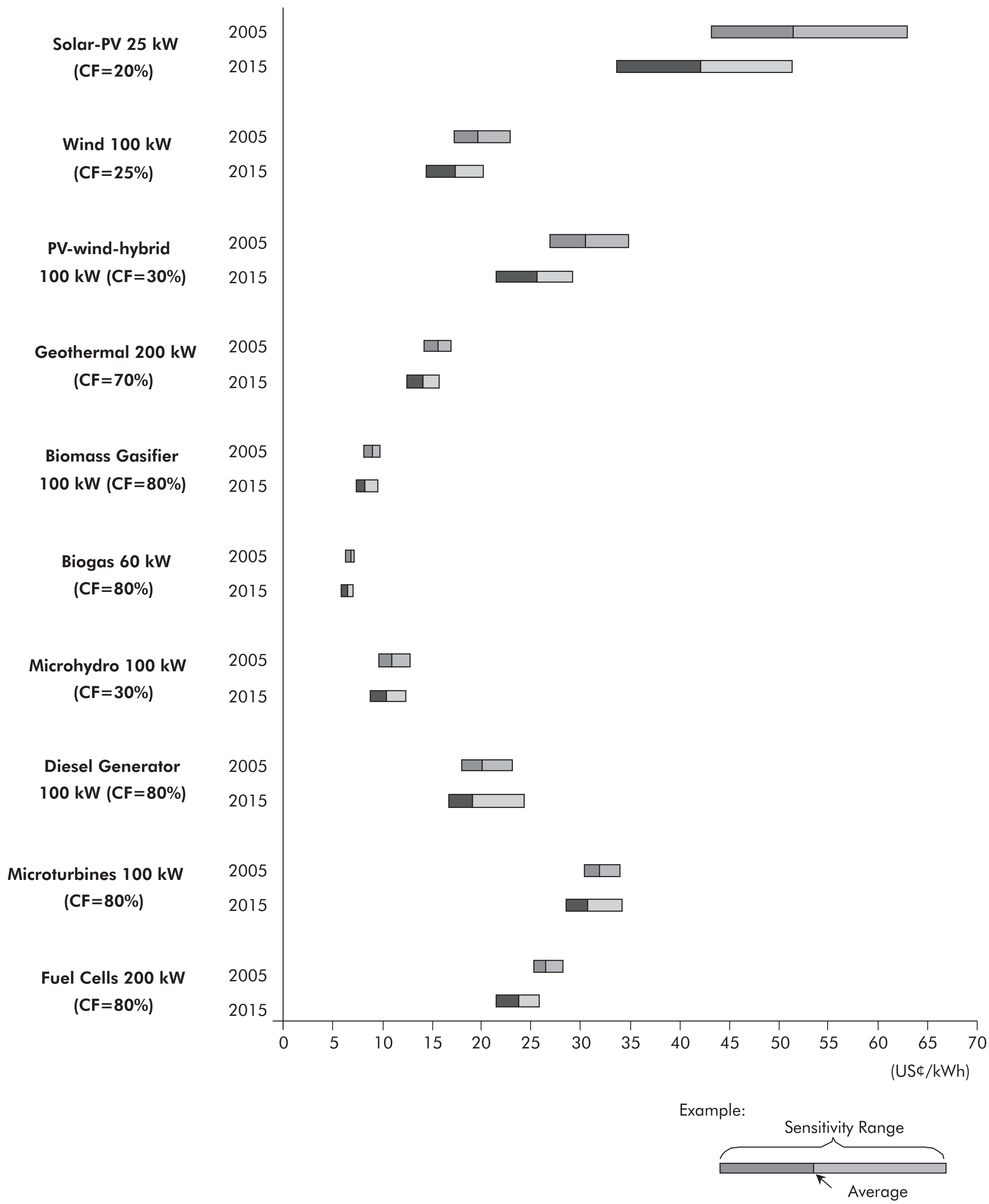


Figure A23.7: Grid-connected (5-50 MW) Forecast Generating Cost

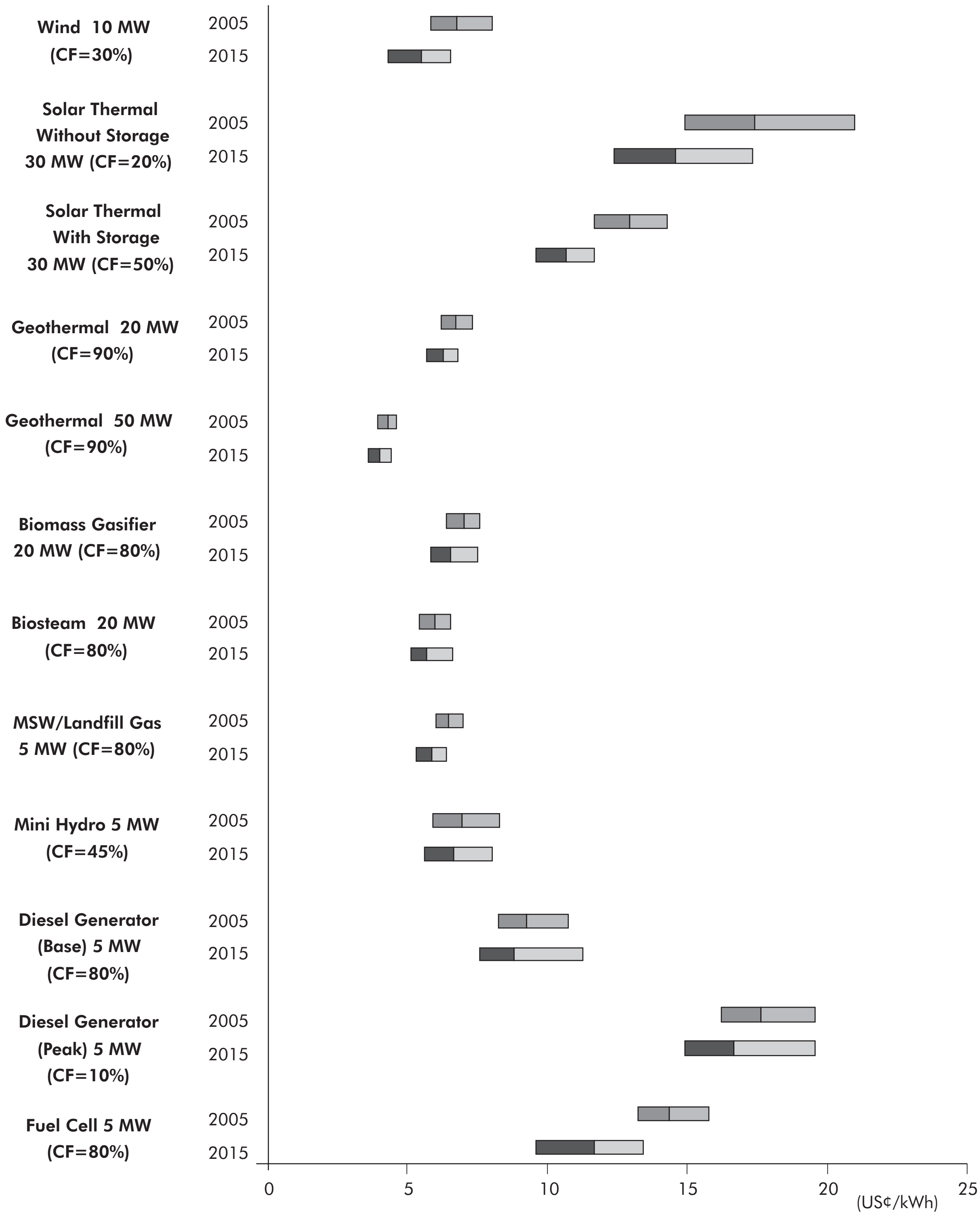


Figure A23.8: Grid-connected (50-300 MW) Forecast Generating Cost

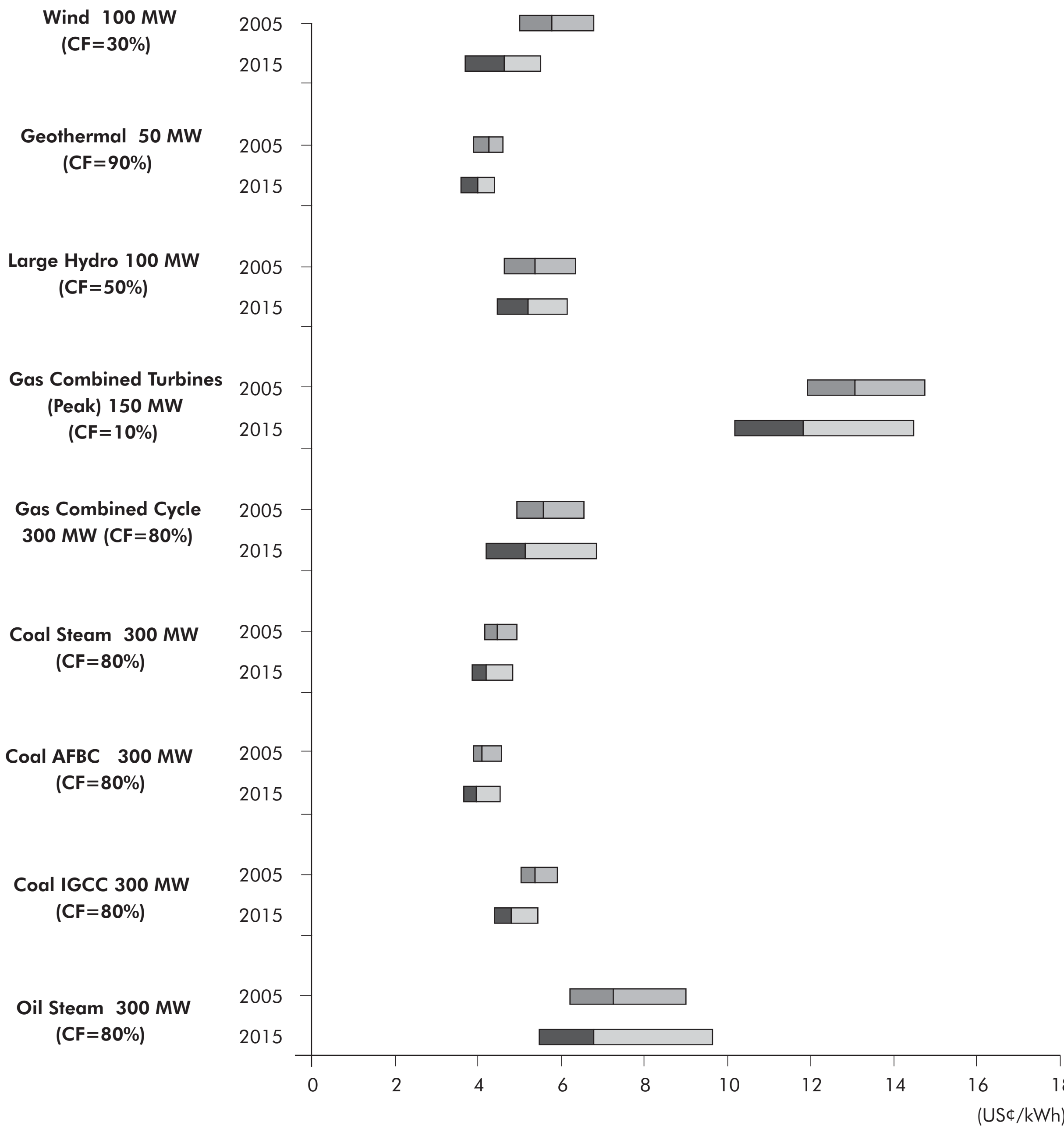
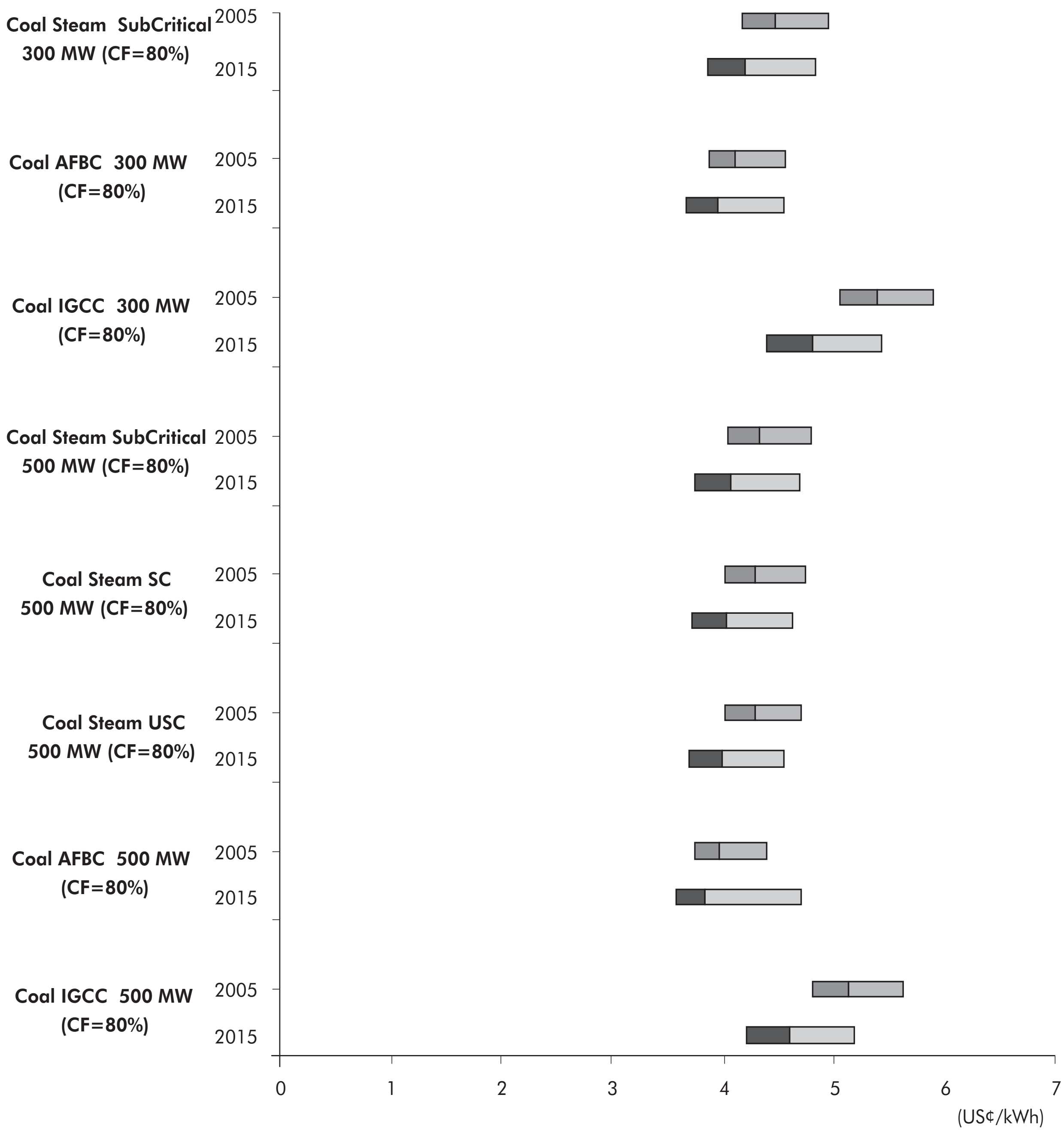


Figure A23.9: Coal-fired (300-500 MW) Forecast Generating Cost



Annex 24

Data Table for Generation Capital Cost and Generating Costs

Table A24.1: Generation Capital Cost and Generating Costs

Generating-types	*Capacity*	2005 *Min*	2005 ***Probable***	2005 *Max*	2010 *Min*	2010 ***Probable***	2010 *Max*	2025 *Min*	2025 ***Probable***	2025 *Max*
Capital Costs										
Solar-PV	50 W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
	300 W	6,430	7,480	8,540	5,120	6,500	7,610	4,160	5,780	6,950
	25 kW	6,710	7,510	8,320	5,630	6,590	7,380	4,800	5,860	6,640
	5 MW	6,310	7,060	7,810	5,280	6,190	6,930	4,500	5,500	6,235
Wind	300 W	4,820	5,370	5,930	4,160	4,850	5,430	3,700	4,450	5,050
	100 kW	2,460	2,780	3,100	2,090	2,500	2,850	1,830	2,300	2,670
	10 MW	1,270	1,440	1,610	1,040	1,260	1,440	870	1,120	1,300
	100 MW	1,090	1,240	1,390	890	1,080	1,230	750	960	1,110
PV-wind Hybrids	300 W	5,670	6,440	7,210	4,650	5,630	6,440	3,880	5,000	5,800
	100 kW	4,830	5,420	6,020	4,030	4,750	5,340	3,420	4,220	4,800
Solar Thermal (without thermal storage)	30 MW	2,290	2,480	2,680	1,990	2,200	2,380	1,770	1,960	2,120
Solar Thermal (with thermal storage)	30 MW	4,450	4,850	5,240	3,880	4,300	4,660	3,430	3,820	4,140
Geothermal	200 kW (Binary)	6,480	7,220	7,950	5,760	6,580	7,360	5,450	6,410	7,300
	20 MW (Binary)	3,690	4,100	4,500	3,400	3,830	4,240	3,270	3,730	4,170
	50 MW (Flash)	2,260	2,510	2,750	2,090	2,350	2,600	2,010	2,290	2,560
Biomass Gasifier	100 kW	2,490	2,880	3,260	2,090	2,560	2,980	1,870	2,430	2,900
	20 MW	1,760	2,030	2,300	1,480	1,810	2,100	1,320	1,710	2,040
Biomass Steam	50 MW	1,500	1,700	1,910	1,310	1,550	1,770	1,240	1,520	1,780
MSW/Landfill Gas	5 MW	2,960	3,250	3,540	2,660	2,980	3,270	2,480	2,830	3,130
Biogas	60 kW	2,260	2,490	2,720	2,080	2,330	2,570	2,000	2,280	2,540
Pico/Micro Hydro	300 W	1,320	1,560	1,800	1,190	1,485	1,770	1,110	1,470	1,810
	1 kW	2,360	2,680	3,000	2,190	2,575	2,950	2,090	2,550	2,990
	100 kW	2,350	2,600	2,860	2,180	2,470	2,750	2,110	2,450	2,780
Mini-hydro	5 MW	2,140	2,370	2,600	2,030	2,280	2,520	1,970	2,250	2,520
Large-hydro	100 MW	1,930	2,140	2,350	1,860	2,080	2,290	1,830	2,060	2,280
Pumped Storage Hydro	150 MW	2,860	3,170	3,480	2,760	3,080	3,400	2,710	3,050	3,380
Diesel/Gasoline Generator	300 W	750	890	1,030	650	810	970	600	800	980
	1 kW	570	680	790	500	625	750	470	620	770
	100 kW	550	640	730	480	595	700	460	590	720
	5 MW (Base Load)	520	600	680	460	555	650	440	550	660
	5 MW (Peak Load)	520	600	680	460	555	650	440	550	660

(continued...)

(...Table A24.1 continued)

Generating-types	*Capacity*	*2005*			*2010*			*2025*		
		Min	***Probable***	*Max*	*Min*	***Probable***	*Max*	*Min*	***Probable***	*Max*
Microturbines	150 kW	830	960	1,090	620	780	910	500	680	810
Fuel Cells	200 kW	3,150	3,640	4,120	2,190	2,820	3,260	1,470	2,100	2,450
	5 MW	3,150	3,630	4,110	2,180	2,820	3,260	1,470	2,100	2,450
Oil/Gas Combined Turbines	150 MW (1,100C class)	430	490	550	360	430	490	340	420	490
Oil/Gas Combined Cycle	300 MW (1,300C class)	570	650	720	490	580	660	450	560	650
Coal Steam with FGD & SCR (SubCritical)	300 MW	1,080	1,190	1,310	960	1,080	1,220	910	1,060	1,200
Coal Steam with FGD & SCR (SubCritical)	500 MW	1,030	1,140	1,250	910	1,030	1,150	870	1,010	1,140
Coal Steam with FGD & SCR (SC)	500 MW	1,070	1,180	1,290	950	1,070	1,200	900	1,050	1,190
Coal AFB Without FGD & SCR (USC)	500 MW	1,150	1,260	1,370	1,020	1,140	1,250	960	1,100	1,230
Coal AFB Without FGD & SCR	300 MW	1,060	1,180	1,300	940	1,070	1,210	880	1,040	1,180
	500 MW	1,010	1,120	1,230	900	1,020	1,140	840	990	1,120
Coal IGCC Without FGD & SCR	300 MW	1,450	1,610	1,770	1,200	1,390	1,550	1,070	1,280	1,440
	500 MW	1,350	1,500	1,650	1,130	1,300	1,450	1,000	1,190	1,340
Oil-steam	300 MW	780	880	980	700	810	920	670	800	920
Generating Costs										
Solar-PV	50 W	51.8	61.6	75.1	44.9	55.6	67.7	39.4	51.2	62.8
	300 W	46.4	56.1	69.5	39.6	50.1	62.1	34.2	45.7	57.0
	25 kW	43.1	51.4	63.0	37.7	46.2	56.6	33.6	42.0	51.3
	5 MW	33.7	41.6	52.6	28.9	36.6	46.3	25.0	32.7	41.4
Wind	300 W	30.1	34.6	40.4	27.3	32.0	37.3	25.2	30.1	35.1
	100 kW	17.2	19.7	22.9	15.6	18.3	21.3	14.4	17.4	20.2
	10 MW	5.8	6.8	8.0	5.0	6.0	7.1	4.3	5.5	6.5
	100 MW	5.0	5.8	6.8	4.2	5.1	6.1	3.7	4.7	5.5
PV-wind Hybrids	300 W	36.1	41.8	48.9	31.6	37.8	44.5	28.1	34.8	40.9
	100 kW	26.8	30.5	34.8	23.8	27.8	31.7	21.4	25.6	29.1
Solar Thermal (Without thermal storage)	30 MW	14.9	17.4	21.0	13.5	15.9	19.0	12.4	14.5	17.3
Solar Thermal (With thermal storage)	30 MW	11.7	12.9	14.3	10.5	11.7	12.9	9.6	10.7	11.7
Geothermal	200 kW (Binary)	14.2	15.6	16.9	13.0	14.5	15.9	12.5	14.2	15.7
	20 MW (Binary)	6.2	6.7	7.3	5.8	6.4	6.9	5.7	6.3	6.8
	50 MW (Flash)	3.9	4.3	4.6	3.7	4.1	4.4	3.6	4	4.4

(continued...)

(...Table A24.1 continued)

Generating-types	*Capacity*	*2005*			*2010*			*2025*		
		Min	***Probable***	*Max*	*Min*	***Probable***	*Max*	*Min*	***Probable***	*Max*
Biomass Gasifier	100 kW	8.2	9.0	9.7	7.6	8.5	9.4	7.3	8.3	9.5
	20 MW	6.4	7.0	7.6	6.0	6.7	7.5	5.8	6.5	7.5
Biomass Steam	50 MW	5.4	6.0	6.5	5.2	5.7	6.4	5.1	5.7	6.6
MSW/Landfill Gas	5 MW	6.0	6.5	7.0	5.6	6.1	6.6	5.3	5.9	6.4
Biogas	60 kW	6.3	6.8	7.2	6.0	6.5	7.1	5.9	6.5	7.1
Pico/Micro Hydro	300 W	12.4	15.1	18.4	11.4	14.5	18.0	10.8	14.3	18.2
	1 kW	10.7	12.7	15.2	10.1	12.3	14.8	9.7	12.1	14.9
	100 kW	9.6	11.0	12.8	9.1	10.5	12.3	8.9	10.5	12.3
Mini-hydro	5 MW	5.9	6.9	8.3	5.7	6.7	8.1	5.6	6.6	8.0
Large-hydro	100 MW	4.6	5.4	6.3	4.5	5.2	6.2	4.5	5.2	6.2
Pumped Storage Hydro	150 MW	31.4	34.7	38.1	30.3	33.8	37.2	29.9	33.4	36.9
Diesel/Gasoline Generator	300 W	59.0	64.6	72.5	52.4	59.7	71.8	52.5	60.2	75.0
	1 kW	46.7	51.2	57.6	41.4	47.3	57.1	41.5	47.7	59.7
	100 kW	18.1	20.0	23.1	16.6	19.0	23.3	16.7	19.2	24.3
	5 MW (Base-Load)	8.3	9.3	10.8	7.6	8.7	10.8	7.6	8.8	11.3
	5 MW (Peak-Load)	16.2	17.7	19.6	15.0	16.7	19.1	14.9	16.7	19.6
Microturbines	150 kW	30.4	31.8	33.9	28.8	30.7	33.5	28.5	30.7	34.2
Fuel Cells	200 kW	25.2	26.5	28.2	22.8	24.7	26.6	21.5	23.7	25.8
	5 MW	13.2	14.4	15.8	11.0	12.7	14.4	9.6	11.7	13.4
Oil/Gas Combined Turbines	150 MW (1,100C class)	11.9	13.1	14.7	10.4	11.8	14.0	10.2	11.8	14.5
Oil/Gas Combined Cycle	300 MW (1,300C class)	4.94	5.57	6.55	4.26	5.10	6.47	4.21	5.14	6.85
Coal Steam With FGD & SCR (SubCritical)	300 MW	4.18	4.47	4.95	3.91	4.20	4.76	3.86	4.20	4.84
Coal Steam With FGD & SCR (SubCritical)	500 MW	4.05	4.33	4.79	3.77	4.07	4.62	3.74	4.06	4.69
Coal Steam With FGD & SCR (SC)	500 MW	4.02	4.29	4.74	3.74	4.04	4.56	3.72	4.03	4.63
Coal Steam With FGD & SCR (USC)	500 MW	4.02	4.29	4.71	3.74	4.02	4.51	3.69	3.99	4.55
Coal AFB Without FGD & SCR	300 MW	3.88	4.11	4.56	3.72	3.98	4.55	3.67	3.96	4.55
	500 MW	3.75	3.97	4.40	3.61	3.86	4.42	3.58	3.83	4.71
Coal IGCC Without FGD & SCR	300 MW	5.05	5.39	5.90	4.58	4.95	5.52	4.40	4.81	5.43
	500 MW	4.81	5.14	5.62	4.38	4.74	5.28	4.21	4.60	5.19
Oil-steam	300 MW	6.21	7.24	9.00	5.50	6.70	9.08	5.49	6.78	9.63

Annex 25

Environmental Externalities

This section reviews methods for estimating environmental externality (damage) costs and provides examples of how such costs could be incorporated in technology selection. Literature references are provided throughout the document, so the reader can obtain more information and guidance on how to carry out an environmental externality assessment, as it relates to a specific project.

Methodology

The concept of "environmental externalities" is based on the following principles:

- *Power Production costs* usually include all the costs incurred by the project entity (owner), assuming that market prices are not distorted. Key parameters which bound the calculation of production costs are: the *project boundary,* which is usually the physical boundary of the project and includes all the associated costs (expenses) to build and operate the facility; and the *project time horizon,* which is usually the operating life of the facility, as defined by the "design life" as well as any operating permits.
- *Social costs* are the costs incurred due to the project by society. Social costs are usually higher than production costs because:
  - The project boundary is wider; leading to costs incurred outside the project boundaries (water pollution, air pollution, effects on other economic activities) but not factored into power production costs; and
  - The project may continue to have impacts on the environment or other economic activities long after the established project time horizon.
- The difference between social and production costs are the externality costs. The microeconomics literature and most project evaluation guidelines state that any comprehensive economic analysis should include externalities.

The methodology for estimating a project's externality costs involves five steps:

- Determine the pollutant loads (for example, air and water emissions);
- Estimate impact on environmental quality;
- Assess the level of exposure;
- Estimate the impacts on the environment and health; and
- Estimate the monetary value of impacts.

Determine pollutant loads

In this step, the amount of pollution caused by the project is estimated, usually in tons per year. However, certain pollutants may have different impacts at different times. For example,

NO_x emissions may need to be estimated on an hourly rate (tons/day or tons/hr) during peak ozone times. All pollutants should be estimated, including air emissions (SO_2, NO_x, CO and CO_2), water effluents, solid wastes, etc. The main factors affecting the amount of pollutants released include:

- Size of facility;
- Fuel composition;
- Efficiency of the power plant,[67] which, in turn, is affected by fuel characteristics and plant design;
- Environmental control equipment employed;
- Utilization (capacity) factor; and
- Environmental regulations, which may limit the rate of the pollutant (Kg/MWh or Kg/fuel input) and/or the total amount (tons/yr).

Estimate Impact on Environmental Quality[68]

In this step, the impact of the pollutants on environmental quality is estimated. Over time, pollutants will gradually increase the atmospheric and water-borne loading of chemical compounds. Determination of this environmental quality impact for a given project is very site-specific and involves tools such as pollution transport, transformation and dispersion and deposition models. Key factors to take into account include:

- Topography of the plant;
- Prevailing winds and climatic factors, especially the direction and strength of wind and water flow;
- Stack (chimney) height; and
- Characteristics of the pollutants, for example, PM can affect the concentration of the air in the proximity to the project, while gaseous pollutants (for example, SO_2, $NO_{x,}$) are dispersed over a wide radius.

The measure of environmental quality is usually driven by environmental regulations. For example, regulations limit the average annual concentration of SO_2; therefore, dispersion

[67] We will refer to "power plant" or "plant" because the focus of this report is on power plants; however, the same environmental externality methodology could be applied for other industrial facilities.
[68] The World Bank's Pollution Prevention and Abatement Handbook 1998 provides a comprehensive guide of the dispersion (page 82) and water quality models (page 101), which are available and commonly used to perform this step.

modeling will assess whether the annual emissions from the project will increase the ambient SO_2 concentration above allowable levels.

Environmental quality also involves impacts on habitats, recreation areas and aesthetics. While these are difficult to quantify, it is important to note the potential impacts and take them into account in a semi-quantitative or qualitative manner.

Assess the Level of Exposure

Environmental quality degradation affects people, materials, wildlife and vegetation. This step assesses the level of this exposure. Key factors to be considered include:

- Density of receptors as a function of distance from the plant;
- Age of population;
- Vulnerability to the pollutant; and
- Local economic activity (possibly represented by GDP), agricultural production, and so on, and so forth.

Estimate of the Environmental and Health Effects (Dose-Response Relationship)

This step estimates the impacts on people, plants, animals and materials of exposure to increased pollutant concentrations. Impacts include: human mortality and morbidity, loss of habitat, agricultural impacts, materials and structures corrosion, and aesthetic impacts. These responses are usually estimated through a dose-response relationship (DRR) that relates the severity or the probability of a response to the amount of pollutant the "receptor" is exposed to. DDRs are statistical relationships using historical data from the same or similar locations. Epidemiologic studies or laboratory studies may be needed to determine these relationships.[69]

Valuation (Estimating the Monetary Equivalent) of Environmental and Health Impacts)

Valuation of health and environmental impacts is the most challenging step, because it involves subjective judgment of the value of human life, cost of illness (medical costs), value

[69] *The World Bank's Pollution Prevention and Abatement Handbook 1998 (pages 58 and 63) provides a comprehensive DRR determination.*

of degraded scenery, and so on, and so forth. Many different approaches are used to determine the value of these impacts including:

- The *Human capital approach,* which places a value on premature death based on a person's future earning capacity;
- The *Cost of illness approach,* similar to the human capital approach, which considers the lost economic output due to inability to work plus out-of-pocket costs (for example, medical expenses);
- The *Preventive expenditures approach*, which infers the amount people are willing to pay to reduce health risks;
- The *Willingness-to-pay approach*, which is based on what people are willing to pay to reduce health risks they may face;
- The *Wage differential approach,* which uses differences in wage rates to measure the compensation people require for (perceived) differences in the probability of dying or falling ill from increased exposure to a pollutant; and
- The *Contingent valuation approach*, which uses survey information to determine people's willingness to pay to reduce exposure to pollution.

Suitability of the Methodology to Developing Countries

The methodology described above is universal and as such suitable for developing countries. The issues associated with the methodology relate to the uncertainty and subjectivity of some analyses (especially Steps 2, 4 and 5), but these issues are faced in all countries. Developing countries are likely to find it more difficult to obtain certain information required for the analysis, such as data on air quality, health statistics of the population and even economic activity. Nevertheless, the methodology applies and many such studies have been carried out.[70] Also, while there are many issues associated with the methodology, applying it raises the awareness level of the impacts from environmental pollution (cause-and-effect relationships) and has an overall positive effect on all stakeholders.

There have been numerous analytic studies of environmental externalities in the United States and elsewhere. These various studies have explicitly or implicitly placed a valuation on environmental emissions (Table A25.1). These values should be taken as indicative, as each location and setting may result in significantly different numerical results. Furthermore,

[70] *See, for example: Asian Development Bank (1996): "Economic Evaluation of Environmental Impacts," Asian Development Bank; Bates, R., et al (1994): "Alternative policies for the control of air pollution in Poland," the World Bank Environment Paper No. 7; Bennagen, E.C. (1995): "Philippines environmental and natural resources accounting project/ANRAP sectoral studies on pollution," USAID; Cropper, M.L., Simon, N.B., Alberini, A., and Sharma, O.K. (1997): "The Health Effects of Air Pollution in Delhi, India," Policy Research Working Paper 1860, the World Bank.*

externality values vary significantly even for similar locations, indicating the subjectivity and influence of key assumptions. For example, SO_2 externalities in the various states of the United States vary from US$150 to 4,486/ton, even though the setting from state to state is very similar (for example, Massachusetts and New York). Similarly, NO_x varies from US$850 to 9,120/ton, particulates from US$333 to 4,608/ton and CO_2 from US$1 to 25/ton. Nevertheless, these estimates define a range which is presumably acceptable. This range can become narrower by considering that some of these pollutants have become commodities and are traded. Considering that the externalities and the emission control costs are expected to be above the traded values, the lower limit of the externality range can be adjusted accordingly. For example, in the United States, NOx values in the last two years (2002-04) have ranged from US$2,500 to 5,000/ton. So, the externality range defined in Table A25.1 (US$850-9,120/ton) can be adjusted to US$2,500-9,120/ton.

Note: The externalities in developing countries are an order of magnitude lower than in OECD countries. This may change as income per capita (and GDP) of developing countries increases, but for the time being, this significant difference will likely continue.

With regard to CO_2, many studies have estimated the global damage in the US$3 to 20/ton CO_2 range; IPCCC puts the damage costs in the US$1.4 to 28.6/ton CO_2 (US$5 to 105/ton of carbon). Of course, recent trading of greenhouse gas emission reductions (ranging from US$3 to 15/ton of CO_2) can be taken as another indicator.

Table A25.1: Indicative Results of Environmental Externality Studies

Organization	*Location*	*SO_2*	*NO_x*	*Particulates*	*CO_2*
Pace University[1]	USA (general)	4,474	1,807	2,623	15
DOE[2]	USA/California	4,486	9,120	4,608	9
DOE[2]	USA/Massachusetts	1,700	7,200	4,400	24
DOE[2]	USA/Minnesota	150	850	1,274	9.8
DOE[2]	USA/Nevada	1,716	7,480	4,598	24
DOE[2]	USA/New York	1,437	1,897	333	1
DOE[2]	USA/Oregon	0	3,500	3,000	25
The World Bank[3]	Philippines	95	71	67	NA
The World Bank[4]	China/Shanghai	390	454	1,903	NA
The World Bank[4]	China/Henan	217	252	940	NA
The World Bank[4]	China/Hunan (2000)	364	201	801	NA

Sources:
1 *Pace University, "Environmental Costs of Electricity," Ocean Publications (1990).*
2 *DOE/EIA-0598, "Electricity Generation and Environmental Externalities: Case Studies" (1995).*
3 *The World Bank/Assessment of the value of Malampaya natural gas for the power sector of the Philippines (1996).*
4 *The World Bank/Technology Assessment of Clean Coal Technologies for China/Volume III (2001).*
Note: NA = Not applicable.

Examples of Environmental Externality Studies

During the period 1999-2001, the World Bank carried out a number of studies in China focusing on clean coal technologies, environmental controls and integration of environmental aspects in power system planning.[71] Three case studies were carried out in the city of Shanghai and the provinces of Henan and Hunan. The cases of Shanghai and Henan province employ a top-down approach; mainly due to lack of data and resources to carry out a very comprehensive assessment, it was decided to utilize values from other countries (for example, State of New York, USA) and adjust them for the key characteristics of each site (Shanghai and Henan province). In the case of Hunan province, a comprehensive assessment was carried out including dispersion of pollutants and health impacts. Externality values developed for the State of New York[72] were used as a basis for the study. First, the New York values were adjusted for income per capita differences.[73] The values obtained were multiplied by the number of affected individuals as a function of the distance from a presumed power plant (Table A25.2). For all pollutants (TSP, SO_2 or NO_x), the environmental damage is approximately twice in Shanghai than in Henan, mainly because of higher population density.

Table A25.2: Externality Values for Two Chinese Cities[74] (US$ 1996/ton)

	Shanghai	*Henan*
TSP/PM10	1903	940
SO_2	390	217
NO_x	454	252

A second case study applied a Dispersion Modeling and Damage Cost Estimation Approach to Hunan Province. The externality cost of each pollutant (SO_2, NO_x and TSP) was estimated independently using Dispersion Modeling and Damage Cost Valuation Approach. For SO_2, the entire province was taken into account, and three major types of damages were considered: crops, forests and human health. Since particulates (TSP) affect more the urban areas, Changsha City, the capital of Hunan province, was selected and the damage on human health caused by TSP was estimated. NOx was assessed over the whole province,

[71] The results of these studies are documented in three volumes entitled "Technology Assessment of Clean Coal Technologies for China." Volume III describes the methodology developed to integrate environmental considerations in power system planning including externalities.
[72] Ref: Rowe et al, "New York Externality Model," 1994.
[73] Income per capita data (purchasing power parity basis) were obtained from the World Bank "World Development Report 1996/From Plan to Market."
[74] The World Bank/ESMAP, "Environmental Compliance in the Energy Sector: Methodological Approach and Least-cost Strategies; Shanghai Municipality & Henan and Hunan Provinces, China," August 2000.

but the dispersion analysis was not as detailed as the SO_2. Table A25.3 provides a summary of the key parameters considered in these assessments.

Table A25.3: Key Parameters for Hunan Externality Costs Assessment

	SO_2	*TSP*	*NO_x*
Geographical Region	Hunan Province	Changsha City	Hunan
Base Year	1995	1998	1998
Period of Analysis	2000-20	2000-20	2000-20
Increments	5 years	5 years	5 years
Damage Considered	Crops, Forest Human Health	Human Health (from TSP only)	Health, Material Visibility

Sources: The World Bank/ESMAP.

A dose-response technique was used to estimate decreased yield of crop and forest damage. Human health cost was estimated using previous studies employing the human capital approach and the willingness to pay approach, generating a linear relationship between damages and SO_2 concentration. The results are presented in Table A25.4.

Table A25.4: Hunan Province: SO_2 Emission Damage Costs (1995-2000)

Year		*1995*	*2000*	*2005*	*2010*	*2015*	*2020*
Emission (10^6 ton)							
Nonpower		0.80	0.88	1.06	1.24	1.43	1.63
Power		0.09	0.10	0.11	0.14	0.22	0.32
Total		**0.89**	**0.99**	**1.17**	**1.38**	**1.65**	**1.95**
Damage Cost (billion RMB)	Crops Health Forest	0.54 0.38 1.20	0.60 0.84 1.55	0.74 1.46 2.38	0.93 2.32 3.47	1.16 3.43 4.92	1.42 4.98 6.50
	Total	**2.12**	**2.99**	**4.58**	**6.72**	**9.51**	**12.90**
Damage Cost							
(RMB/ton)		2,384	3,022	3,912	4,884	5,736	6,595
(US$/ton)[75]			**364**	**471**	**588**	**691**	**795**

Sources: The World Bank/ESMAP.

[75] *Note: Assume exchange rate of 8.3 RMB/US$.*

To estimate TSP-related damage, dose-response functions were used based upon research of the effects of TSP on human health in Chongqing, and which included three kinds of effects: mortality, hospitalization and visits to a medical doctor. Then, a variant of the New York State model was used. Based upon the annual emission level for TSP and the estimated population by local, regional and distant, deposition of TSP was estimated. By using the per capita GDP purchasing power parity, the damage cost from the United States was converted to Hunan province. The results of the TSP analysis are presented in Table A25.5.

Table A25.5: TSP Emission Damage Costs in Changsha City and Hunan Province

	1998	*2000*	*2010*	*2020*
Emissions, ton/year (000)				
Changsha City	20	20.7	24.5	30.9
Hunan Province	1,342	1,417	1,677	2,113
Total Damage Cost (M RMB)				
Changsha City	196	271	631	1,177
Hunan Province	6,810	9,420	21,930	40,900
Incremental Cost (RMB/ton)				
Changsha City	9,991	13,098	25,756	38,125
Hunan Province	5,073	6,651	13,078	19,358
Incremental Cost (US$/ton)				
Changsha City	1,204	1,578	3,103	4,593
Hunan Province	**611**	**801**	**1,576**	**2,332**

Sources: The World Bank/ESMAP.

For NO_x, there are two major sources: coal combustion and automobiles. For valuation of the damage cost, an emissions-based valuation method and the New York methodology was used. The results are shown in Table A25.6.

Table A25.6: NO_x Emission Damage Costs in Changsha City and Hunan Province

	1998	*2000*	*2010*	*2020*
Emissions, ton/year (000)				
Changsha City				
Hunan Province	433	362	256	247
Total Damage Cost (M RMB)				
Changsha City				
Hunan Province	552	605	842	1,195
Incremental Cost (RMB/ton)				
Changsha City				
Hunan Province	1,275	1,671	3,286	4,865
Incremental Cost (US$/ton)				
Changsha City				
Hunan Province	**154**	**201**	**396**	**586**

Sources: The World Bank/ESMAP.

Using Environmental Externalities for Selecting Power Generation Technologies

Usually the technology and the fuel characteristics determine the level of each pollutant being emitted (for example, in tons/MWh). If the externality cost (US$/ton) is known, the plant causes a damage equivalent to: tons/MWh x US$/ton = US$/MWh. From the analytical point of view, externality cost is a component which could be added to the variable O&M costs (US$/MWh) of each plant or technology. If such externality costs are included in technology evaluations, the comparison internalizes externalities.

Many of the models used in power system planning and technology evaluation include inputs for externality costs (US$/ton) for the key pollutants. If they do not, the analyst would need to calculate the externality costs in US$/MWh (tons/MWh x US$/ton) for each technology and add it to the variable O&M costs. This could be done in a sophisticated power system planning model, as well as in simple spreadsheets developed by the analyst to do technology screening or more detail technology evaluation.

The key question is always *what is the right externality value to use?* As mentioned earlier, externality values are site-specific and only after a thorough evaluation of site-specific considerations could be developed. However, very often even a preliminary assessment could be insightful. For example, the following steps could be taken:

- *Step 1:* Review relevant literature and identify a range for externality values of each pollutant;
- *Step 2:* Adjust these values to reflect population density and income in the site being considered (vs. literature data); and
- *Step 3:* Carry out a sensitivity analysis using the high and low externality values from the range being established in the previous step. If neither the low nor the high externality values change the technology choice (not uncommon), there is no need for more detail externality evaluation, at least with regard to technology choice. If the externality values change the technology choice, more detailed, site-specific assessment of the environmental externalities may be needed.

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	Lead Elimination from Gasoline in Sub-Saharan Africa. Sub-regional Conference of the West-Africa group. Dakar, Senegal March 26-27, 2002 (Deuxième comité directeur : La route à suivre - L'initiative sur l'assainissement de l'air. Paris, le 13-14 mars 2003)	12/03	046/03
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