2004 Integrated Resource Plan
Supply-Side Data

LG&E Energy

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1.0 Summary Overview

Black & Veatch was retained by LGE Energy (LGE) to develop cost and performance information for a number of conventional, renewable, and advanced technology supply-side generation resource alternatives for use in the development of its integrated resource plan. The assignment was essentially an update of estimates made in 2002. In total, estimates for 43 different supply-side resource alternatives were developed. Of these, 16 are conventional gas fired and coal fired generation alternatives widely used in the power industry, with the remainder generally classified as renewable or advanced technologies.

The cost and performance information developed in this report is summarized in Table 1-1. All costs are Total Plant Costs, estimated in 2004 dollars, but do not include Owner's costs. Output and heat rate performance estimates in the table are for summer (90° F) and ISO (59° F) conditions, with winter (20° F) ratings included in the main text of the report. Estimated capital costs are stated in Table 1-1 on a cost per kW basis at 90° F and ISO conditions.

The main text of the report includes a description of each technology and a more detailed breakdown of cost and performance estimates. The remainder of the report is organized as follows:

- Section 2.0 contains information for the selected Conventional Technologies
- Section 3.0 contains information for the selected Renewable Technologies
- Section 4.0 contains information for the selected Waste to Energy Technologies
- Section 5.0 contains information for selected Advanced Technologies
- Section 6.0 contains information for selected Energy Storage Technologies
- Appendix A contains emissions information for selected coal and gas fired technologies

Table 1-1
Generating Technology Option Summary (costs in $2004)

Unit Type	Fuel Type	Output 90° F MW	Output 59° F MW	Cost 90° F $/KW	Cost 59° F $/kW	Fixed O&M (@ISO) ($/KW-yr)	Variable O&M ($/MWH)	NPHR 90° (Btu/kWh)	NPHR 59° F (Btu/kWh)	Comm Avail.	Tech. Rating
Combustion Turbine											
Simple Cycle GE LM6000 CT – 43.7 MW	Gas	31	43.7	$740	$525	$23.3	$2.7	10,329	8,990	Yes	Mature
Simple Cycle GE 7EA CT – 85.4 MW	Gas	73	85.4	$479	$409	$16.7	$6.4	12,420	11,560	Yes	Mature
Simple Cycle GE 7FA CT – 171.7 MW	Gas	148	171.7	$329	$283	$11.2	$13.1	11,132	10,450	Yes	Mature
Combined Cycle GE 7EA CT – 130 MW	Gas	118.5	130.0	$860	$784	$17.9	$4.0	7,772	7,545	Yes	Mature
Combined Cycle GE 7FA CT – 262 MW	Gas	235.8	262	$648	$581	$13.2	$3.9	7,032	6,755	Yes	Mature
Combined Cycle 2x1 GE 7FA CT – 530 MW	Gas	483.9	530	$504	$460	$10.5	$3.9	6,974	6,700	Yes	Mature
W 501F CC CT – 283 MW	Gas	258	283	$609	$555	$11.9	$3.4	7,337	7,265	Yes	Mature
Kalina Cycle CC CT - 275 MW	Gas	50 - 500		$635 - $800		$4.3 - $11.0	$1.6 - $4.3	6,700		No	Development
Cheng Cycle CT - 140 MW	Gas	25 – 250		$740 - $1,170		$6.4 - $11.0	$1.6 - $4.3	8,000 – 9,000		No	Development
Humid Air Turbine Cycle CT - 450 MW	Gas	250 – 650		$425 - $635		$5.3 - $9.5	$1.6 - $4.3	6,500		No	Development
Peaking Microturbine - 0.03 MW	Gas	0.015 – 0.060		$1,000 – $1,200		In VOM	$10.0 - $20.0	12,200		Yes	Commercial
Baseload Microturbine - 0.03 MW	Gas	0.015 – 0.060		$1,000 - $1,200		In VOM	$10.0 - $20.0	12,200		Yes	Commercial
Coal Fired Generation											
Supercritical Pulverized Coal - 500 MW	Coal	500	500	$1,341		$22.3	$1.9	9,590		Yes	Mature
Supercritical Pulverized Coal, High Sulfur, 500 MW	Coal	500	500	$1,420		$23.9	$3.5	9,398		Yes	Mature
Subcritical Pulverized Coal, 250 MW	Coal	250	250	$1,615		$29.8	$2.0	9,976		Yes	Mature
Subcritical Pulverized Coal, 500 MW	Coal	500	500	$1,289		$22.9	$1.8	9,756		Yes	Mature
Subcritical Pulverized Coal, High Sulfur, 500 MW	Coal	500	500	$1,369		$24.4	$3.5	9,560		Yes	Mature
Supercritical, Pulverized Coal, 750 MW	Coal	750	750	$1,211		$19.1	$1.9	9,383		Yes	Mature
Supercritical, Pulverized Coal, High Sulfur, 750 MW	Coal	750	750	$1,285		$20.6	$3.5	9,195		Yes	Mature
Circulating Fluidized Bed, 250 MW	Coal	250	250	$1,674		$32.6	$2.0	10,034		Yes	Mature
Circulating Fluidized Bed, 500 MW	Coal	500	500	$1,302		$22.5	$1.9	9,812		Yes	Mature
IGCC, 267 MW	Coal	267		$1,648		$47.2	$5.9	8,500		Yes	Mature
IGCC, 534 MW	Coal	534		$1,541		$32.2	$5.5	8,500		Yes	Mature
Pressurized Fluidized Bed Combustion, 250 MW	Gas	150 - 350		$1,430 - $1,950		$21.0 - $37.0	$4.0 - $5.3	8,000 – 9,000		No	Development
Energy Storage											
Pumped Hydro Energy Storage, 500 MW	Charging Only	30 – 1,500 +		$1,250 - $2,100		$5 - $13	$2.5 - $4.5	-		Yes	Commercial
Lead-Acid Battery Energy Storage, 5 MW	Charging Only	5		$850 - $1,700		$14.3	$53 - $106	-		Yes	Commercial
Compressed Air Energy Storage, 500 MW	Gas and Charging	500		$730		$11	$4.3	4,175		Yes	Commercial

Unit Type	Fuel Type	Output 90° F MW	Output 59° F MW	Cost 90° F $/KW	Cost 59° F $/kW	Fixed O&M (@ISO) ($/KW-yr)	Variable O&M ($/MWH)	NPHR 90° (Btu/kWh)	NPHR 59° F (Btu/kWh)	Comm Avail.	Tech. Rating
Renewable Energy											
Wind Farm, MW	No Fuel	50		$1,000 - $1,800		$30	-	NA		Yes	Commercial
Wind Distributed, MW	No Fuel	0.6		$1,800 - $2,600		$35	-	NA		Yes	Commercial
Geothermal, MW	Renew	30		$2,500 - $4,000		$200 - $300	-	NA		Yes	Commercial
Solar Photovoltaic Commercial or LGE, kW	No Fuel	50		$7,500 - $9,500		$20	$23	NA		Yes	Commercial
Solar Photovoltaic Residential, kW	No Fuel	4		$8,500 - $12,500		$45	$52	NA		Yes	Commercial
Solar Thermal, Parabolic Trough, MW	No Fuel	100		$4,000 – $5,000		-	$25 - $30	NA		Yes	Commercial
Solar Thermal, Parabolic Dish, MW	No Fuel	1.2		$3,000 – $4,000		-	$10 - $20	NA		Yes	Commercial
Solar Thermal, Central Receiver, MW	No Fuel	50		$5,000 - $7,000		-	$10 - $20	NA		No	Development
Solar Thermal, Solar Chimney, MW	No Fuel	200		$3,500 - $4,500		-	$10 - $20	NA		No	Development
Waste to Energy											
MSW Mass Burn, MW	MSW	7		$5,000 - $7,000		$250 - $350	$65 - $85	17,500		Yes	Commercial
RDF Stoker-Fired, MW	RDF	7		$7,000 - $9,000		$450 - $550	$70 - $90	19,300		Yes	Commercial
Landfill Gas IC Engine (LGE), MW	Landfill Gas	0.2 - 15		$1,300 - $2,700		-	$15	NA		Yes	Commercial
TDF Multi-Fuel CFB (100% Co-fire), MW	Tires	20		$3,500 - $5,500		$80 - $120	$7 - $9	12,500		Yes	Commercial
TDF Multi-Fuel CFB (10% Co-fire), MW	Tires	100		$1,800 - $2,530		$40 - $75	$3 - $6.5	11,800 – 13,600		Yes	Commercial
TDF Multi-Fuel CFB (LGE), MW	Tires	50		$2,500		$60	$3	Based on LGE Generation Stations		Yes	Commercial
Anaerobic Digestion (LGE), MW	Manure	0.085		$2,300 - $3,800		-	$15	NA		Yes	Commercial
Bio Mass											
Biomass (Direct), MW	Wood	30		$2,000 - $2,500		$60	$8	14,500		Yes	Commercial
Biomass (Co-fire or LGE), 10 MW	Wood	5 - 50		$50 - $600		$5 - $20	$25 - $65	9,000 – 12,000		Yes	Commercial
Hydroelectric Power											
Hydroelectric (New), MW	No Fuel	< 50		$2,500 - $4,500		$5 - $25	$2.5 - $6	NA		Yes	Mature
Hydroelectric (Incremental or LGE), MW	No Fuel	1 - 160		$600 - $3,000		$5 - $25	$2 - $6	NA		Yes	Mature
Other											
Spark Ignition Engine, kW	Gas	1 – 5,000		$450 - $1,100		-	$15 - $25	9,700		Yes	Commercial
Compression Ignition Engine, kW	Diesel	1 – 10,000		$350 - $800		-	$15 - $25	7,800		Yes	Commercial
Fuel Cell, 0.2 MW	Gas	0.1 – 0.25		$5,000 - $7,000		$500 - $700	$5 - $10	7,000 - 9,500		Yes	Commercial

Table 1-1 continued

Generating Technology Option Summary (costs in $2004)

1.1 Basis of Estimates

This report contains performance, O&M, emissions, and capital cost information for the selected technologies. The EPC capital costs provided in this report do not include Owner's costs as listed in Table 1-2, that may apply and that are typically very site and project specific. The most costly factors from this list are typically the project development costs, financing costs (especially interest during construction), and off-site utility interconnections. Based on the experience of Black & Veatch on numerous actual projects, the Owner's costs can be highly variable from one project to another. A recent review of over two dozen projects indicates a range in the Owner's costs from 28 to 71 percent of the total plant cost. Based on these projects, the average value of Owner's cost was 40 to 44 percent of the total base plant cost.

A consideration that could significantly affect Owner's cost is whether the owner is a regulated utility or an independent power producer (IPP), as IPP projects typically have higher Owner's costs. The projects studied by Black & Veatch were mostly IPP projects, suggesting that an LGE project could have Owner's costs lower than the average value indicated above. Savings for a utility-owned project would likely arise for the following reasons:

1. detailed project agreements requiring legal, financial, and technical advisors would be avoided for a plant going into rate base,
2. a debt reserve fund for the project would be avoided for an investor-owned utility and could possibly be avoided for a municipal or cooperative utility,
3. financing costs and fees may be lower,
4. fuel and consumables prior to commercial operation may be recoverable through rates,
5. interest during construction (IDC) or AFUDC costs may be lower than for a limited recourse project to the degree that project cost of capital is below that for a utility-owned project (although this could be partially or wholly offset in that IPP projects typically involve a shorter construction and pre-construction period).

Considering these factors, it is reasonable to assume that the total Owner's costs for an investor-owned utility are approximately 10 percent lower than for an IPP project, or in the 30 to 34 percent range.

The other primary issue involved in determining an appropriate Owner's cost allocation for planning purposes concerns the type of plant being developed. Some Owner's costs are comparable in absolute costs across technologies, implying a declining

Table 1-2
Possible Owner's Costs

Project Development:

- Site selection study
- Land purchase / options / rezoning
- Transmission / gas pipeline rights of way
- Road modifications / upgrades
- Demolition (if applicable)
- Environmental permitting / offsets
- Public relations / community development
- Legal assistance

Utility Interconnections:

- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Electrical transmission
- Supply water
- Wastewater / sewer (if applicable)

Spare Parts and Plant Equipment:

- AQCS materials, supplies, and parts
- Steam turbine materials, supplies, and parts
- Boiler materials, supplies, and parts
- Balance-of-plant equipment / tools
- Rolling stock
- Plant furnishings and supplies

Owners Project Management:

- Preparation of bid documents and selection of contractor/s and suppliers.
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup / Construction Support:

- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals / reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing

Taxes / Advisory Fees / Legal:

- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - PPA
  - Interconnect agreements
  - Contracts-procurement & construction
  - Property transfer

Owner's Contingency:

- Owner's uncertainty and costs pending final negotiation:
  - Unidentified project scope increases
  - Unidentified project requirements
  - Costs pending final agreement (e.g., interconnection contract costs)

Financing:

- Financial advisor, lender's legal, market analyst and engineer
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

cost in percentage terms for more capital intensive options, while other cost items would be significantly higher in absolute costs and perhaps in percentage terms. For example, any power plant requiring a Certificate of Need from a state utility commission prior to construction would be expected to incur relatively comparable costs for this process among technology types meaning, on a percent basis, the cost would be much lower for a coal unit than for a simple cycle unit. On the other hand, IDC costs for a large power plant would be much larger in absolute terms and in percent terms for a coal plant relative to a simple cycle and even a combined cycle plant due to the long construction period involved.

The Black & Veatch study that estimated a 40 to 44 percent Owner's cost level (adjusted above to 30 to 34 percent for utility-owned units) consisted primarily of combined cycle units. While the variation is large with any technology, based on a cursory review of other studies with which Black & Veatch has been involved, the following percent adders are reasonable for planning purposes:

- PC, CFB, IGCC units: Owner's costs 30 percent of the EPC cost when including IDC; 15 percent not including IDC
- Combined cycle: Owner's costs 30 percent of the EPC when including IDC; 22 percent not including IDC
- Simple cycle: Owner's costs 23 percent of the EPC cost when including IDC; 17 percent not including IDC
- Renewables: Owner's costs 20 percent of the EPC cost when including IDC; 16 percent not including IDC

The conventional cost estimates in the report include costs for equipment and materials, construction labor, engineering services, construction management, indirect and other costs. The estimates are based on Black & Veatch proprietary estimating templates and experience. These estimates are screening level estimates prepared for the purpose of project screening, resource planning, comparison of alternative technologies, etc. The information is consistent with recent experience and market conditions, but as shown in the last few years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility in the future, and the estimates in this report do not constitute an offer by Black & Veatch to perform the work or provide equipment and materials at the values presented herein. The air quality control systems for each technology were selected to meet typical recent BACT levels for criteria pollutants including NOx, SO2, and PM. Mercury control was not included in the estimates.

Given the level of uncertainty with developing screening level capital costs, it is recommended that sensitivity evaluations be conducted to determine the competitiveness of a technology that appears cost-effective under base case assumptions. As a first analysis, Black & Veatch believes that it is reasonable to perform capital cost sensitivities assuming that capital costs are 15 percent above and below the base case capital costs. If the economics of the plan appear marginal, it is appropriate to develop additional and site specific capital cost estimates.

One of the current uncertainties associated with new power plant construction is the price of steel, which has been driven up sharply in the past several months due to a world-wide increase in the demand for scrap metal. While it appears that the growth in the world economy, especially China, will tend to keep prices elevated in the short run, it is very difficult to predict whether the current price increase is a permanent step increase, or is only a short-term phenomena. While Black & Veatch has not performed a detailed evaluation of the potential impact of high steel prices on power plants for this study, approximate estimates made for other projects indicate that the impact may be on the rough order of magnitude of approximately 5 percent for conventional alternatives. While additional analysis is required to add confidence to this estimate, the recommended 15 percent capital cost sensitivity is almost certainly sufficient to account for the possibility that the increase in steel prices is a relatively long-term phenomenon.

2.0 Conventional Generation Alternatives

This section contains cost and performance information for conventional generation resources that are proven technologies, commercially available and widely used in the power industry. These include three natural gas fired simple cycle combustion turbines, four combined cycle combustion turbines, five pulverized coal configurations, two circulating fluidized bed coal technologies, and a small gas fired reciprocating engine plant.

2.1 Simple Cycle Combustion Turbines

Natural gas fired combustion turbines are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air then heating the pressurized air to approximately 2,000 °F or more by burning oil or natural gas, and then expands those hot gases through a turbine. The turbine drives both the air compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel energy to electric power. A substantial portion of the fuel energy is wasted in the form of hot (900-1,100 °F) gases exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gasses, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices and performance changes with ambient conditions. Generally speaking, as temperatures rise, combustion turbine efficiency and output decreases due to the lower density of the air. To lessen the impact of this negative characteristic, most conventional power plants now include inlet air cooling systems to boost plant performance at higher ambient temperatures. Combustion turbine pollutant emission rates typically higher at part load. This limitation has an effect on how far plant output can be decreased without exceeding pollutant emission limits. Aeroderivative turbines tend to have better part-load operating performance than the larger, heavy-duty industrial gas turbines. It is estimated that the simple cycle combustion turbine plant output can be reduced to approximately 50 percent load and maintain emission levels within required limits.

The popularity of combustion turbines has been widely established in both the domestic and international power generation markets. Advantages of simple cycle combustion turbine projects include low capital cost, short design and installation schedules, and the availability of many unit sizes. Simple cycle technology also provides many of the same positive attributes as reciprocating engines, including rapid startup and modularity for ease of maintenance. In addition, combustion turbines have several advantages over reciprocating engines, including lower emissions and lower capital cost.

The primary drawback is that, due to the cost of natural gas and fuel oil, the per MWh variable cost is high compared to coal and even combined cycle units. As a result, simple cycle combustion turbines are often the technology of choice for peaking service in the power industry, but are not usually economical for baseload or intermediate usage.

2.1.1 Performance of Selected Simple Cycle Units

In this section, the performance of three simple cycle units selected for study is presented. This will be followed by a more detailed breakdown of O&M costs in Section 2.1.2 and capital cost information for these options in Section 2.1.3.

2.1.1.1 GE LM6000 Combustion Turbine

The General Electric LM6000 is a 2-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine. The CF6-80C2 has logged more than 30,000,000 flight hours in the Boeing 747 and other wide-body aircraft.

The LM6000 consists of a 5-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a 2-stage air-cooled high pressure turbine (HPT) and a 5-stage low pressure turbine (LPT), and accessory drive gear box. It has two concentric rotor shafts. The LPC and LPT are assembled on one shaft, forming the low-pressure rotor. The HPC and HPT are assembled on the other shaft, forming the high-pressure rotor. The LPT, HPC, HPT and combustors of the LM6000 are virtually identical with the CF6-80C2. This use of flight-proven parts, produced in high volume, contributes to relatively low initial cost and high operating efficiency of the LM6000.

The LM6000 uses the LPT to power the output shaft. By eliminating the separate power turbine found in many other gas turbines, the LM6000 design simplifies the engine, improves fuel efficiency and permits direct-coupling to 3,600 RPM generators for 60 Hz power generation. The gas turbine drives its generator through a flexible dry type coupling connected to the front, or "cold", end of the LPC shaft. The LM6000 gas turbine generator set has the following advantages:

- Full power in 10 minutes
- Cycling, or peaking
- Synchronous Condensor capability
- Compact, modular design

- 5 million operating hours
- More than 450 turbines sold
- 97.8 percent documented availability
- LM6000PC — water or steam injection
- LM6000PD — dry-low emission combustion
- LM6000 SPRINT™ spray inter-cooling for power boost

The LM6000 combustion turbine characteristics at summer (90° F), ISO (59° F), and winter (20° F) conditions are shown in Table 2-1.

Table 2-1
LM6000 Combustion Turbine Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat Rate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		49.3	9,314		
Summer (90° F)		31	10,329		
ISO (59° F)		43.7	8,990	$23.3	$2.71
	14.5				

2.1.1.2 GE 7EA Combustion Turbine

The GE PG7121EA (7EA) model is a highly reliable, mid-size packaged combustion turbine developed specifically for 60 Hz applications. With design emphasis placed on energy efficiency, availability, performance and maintainability, the GE 7EA is a proven technology with about 750 units installed worldwide. The simple, medium-sized design of the GE 7EA lends to flexibility in plant layout and easy, low-cost addition of increments of power when phased capacity expansion is necessary. The GE 7EA is well suited for situations that require high plant efficiency along with the back-up power only multiple units can provide. Rated at 85.4 MW, the unit has a 3,600 rpm shaft speed and is direct coupled to the generator. The GE 7EA is fuel-flexible, and can operate on natural gas, liquefied natural gas (LNG), distillate, and treated residual oil. The GE 7EA can be used for simple cycle and combined cycle, base load and peaking power generation, and industrial and cogeneration application. The GE 7EA combustion turbine has the characteristics presented in Table 2-2.

Table 2-2
GE 7EA Combustion Turbine Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		96.8	11,466		
Summer (90° F)		73.0	12,420		
ISO (59° F)		85.4	11,560	$16.68	$6.42
	21				

2.1.1.3 GE 7FA Combustion Turbine

GE 7FA gas turbines, introduced in 1986, are the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research & Development Center. This program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design and new alloys to F class gas turbines, enabling them to attain higher firing temperatures (2,400° F) than previous generation machines.

The GE 7FA gas turbines have an 18-stage compressor and a 3-stage turbine. They feature cold-end drive and axial exhaust which is beneficial for combined cycle arrangements. Net efficiencies over 56 percent can be achieved. With reduced cycle time for installation and start-up, The GE 7FA gas turbines can be installed relatively quickly. The packaging concept of GE 7FA features consolidated skid-mounted components, controls, and accessories. This standardized arrangement reduces piping, wiring, and other on-site interconnection work.

GE 7FA also has displayed outstanding environmental characteristics. Because of the higher specific output of these machines, less NOx and CO are emitted per unit of power produced for the same exhaust concentrations. GE 7FA machines have accumulated over 900,000 operating hours on Dry Low NOx burners.

The GE 7FA combustion turbine has the following characteristics, presented in Table 2-3.

2.1.2 Basis for O&M Estimates

The O&M summaries for the simple cycle technologies listed in Section 2.1.1 are derived from more detailed estimates developed by Black & Veatch, based on vendor estimates and recommendations, actual performance information gathered from units in-service, and representative costs for staffing, materials, and supplies. The more detailed

O&M estimates are shown in Table 2-4. These estimates are based on the unit ISO ratings and calculations assume a 15 percent capacity factor for the simple cycle units.

Table 2-3
GE 7FA Combustion Turbine Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		185.2	10,349		
Summer (90° F)		148	11,132		
ISO (59° F)		171.7	10,450	$11.2	$13.13
	22				

Fixed O&M costs assume that units are at a Greenfield site and are not operated remotely. Plant staffing is assumed to provide operating and routine maintenance. Additional maintenance related to periodic overhauls and major inspections are assumed to be provided through maintenance contracts or contract services. These outage maintenance costs, though occurring periodically depending on hours of operation and number of starts, have been annualized in the outage maintenance cost category in Table 2-4.

2.1.3 Simple Cycle Capital Costs

Capital costs in July, 2004 dollars for the three simple cycle options are summarized in Table 2-5. The combustion turbine market is very dynamic and prices have varied significantly during the past 5 years based upon supply and demand conditions. Such volatility may extend into the future, albeit probably to a lesser degree given the adequacy of current reserve margins and the move away from purely merchant plants. The basis for the capital costs in Table 2-5 are discussed below.

2.1.3.1 General Assumptions

1. The site is a Greenfield site located near Louisville Kentucky, and is reasonably level and clear. Demolition of any existing structures is included in Owner's costs.
2. The site has sufficient area available to accommodate construction activities including, but not limited to offices, lay-down, and staging.

Table 2-4
Simple Cycle O&M Costs (in $2004)

Fixed Costs ($1,000)	LM6000 (43.7 MW)	7EA (85.4 MW)	7FA (171.7 MW)
Labor			
Operations	$418	$418	$418
Maintenance	$320	$418	$418
Technical Services	$0	$0	$0
Administration	$0	$0	$0
Labor Sub-Total	*$738*	*$836*	*$836*
Maintenance			
Combustion Turbine	$18	$35	$35
Steam Turbine & Steam Plant	$0	$0	$0
HRSG	$0	$0	$0
Cooling Tower	$0	$0	$0
Water Treatment Facilities	$0	$0	$0
Waste Water Treatment	$1	$3	$6
Pollution Control	$2	$4	$7
I&C and Electric Plant	$5	$11	$22
Contracted Services	$8	$18	$37
Maintenance Sub-Total	*$33*	*$71*	*$107*
Other Expenses			
Emission Fees			
Training	$18	$20	$20
Property Taxes	$62	$146	$296
Office and Administrative Expenses (incl	$37	$42	$42
Insurance	$124	$292	$592
Other Fees	$8	$18	$37
Other Fixed Expenses Sub-total	*$249*	*$518*	*$987*
Total Fixed Costs	**$1,020**	**$1,424**	**$1,930**
Variable Costs ($1,000)			
Outage Maintenance			
Outage Maintenance - Combustion Turbine	$128	$631	$2,815
Outage Maintenance - Steam Turbine	$0	$0	$0
SCR Catalyst Replacement	$42	$60	$102
CO Catalyst Replacement	$11	$15	$26
Other Major Replacements	$0	$0	$0
Allowance for Emergent Repairs	$0	$0	$0
Outage Maintenance Sub-total	*$180*	*$706*	*$2,943*
Utilities			
Electricity	$9	$9	$11
Water	$0	$0	$0
Sewage	$0	$0	$0
Other Disposals	$0	$0	$0
Utilities Sub-total	*$9*	*$9*	*$11*
Chemical Usage			
Feedwater	$0	$0	$0
Cooling tower	$0	$0	$0
Treatment/Pre-Treatment	$0	$0	$0
SCR Ammonia Consumption	$4	$5	$9
Chemical Usage Sub-total	*$4*	*$5*	*$9*
Total Variable Costs	**$193**	**$721**	**$2,963**
Total O&M Costs	**$1,213**	**$2,145**	**$4,893**
Annual Net Generation (MWh)	71,126	112,216	225,614
Fixed Costs per net unit of capacity, $/kW-y	**$23.34**	**$16.68**	**$11.24**
Variable Costs per unit of output, $/MWh	**$2.71**	**$6.42**	**$13.13**

Table 2-5
Capital Costs for the Simple Cycle Units (in $2004)

Description	LM 6000	GE 7EA	GE 7FA
Purchase Contracts:	**($1,000)**	**($1,000)**	**($1,000)**
Civil / Structural	$530	$835	$1,190
Mechanical	$1,300	$2,400	$2,650
Combustion turbine	$11,500	$18,000	$25,000
Electrical	$2,700	$3,600	$5,100
Control	$50	$60	$75
Chemical	$210	$255	$280
Subtotal Purchase Contracts:	$16,290	$25,250	$34,295
Construction Contracts:			
Civil / Structural Construction	$1,100	$1,350	$1,635
Mechanical / Chemical Construction	$530	$1,050	$1,470
Electrical / Control Construction	$320	$600	$1,165
Service Contracts & Construction Indirects	$1,650	$2,740	$4,620
Subtotal Construction Contracts:	$3,600	$5,740	$8,890
Total Direct Costs:	$19,890	$30,990	$43,185
Indirect Costs:			
Engineering Costs	$1,530	$1,530	$1,840
Construction Management	$380	$655	$1,100
Startup Spare Parts	$90	$140	$195
Construction Utilities	By Owner	By Owner	By Owner
Project Insurance	$80	$125	$175
Project Contingency	$480	$760	$1,100
EPC Contractor EBIT	$480	$760	$1,100
Total Indirect Costs:	$3,040	$3,980	$5,510
Total Contracted Costs:	$22,930	$34,960	$48,695
Escalation – Not Included	$0	$0	$0
Owner Costs – Not Included	$0	$0	$0
Total Capital Requirements:	**$22,930**	**$34,960**	**$48,695**
Net Plant Output (ISO)	43.7	85.4	171.7
Specific Capital Cost, $/kW (ISO)	**$525**	**$409**	**$283**

3. Each plant estimate will feature one (1) dual fueled combustion turbine. The primary fuel will be natural gas and the back-up fuel will be No. 2 fuel oil. The cost of unloading and delivery to the project site is included. The facility site is assumed to be capable of being expanded for duplicate units
4. The combustion turbine includes a standard sound enclosure.
5. Spread footings are assumed for all equipment foundations. Stabilization of the existing subgrade is not anticipated.
6. The buildings are pre-engineered.
7. The source of water will be the local water district. Demineralized water will be provided by on site demineralizers for use when firing fuel oil.
8. A sanitary sewer system is included.
9. Construction power is available at the site boundary.
10. Supply of natural gas will be available at the site boundary at the appropriate conditions that meet the combustion turbine vendor requirements. Fuel oil will be delivered by truck to the storage tank.
11. Substation and power transmission lines are not included and this should be included in the Owner's costs.
12. Field Erected Tanks consisting of the following:
    - Service/Fire Water Storage Tank
    - Fuel Oil Storage Tank
    - Demineralized Water Storage Tank
13. Fire protection will consist of the major equipment vendor's standard fire suppression system, water deluge of the transformers.

2.1.3.2 Direct Cost Assumptions

1. Total direct capital costs are expressed in July 2004 dollars. Escalation has not been included.
2. Direct costs include the costs associated with the purchase of equipment, erection and contractors' service.
3. Construction costs are based on a traditional, multiple contracts, contracting philosophy.
4. Spare parts for start-up are included. Spare parts for use during operation are included in Owner's costs.
5. Permitting and licensing are included in the Owner's costs.
6. An average burdened wage rate of $31/hour has been assumed.

2.1.3.3 Indirect Cost Assumptions

The following items of cost are included in the base cost estimate.

1. General indirect costs, which include all necessary services required for checkouts, testing services, and commissioning.
2. Insurance including builder's risk and general liability.
3. Engineering and related services costs are included.
4. Field construction management services include field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
5. Technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond and liability insurance for equipment and tools.
6. Contractors' contingency and profit is included in the estimate.
7. Transportation costs for delivery to the job site is included in the base plant estimate.
8. Start-up/commissioning spare parts are included in the base estimate.
9. Contingency for direct and indirect costs is included.
10. Owner's costs in Table 1-2 are not included.

2.2 Combined Cycle Combustion Turbines

A combined cycle power plant uses one or more combustion turbine generators and steam turbine generators to produce electrical energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. High-pressure steam is produced when the hot gas exhaust from the combustion turbine is passed through a heat recovery steam generator (HRSG). The high-pressure steam is then expanded through a steam turbine which spins an electric generator. Exhaust gas heat recovery is more cost effective on combustion turbines than reciprocating engines because the combustion turbine exhaust gas temperatures are almost twice as high.

Combined cycle combustion turbines have several advantages over both the reciprocating engines and the simple cycle combustion turbines. These include lower NO_x and CO emissions using more conventionally applied technology and potentially greater operating flexibility if duct burners are used.

Disadvantages of a combined cycle plant relative to the simple cycle and reciprocating engine plants include a reduction in plant reliability and increase in the overall staffing and maintenance requirements due to the added plant complexity.

Combined cycle power plants were the generation technology of choice for most baseload and intermediate service plants constructed by the domestic power industry in the 1995-2003 time frame due to their high efficiency, relatively quick construction period, and relatively modest natural gas prices. Recent natural gas price volatility, however, has again caused utilities to seriously consider and pursue coal fired generation as a base load alternative in many regions of the nation.

2.2.1 Performance of Selected Combined Cycle Units

In this section, the performance of four combined simple cycle units selected for study is presented. This will be followed by a more detailed breakdown of O&M costs in Section 2.2.2 and capital cost information for these options in Section 2.2.3.

2.2.1.1 The 1 x 1 GE 7EA Combined Cycle

An HRSG and a steam turbine generator connected with a GE 7EA combustion turbine would form this combined cycle configuration. In the HRSG, the heat energy in the exhaust flow of the gas turbine is used to produce steam to drive the steam turbine generator. Changing the GE 7EA simple cycle to combined cycle will increase the electric output from about 85 MW to 130 MW and increase the plant efficiency from 32.7 percent to 50.2 percent. The 1x1 GE 7EA combined cycle power generation unit has the performance characteristics presented in Table 2-6.

Table 2-6
1 x 1 GE 7EA Combined Cycle Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		143.2	7,818		
Summer (90° F)		118.5	7,772		
ISO (59° F)		130.0	7,545	$17.9	$3.97
	26				

2.2.1.2 The 1 x 1 GE 7FA Combined Cycle

A HRSG and a steam turbine generator connected with a GE 7FA combustion turbine would form this combined cycle configuration. In the HRSG, the heat energy in the exhaust flow of the gas turbine is used to produce steam to drive the steam turbine generator. Changing the GE 7FA simple cycle to combined cycle will increase the electric output from about 170 MW to 260 MW and increase the plant efficiency from 36.2 percent to 56.0 percent. The 1x1 GE 7FA combined cycle power generation unit has the characteristics presented in Table 2-7.

Table 2-7
1 x 1 GE 7FA Combined Cycle Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		278.3	7,137		
Summer (90° F)		235.8	7,032		
ISO (59° F)		262.0	6,755	$13.2	$3.88
	27				

2.2.1.3 The 2 x 1 GE 7FA Combined Cycle

The 2 x 1 GE 7FA combined cycle configuration is similar to a 1 x 1 GE 7FA combined cycle configuration, but includes a second GE 7FA combustion turbine, and a larger steam turbine resulting in almost double the output and a slight improvement in efficiency. Performance, capital costs, operation and maintenance costs, and construction period are shown in Table 2-8.

Table 2-8
2 x 1 GE 7FA Combined Cycle Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		563.0	7,086		
Summer (90° F)		483.9	6,974		
ISO (59° F)		530.0	6,700	$10.5	$3.93
	28				

2.2.1.4 The 1 x 1 W 501F Combined Cycle

A heat recovery steam generator (HRSG) and a steam turbine generator connected with the Siemens Westinghouse 501F combustion turbine would form this combined cycle. Performance, capital costs, operation and maintenance costs, and the construction period for this alternative are shown in Table 2-9.

Table 2-9
1 x 1 W 501F Combined Cycle Characteristics

Condition	Construction Length (months)	MW Rating	Net Plant Heat R ate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Winter (20° F)		301.7	7,191		
Summer (90° F)		258.0	7,337		
ISO (59° F)		283	7,265	$11.9	$3.38
	27				

2.2.2 Basis for O&M Estimates

The O&M summaries for the four combined cycle technologies are derived from more detailed estimates developed by Black & Veatch, based on vendor estimates and recommendations, actual performance information gathered from units in-service, and representative costs for staffing, materials, and supplies. The more detailed O&M estimates are shown in Table 2-10. These estimates are based on the unit ISO ratings and calculations assume a 75 percent capacity factor.

Fixed O&M costs assume the units are at a Greenfield site. Plant staffing is assumed to provide operating and routine maintenance. Additional maintenance related to periodic overhauls and major inspections are assumed to be provided through maintenance contracts or contract services. These outage maintenance costs, though occurring periodically, depending on hours of operation and number of starts, have been annualized in the outage maintenance cost category.

2.2.3 Combined Cycle Capital Costs

Capital cost estimates for the four combined cycle configurations are summarized in the Table 2-11. The estimates are expressed in July 2004 US dollars. The market for combustion turbines is very dynamic and prices can and do vary considerably based upon supply and demand.

Table 2-10
Combined Cycle O&M Costs (in $2004)

Fixed Costs ($1,000)	1 x 1 7EA (130 MW)	1 x 1 7FA (263 MW)	2 x 1 7FA (530 MW)	1 x 1 W 501F (283 MW)
Labor				
Operations	$686	$686	$829	$686
Maintenance	$571	$648	$648	$648
Technical Services	$0	$0	$0	$0
Administration	$65	$197	$242	$197
Labor Sub-Total	*$1,322*	*$1,531*	*$1,719*	*$1,531*
Maintenance				
Combustion Turbine	$35	$35	$70	$35
Steam Turbine & Steam Plant	$34	$71	$142	$66
HRSG	$29	$59	$119	$55
Cooling Tower	$23	$47	$95	$44
Water Treatment Facilities	$17	$35	$71	$33
Waste Water Treatment	$9	$18	$36	$16
Pollution Control	$6	$12	$47	$11
I&C and Electric Plant	$17	$35	$71	$33
Contracted Services	$29	$59	$119	$55
Maintenance Sub-Total	*$197*	*$370*	*$769*	*$347*
Other Expenses				
Emission Fees	$0	$0	$0	$0
Training	$34	$38	$44	$38
Property Taxes	$228	$470	$948	$438
Office and Administrative Expenses (incl	$66	$77	$86	$77
Insurance	$456	$940	$1,896	$876
Other Fees	$29	$59	$119	$55
Other Fixed Expenses Sub-total	*$813*	*$1,583*	*$3,092*	*$1,483*
Total Fixed Costs	**$2,332**	**$3,484**	**$5,581**	**$3,361**
Variable Costs ($1,000)				
Outage Maintenance				
Outage Maintenance - Combustion Turbine	$971	$2,690	$5,357	$2,159
Outage Maintenance - Steam Turbine	$194	$106	$260	$369
SCR Catalyst Replacement	$499	$682	$1,314	$607
CO Catalyst Replacement	$128	$26	$337	$156
Other Major Replacements	$0	$0	$0	$0
Allowance for Emergent Repairs	$0	$0	$0	$0
Outage Maintenance Sub-total	*$1,791*	*$3,503*	*$7,269*	*$3,291*
Utilities				
Electricity	$7	$7	$7	$7
Sewage	$861	$1,726	$3,435	$1,612
Other Disposals	$0	$0	$0	$0
Utilities Sub-total	*$868*	*$1,734*	*$3,443*	*$1,619*
Chemical Usage				
Cooling tower	$503	$1,038	$2,093	$967
Treatment/Pre-Treatment	$182	$375	$757	$350
SCR Ammonia Consumption	$44	$60	$116	$53
Chemical Usage Sub-total	*$729*	*$1,473*	*$2,966*	*$1,370*
Total Variable Costs	**$3,389**	**$6,710**	**$13,677**	**$6,281**
Total O&M Costs	**$5,721**	**$10,194**	**$19,258**	**$9,642**
Annual Net Generation (MWh)	854,100	1,727,910	3,482,100	1,859,310
Fixed Costs per net unit of capacity, $/kW-y	**$17.94**	**$13.25**	**$10.53**	**$11.88**
Variable Costs per unit of output, $/MWh	**$3.97**	**$3.88**	**$3.93**	**$3.38**

Table 2-11
Capital Costs for the Combined Cycle Units (in $2004)

Description	1x1 7EA	1x1 7FA	2x1 7FA	1x1 501F
Purchase Contracts:	($1,000)	($1,000)	($1,000)	($1,000)
Civil / Structural	5,400	7,900	8,500	8,100
Mechanical	9,500	17,100	21,300	17,600
Combustion turbine Generator	18,000	25,000	50,000	26,000
Steam Turbine Generator	5,500	9,400	15,700	9,900
Heat recovery Steam Generator	6,500	12,300	23,600	12,800
Electrical	4,800	7,400	10,200	7,500
Control	1,000	1,700	1,900	1,800
Chemical	800	1,400	2,300	1,400
Subtotal Purchase Contracts:	51,500	82,200	133,500	85,100
Construction Contracts:				
Civil / Structural Construction	6,400	8,700	12,800	8,900
Mechanical / Chemical Construction	7,100	10,500	17,100	10,800
Electrical / Control Construction	6,000	9,500	12,700	9,700
Service Contracts & Construction Indirects	9,000	12,300	20,100	12,600
Subtotal Construction Contracts:	28,500	41,000	62,700	42,000
Total Direct Costs:	80,000	123,200	196,500	127,100
Indirect Costs:				
Engineering Costs (With G&A)	8,900	10,700	13,800	10,700
Construction Management	4,100	6,400	9,800	6,400
Startup Spare Parts	400	500	1000	500
Construction Utilities	By Owner	By Owner	By Owner	By Owner
Project Insurance	500	600	4,100	700
Project Contingency	4,100	5,700	9,300	5,800
EPC Contractor EBIT	3,900	5,800	9,500	5,900
Total Indirect Costs:	21,900	29,700	47,500	30,000
Total Contracted Costs:	101,900	152,900	228,700	157,100
Escalation – Not Included	0	0	0	0
Owner Costs – Not Included	0	0	0	0
Total Estimated EPC cost, $ x 1000	**101,900**	**152,900**	**243,700**	**157,100**
Net Plant Output (ISO), MW	130	263	530	283
Specific Capital Cost, $/kW (ISO)	**784**	**581**	**460**	**555**

2.2.3.1 General Assumptions

The combined cycle capital cost estimates are based on the cost assumptions listed below.

1. The location is a Greenfield site near Louisville, Kentucky, and is assumed to be reasonably level and clear with no wetlands. No demolition of any existing structures is included in this cost estimate.
2. The site has sufficient area available to accommodate construction activities including but not limited to offices, laydown, and staging.
3. The plant will feature dual fueled CTG(s), HRSG(s), and one (1) condensing STG. The primary fuel will be natural gas and the back-up fuel will be No. 2 fuel oil. No consideration was given to possible future expansion of the facilities.
4. The CTG(s) include a standard enclosure.
5. A gantry or bridge crane for servicing the CTG(s) is not included.
6. By-pass dampers and stacks are not included.
7. SCR equipment to control NO_x emissions is included with the HRSG pricing. An oxidation catalyst is not included for CO control.
8. Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is included.
9. Major buildings included in the cost estimates are as follows:
   - A central control/electrical building is included for the site that is sized to enclose a control room, battery room, motor control center, meal room and toilets, locker room, and various offices.
   - The estimate includes an administration/workshop/warehouse building, which will provide administration offices, storage and workshop areas, instrument shop, a locker room, and a drawing room.
   - A water treatment building is included sufficient to enclose the water treatment equipment, and fire water pumps.
   - All buildings will be pre-engineered metal structures.
10. The source for cooling tower makeup and cycle make-up will be the local water district. On-site water treatment includes a demineralization system for cycle make-up treatment.
11. A sanitary waste sewer system is included.
12. Construction power and water is assumed to be available within the site boundary.

13. Natural gas supply is assumed to be a pipeline connection at the site boundary. Provision of a natural gas pipeline, compression station, etc., if required, will be included in the Owner's cost (not included here).
14. Natural gas will be available at the site boundary at the required volume and pressure according to the combustion turbine OEM requirements.
15. No. 2 fuel oil will be delivered by truck to a fuel oil storage tank.
16. A substation is not included. Transmission lines are not included in the base plant cost estimate. These should be included in the Owner's Cost, if required.
17. Automatic fire protection will consist of the CTG OEM supplied standard CO2 fire suppression system, water deluge of the transformers, dry pipe fire protection of the cooling tower, wet pipe sprinkler system in the buildings except in the control room which will have fire detection equipment only and hydrant protection for site.
18. A wet, mechanical draft-cooling tower will provide cycle heat rejection.
19. Field Erected Tanks consisting of the following:
    - Demineralized Water Storage Tank
    - No. 2 Fuel Oil storage Tank
    - Raw Water / Fire water Storage Tank
20. A wastewater collection system is included.
21. An emergency diesel generator for safe shutdown is included.
22. An auxiliary boiler is not included.

2.2.3.2 Direct Cost Assumptions

1. All direct costs are expressed in July 2004 dollars. Escalation is not included. This is an "overnight" cost estimate to allow the Owner to evaluate alternative commercial operation dates for the project. Escalation can be included to adjust this assumption based on a schedule provided by the owner for commercial operation of the unit.
2. Direct costs include the costs associated with the purchase of equipment, erection and all contractor services.
3. Construction costs are based on a traditional, multiple contracts, contracting philosophy. Construction is assumed to be performed based on a 50-hour work week. A local wage rate of $31/hour is assumed and includes payroll, payroll taxes and benefits. Construction indirect costs and construction equipment costs are included in the construction and service contracts portion of the estimate.

2.2.3.3 Indirect Cost Assumptions

The following indirect cost assumptions are included in the base cost estimate.

1. General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
2. Insurance including builder's risk and general liability.
3. Engineering and related services costs are included.
4. Field construction management services include field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
5. Technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond and liability insurance for equipment and tools.
6. Contractors' contingency and profit is included in the estimate.
7. Transportation costs for delivery to the job site is included in the base plant estimate.
8. Start-up/commissioning spare parts are included in the base estimate.
9. Contingency for direct and indirect costs is included.
10. Owner's costs in Table 1-2 are not included in the estimate.

2.3 Pulverized Coal (PC)

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use pulverized coal boilers. Pulverized coal units have the advantage of utilizing a proven technology with a very high reliability level. They can be sized very large and the economies of scale can result in low bus bar costs. Pulverized coal units are relatively easy to operate and maintain.

New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,000 to 4,500 psig, compared to the steam pressures of 2,400 psig for conventional subcritical boilers. The increase in pressure raises the overall efficiency. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel and other factors such as the expected capacity factor of the unit and the cost of capital.

2.3.1 Performance of Selected Pulverized Coal Units

Estimates for subcritical pulverized coal plants with full load capacities of 250 MW and 500 MW were selected for this analysis. Supercritical pulverized coal plants having full load capabilities of 500 MW and 750 MW were selected. In addition, estimates were prepared for a subcritical and supercritical 500 MW unit size assuming a high sulfur coal. Summary performance information for the PC power generation technologies is shown in Table 2-12. The O&M costs are in 2004 dollars, and variable O&M costs assume ISO conditions and an 85 percent capacity factor. A more detailed breakdown of O&M costs is included in Section 2.3.2, and capital cost information for these options is included in Section 2.3.3.

Table 2-12
Pulverized Coal Unit Performance Characteristics (costs in $2004)

Condition	Construction Period (months)	Net Plant Heat Rate (Btu/kWh, HHV)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Subcritical PC Units				
250 MW PC	36	9,976	$29.84	$1.96
500 MW PC	44	9,756	$22.93	$1.82
500 MW PC, high sulfur coal	44	9,560	$24.36	$3.45
Supercritical PC Units				
500 MW	44	9,590	$22.30	$1.86
500 MW, high sulfur	44	9,398	$23.87	$3.46
750 MW	49	9,383	$19.12	$1.88
750 MW, high sulfur	49	9,195	$20.60	$3.49

2.3.2 Basis for O&M Estimates

The O&M summaries for the pulverized coal technologies are derived from more detailed estimates developed by Black & Veatch, based on vendor estimates and recommendations, actual performance information gathered from units in-service, and representative costs for staffing, materials, and supplies. The more detailed O&M estimates are shown in Table 2-13. These estimates are based on the unit ISO ratings and calculations assume an 85 percent capacity factor. High sulfur O&M estimates assume 4.5 percent sulfur content.

Table 2-13
Pulverized Coal O&M Costs (in $2004)

Category	250 MW Subcritical	500 MW Subcritical	500 MW Subcritical High Sulfur Coal	500 MW Supercricital	500 MW Supercricital High Sulfur Coal	750 MW Supercritical	750 MW Supercritical High Sulfur Coal
Station staffing assumptions	53	62	62	62	62	65	72
Fixed Costs ($1,000)							
Labor							
Operations	$1,581	$1,962	$2,107	$1,817	$1,962	$1,817	$2,155
Maintenance	$1,495	$1,856	$2,005	$1,708	$1,856	$1,862	$2,016
Technical Services	$480	$648	$648	$648	$648	$736	$736
Administration	$462	$462	$462	$462	$462	$462	$462
Labor Sub-Total	***$4,018***	***$4,928***	***$5,222***	***$4,634***	***$4,928***	***$4,877***	***$5,369***
Maintenance							
Boiler	$347	$689	$635	$689	$698	$939	$939
Turbine	$95	$188	$190	$188	$190	$282	$282
Ash handling	$101	$201	$203	$201	$203	$300	$300
Fuel handling	$76	$150	$152	$150	$152	$225	$225
Water treatment facilities	$32	$63	$63	$75	$76	$113	$113
Waste water treatment	$25	$50	$51	$50	$51	$75	$75
FGD Plant	$76	$150	$533	$150	$533	$225	$788
SCR and associated systems	$32	$63	$63	$63	$63	$94	$94
Particulate Control System	$50	$100	$102	$100	$102	$150	$150
Misc. & BOP steam plant	$62	$123	$124	$123	$124	$184	$184
Contract labor & Services	$378	$752	$762	$752	$762	$1,127	$1,127
Maintenance Sub-Total	***$1,274***	***$2,529***	***$2,878***	***$2,541***	***$2,954***	***$3,714***	***$4,277***
Other Expenses							
Property Taxes	$543	$1,081	$1,095	$1,081	$1,095	$1,620	$1,620
Office and Administrative Expenses	$402	$493	$522	$463	$493	$488	$537
Insurance	$1,223	$2,432	$2,463	$2,432	$2,463	$3,645	$3,645
Other Fixed Expenses Sub-total	***$2,168***	***$4,006***	***$4,080***	***$3,977***	***$4,051***	***$5,753***	***$5,802***
Total Fixed Costs	**$7,460**	**$11,463**	**$12,180**	**$11,152**	**$11,933**	**$14,343**	**$15,448**

Table 2-13
Pulverized Coal O&M Costs (in $2004)

Category	250 MW Subcritical	500 MW Subcritical	500 MW Subcritical High Sulfur Coal	500 MW Supercricital	500 MW Supercricital High Sulfur Coal	750 MW Supercritical	750 MW Supercritical High Sulfur Coal
Variable Costs ($1,000)							
Outage maintenance							
Turbine (Annualized)	$250	$250	$250	$300	$300	$400	$400
Boiler (Annualized)	$136	$270	$274	$338	$342	$506	$506
Balance of unit (Annualized)	$167	$332	$336	$332	$336	$497	$497
Outage maintenance Sub-total	***$553***	***$852***	***$860***	***$969***	***$978***	***$1,403***	***$1,403***
Water	$265	$526	$533	$526	$533	$789	$789
Chemicals							
Boiler	$189	$376	$381	$470	$476	$704	$704
Cooling tower	$353	$702	$711	$702	$711	$1,052	$1,052
Ash and FGD by-product disposal	$510	$955	$4,308	$932	$4,208	$1,452	$6,486
Desulfurization Equipment							
Limestone (wet Scrubber)	$0	$0	$3,322	$0	$3,245	$0	$5,002
Lime Reagent (dry scrubbers)	$839	$1,571	$0	$1,533	$0	$2,387	$0
Particulate Removal							
Bag Replacement (Annualized)	$200	$400	$1,200	$400	$1,200	$600	$1,800
ESP Overhaul (annualized)	$0	$0	$0	$0	$0	$0	$0
Selective Catalytic Reduction (assuming full year operation)							
Reagent Consumption (Ammonia)	$59	$110	$216	$107	$211	$167	$325
Catalyst replacement	$627	$1,247	$1,263	$1,247	$1,263	$1,868	$1,868
Grid tuning & slip testing	$50	$50	$50	$50	$50	$50	$50
Total Variable Costs	**$3,645**	**$6,788**	**$12,844**	**$6,937**	**$12,874**	**$10,472**	**$19,479**
Total O&M Costs	**$11,105**	**$18,252**	**$25,024**	**$18,089**	**$24,807**	**$24,815**	**$34,927**
Annual Net Generation (MWh)	1,861,500	3,723,000	3,723,000	3,723,000	3,723,000	5,584,500	5,584,500
Fixed Costs per net unit of capacity	**$29.84**	**$22.93**	**$24.36**	**$22.30**	**$23.87**	**$19.12**	**$20.60**
Variable Costs per unit of output	**$1.96**	**$1.82**	**$3.45**	**$1.86**	**$3.46**	**$1.88**	**$3.49**

Fixed O&M costs assume the units are at a Greenfield site. Plant staffing is assumed to provide operating and routine maintenance. Additional maintenance related to periodic overhauls and major inspections are assumed to be provided through maintenance contracts or contract services. These outage maintenance costs, though occurring periodically, depending on hours of operation and number of starts, have been annualized in the outage maintenance cost category.

2.3.3 Pulverized Coal Capital Costs

Capital cost estimates for the pulverized coal configurations are summarized in the Table 2-14. The following assumptions apply to the base plant cost estimates for pulverized coal generation facilities capable of 250 MW, 500 MW, and 750 MW net output.

2.3.3.1 General Assumptions for the Total Plant Cost Estimate

The Total Plant Cost is estimated in this section. The sum of the Total Plant Cost and the Owner's Cost equals the Total Project Cost or the Total Capital Requirement for the Project. Typically, the base plant is defined as being within the fence boundary with distinct terminal points. Plant facilities and systems outside the fence include the following which are typically included in the Owner's cost estimate:

Access road
Railroad
Gas supply and water supply pipelines
Transmission lines
Substation

The assumptions made for the Total Plant Cost include the following:

1. The plant cost estimate is based on a composite labor rate for the Louisville, Kentucky area of $31/hour.
2. The unit will be constructed at a Greenfield site in a rural area. The site will be a single unit site, level and without wetlands, and will be cleared of existing structures and underground obstructions by the Owner. The estimate does not include any demolition expenses.
3. The site has sufficient area available to accommodate construction activities including, but not limited to, temporary offices, parking, laydown, and staging.
4. The unit will feature one (1) steam generator and one (1) condensing steam turbine generator (STG). Draft fans and breeching equipment are included in

Table 2-14
Capital Costs for Pulverized Coal Units (in $2004)

Description	250 MW Subcritical PC	500 MW Subcritical PC	500 MW Subcritical PC, High Sulfur Coal	500 MW Supercritical PC	500 MW Supercritical PC, High Sulfur Coal	750 MW Supercritical PC	750 MW Super Critical PC, High Sulfur
Purchase Contracts:	**($1,000)**	**($1,000)**	**($1,000)**	**($1,000)**	**($1,000)**	**($1,000)**	**($1,000)**
Civil / Structural	$47,486	$84,105	$85,976	$88,390	$91,294	$114,475	$119,825
Mechanical	$27,081	$53,114	$54,032	$57,086	$58,667	$72,128	$6,631
Steam generator	$39,689	$59,600	$59,510	$64,298	$64,941	$89,600	$94,452
Steam turbine	$19,939	$29,442	$29,398	$32,268	$32,591	$42,000	$45,900
Air Quality Control System	$26,378	$31,935	$44,368	$32,144	$45,090	$41,787	$45,683
Electrical	$16,072	$25,236	$28,193	$25,463	$28,748	$33,309	$37,035
Control	$2,796	$4,135	$5,127	$4,172	$5,224	$5,424	$8,592
Chemical	$1,439	$2,287	$2,287	$3,136	$3,136	$4,077	$7,218
Subtotal Purchase Contracts:	**$180,879**	**$289,852**	**$308,891**	**$306,959**	**$329,692**	**$402,800**	**$435,336**
Construction Contracts:							
Civil / Structural Construction	$38,033	$74,905	$76,789	$74,316	$75,935	$111,474	$114,474
Mechanical / Chemical Construction	$65,457	$101,270	$106,110	$104,648	$109,099	$156,971	$164,471
Electrical / Control Construction	$10,097	$18,000	$20,969	$17,832	$20,728	$24,645	$29,145
Service Contracts & Construction Indirects	$40,439	$64,548	$65,450	$64,735	$65,406	$86,284	$87,784
Subtotal Construction Contracts:	**$154,025**	**$258,723**	**$269,318**	**$261,531**	**$271,169**	**$379,375**	**$395,875**
Total Direct Costs	**$334,904**	**$548,574**	**$578,209**	**$568,490**	**$600,861**	**$782,175**	**$831,211**
Indirect Costs:							
Engineering Costs	$28,600	$41,800	$44,987	$41,800	$43,890	$49,500	$51,975
Construction Management	$28,382	$33,391	$35,937	$33,931	$35,060	$37,626	$39,507
Startup Spare Parts	$848	$1,309	$1,348	$1,373	$1,400	$1,537	$1,691
Construction Utilities (Power & Water)	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner
Project Insurance	$2,247	$3,735	$3,793	$3,810	$3,850	$4,952	$5,448
Project Contingency	$8,882	$15,897	$20,097	$21,412	$25,129	$32,118	$33,724
Total Indirect Costs	**$68,958**	**$96,131**	**$106,162**	**$101,785**	**$109,330**	**$125,733**	**$132,244**
Total Contracted Costs:	**$403,863**	**$644,705**	**$684,372**	**$670,275**	**$710,190**	**$907,908**	**$963,555**
Escalation – Not Included	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner
Owner Costs – Not Included	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner
Total Capital Requirements:	**$403,863**	**$644,705**	**$684,372**	**$670,275**	**$710,190**	**$907,908**	**$963,555**
Net Plant Output, MW	250	500	500	500	500	750	750
Specific Capital Cost, $/kW	**$1,615**	**$1,289**	**$1,369**	**$1,341**	**$1,420**	**$1,211**	**$1,285**

these estimates. An allowance for structural steel is provided for the steam generator.

5. The steam generator will be a either a subcritical or supercritical pressure pulverized coal steam generator and will be enclosed in a building.
6. The subcritical steam generator will be a drum type, balanced draft, single reheat unit firing pulverized Powder River Basin (PRB) coal. Ignition fuel will be No. 2 fuel oil.
7. Steam soot blowers are assumed. One spare in-place pulverizer is included. Two 100 percent forced draft and primary air fans are included.
8. The supercritical steam generator will be a once-through, balanced draft, single reheat unit firing pulverized PRB coal. Ignition fuel will be No. 2 fuel oil. Steam soot blowers are assumed. One spare in-place pulverizer is included. Two 100 percent forced draft and primary air fans are included.
9. The STG will be rated at approximately 250, 500 or 750 MW (net) and includes a standard sound enclosure. The STG will be housed in an engineered generation building that includes a control room, electrical equipment room, battery room, motor control center and switchgear room and various offices.
10. Spread footings are assumed for all foundations except for major foundations (turbine and boiler area) which have an allowance for pilings.
11. The estimate includes an administration building, water treatment/fire pump building, warehouse/maintenance building. All buildings will be pre-engineered metal structures.
12. The cost estimate includes allowances for air emission control systems including selective catalytic reduction (SCR) to control NOx emissions, a fabric filter for control of particulate emissions, and a semi dry, lime, spray dryer absorber (SDA) to control SO2 emissions. An adder for a wet limestone FGD system is discussed in the following section.
13. Surface water will be supplied from a nearby lake or river. A raw water pump station and ponds for raw water storage (5-day storage capacity) and for rain water retention will be required. The cost of these facilities is included in the Owner's costs.
14. The estimate includes an on-site water treatment system. This system includes a raw water pretreatment (clarifier/softener) system followed by Reverse Osmosis (RO) and a demineralization system. The site specific water quality must be considered in selection and design of the actual water treatment system.

15. Potable water will be treated RO product water. Drinking water will be bottled water.
16. The estimate includes standard wastewater treatment methods such as neutralization, oil/water separation, sedimentation.
17. An on-site sanitary waste treatment system has been included in the estimate.
18. Construction power is assumed to be available at the site boundary.
19. Coal will be delivered to the site by rail. The coal handling system conveyors are included along with a crusher tower and a transfer tower, and a dust collection system.
20. It is assumed that the coal is Powder River Basin (PRB) coal. This is a low sulfur coal that will likely only require a semi dry lime spray dryer absorber FGD system or similar system. If the coal has higher sulfur then a FGD system capable of higher SO2 removal capability could be required. This system could be a wet limestone FGD system.
21. Limestone for use in a wet FGD system (if used) will be delivered to the site by train or trucks. Lime for use in a semi-dry SDA FGD system (if used) will be delivered to the site by self unloading trucks.
22. Fuel oil will be used during start up and for low load flame stabilization, if needed. Fuel oil is delivered to the plant via truck.
23. Automatic fire protection will include fire suppression systems, water deluge of the transformers, hydrant protection of the cooling tower and site, wet pipe sprinkler system in the buildings except in the control room which will have fire detection equipment only.
24. Field erected tanks will consist of the following:
    - Raw water storage tank
    - Demineralized water storage tank
    - Fuel oil storage tank
25. The cooling water system will consist of two circulating water pumps and a wet mechanical draft-cooling tower.
26. Firewater will be supplied from the cooling tower basin or the raw water storage tank, as required.
27. The stack is assumed to be a 2.5 times the tallest structure.
28. Manufacturer's standard equipment will be utilized to the greatest extent possible.
29. Off-site work is not included in the base plant cost estimate. These costs are included in the Owner's cost estimates.

2.3.3.2 *Direct Cost Assumptions*

The Direct Cost Assumptions include the following:

1. All costs are expressed in July 2004 US dollars (overnight cost), with no forward escalation.
2. Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
3. It is assumed that there will be no shortage of available craftsmen during construction. No premiums or incentives are included. Durations and labor rates are based on a 50-hour workweek, with scheduled overtime.
4. An allowance for lost time resulting from inclement weather is included.
5. An allowance is included for spare parts during start-up.
6. Permitting and licensing are not included in this cost estimate.
7. Shipping is included in the cost estimate.

2.3.3.3 *Indirect Cost Assumptions*

Indirect cost assumptions for the pulverized coal units include the following:

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training and the electricity, water and fuel used by contractors during construction. All standard insurances are included.
2. Engineering and related services include A/E services.
3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums and other required labor related insurance. Telephone and other utility bills associated with construction are included.
4. An allowance is included to cover contingency.
5. Owner's costs in Table 1-2 are not included.

2.4 Circulating Fluidized Bed Units

The primary alternative to a pulverized coal boiler is a circulating fluidized-bed (CFB) boiler. In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water cooled membrane walls with specially designed air nozzles which distribute the air uniformly. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of nitrogen oxides (NO_x).

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and thus fluidizing air elutriates the particles through the combustion chamber to the U-beam separators at the furnace exit. The captured solids, including any unburned carbon and unutilized calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

One of the key and most recognized advantages of CFB technology is its ability to burn a wide variety of low grade fuels such as peat, coal wastes, sludges, municipal wastes, biomass, oil shales, and petroleum coke, in addition to any high grade coals. CFB's can be designed to burn these fuels individually or in combination, providing the end user with flexibility in choosing the best economic mix to minimize generation costs.

CFB's are also widely recognized as being inherently low in emissions. This is in large part due to the low combustion temperatures, which reduces thermal NOx formation, and the ability to introduce limestone directly into the furnace to control SO_2 emissions.

CFB technology has now matured to the point that operating plants have demonstrated availability comparable the most modern solid fuel fired plants. The high availability of CFB's is also widely recognized within the financial community and numerous plants have been financed through non-recourse financing. Almost all of the active international project finance banks have provided non-recourse financing for projects using CFB technology. Within the past several years, the credit rating agencies have included projects using CFB technology among those, which qualify for an investment grade rating.

2.4.1 Performance of Selected CFB Units

Estimates for CFB units having full load capacities of 250 MW and 500 MW were selected for this analysis. Summary performance information for the PC power generation technologies is shown in Table 2-15. The O&M costs are in 2004 dollars, and variable O&M costs assume an 85 percent capacity factor. A more detailed breakdown of O&M costs in Section 2.3.2 and capital cost information for these options in Section 2.3.3.

Table 2-15
CFB Unit Performance Characteristics (costs in $2004)

Condition	Construction Period (months)	Net Plant Heat Rate (Btu/kWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
250 MW CFB	36	10,034	$32.61	$1.97
500 MW CFB	40	9,812	$22.46	$1.91

2.4.2 Basis for CFB O&M Estimates

The O&M estimates for the two CFB units are derived from more detailed estimates developed by Black & Veatch, based on vendor estimates and recommendations, actual performance information gathered from units in-service, and representative costs for staffing, materials, and supplies. The more detailed O&M estimates are shown in Table 2-16. These estimates are based on the unit ISO ratings and calculations assume an 85 percent capacity factor.

Fixed O&M costs assume the units are at a Greenfield site. Plant staffing is assumed to provide operating and routine maintenance. Additional maintenance related to periodic overhauls and major inspections are assumed to be provided through maintenance contracts or contract services. These outage maintenance costs, though occurring periodically, depending on hours of operation and number of starts, have been annualized in the outage maintenance cost category.

2.4.3 CFB Capital Costs

The following assumptions apply to the 250 MW and 500 MW CFB base plant cost estimates. The CFB cost estimates are presented in Table 2-17.

Table 2-16
CFB O&M Costs (in $2004)

Category	250 MW Low Sulfur Coal	500 MW Low Sulfur Coal
Station Staffing Assumptions	59	59
Fixed Costs ($1,000)		
Labor		
Operations	$1,840	$1,840
Maintenance	$1,649	$1,649
Technical Services	$480	$480
Administration	$462	$462
Labor Sub-Total	***$4,431***	***$4,431***
Maintenance		
Boiler	$401	$828
Turbine	$96	$199
Ash handling	$128	$252
Fuel handling	$116	$227
Water treatment facilities	$32	$53
Waste water treatment	$26	$42
FGD Plant	$180	$371
Particulate Control System	$51	$106
Misc. & BOP steam plant	$63	$127
Contract labor & Services	$385	$795
Maintenance Sub-Total	***$1,478***	***$3,000***
Other Expenses		
Property Taxes	$554	$914
Office and Administrative Expenses	$443	$443
Insurance	$1,246	$2,443
Other Fixed Expenses Sub-total	***$2,243***	***$3,800***
Total Fixed Costs	**$8,151**	**$11,231**
Variable Costs ($1,000)		
Outage maintenance		
Turbine (Annualized)	$250	$250
Boiler (Annualized)	$166	$343
Balance of unit (Annualized)	$170	$351
Outage maintenance Sub-total	***$586***	***$943***
Water	$270	$556
Chemicals		
Boiler	$193	$397
Cooling tower	$360	$742
Ash and FGD by-product disposal	$961	$1,945
Desulfurization Equipment		
Limestone (wet Scrubber or CFB units)	$274	$555
Lime Reagent (dry scrubbers)	$103	$208
Particulate Removal		
Bag Replacement (Annualized)	$600	$1,100
ESP Overhaul (annualized)	$0	$0
Selective Non-Catalytic Reduction (SNCR)		
Reagent Consumption (Ammonia or Urea)	$295	$597
Catalyst replacement	$0	$0
Grid tuning & slip testing	$25	$50
Total Variable Costs	**$3,668**	**$7,094**
Total O&M Costs	**$11,819**	**$18,325**
Annual Net Generation (MWh)	1,861,500	3,723,000
Fixed Costs per net unit of capacity	**$32.61**	**$22.46**
Variable Costs per unit of output	**$1.97**	**$1.91**

Table 2-17
Capital Costs for CFB Units (in $2004)

Description	250 MW CFB	500 MW CFB
Purchase Contracts:	($000s)	($000s)
Civil / Structural	$57,486	$82,896
Mechanical	$110,286	$175,346
Electrical	$17,910	$27,247
Control	$3,309	$4,785
Chemical	$1,528	$2,415
Subtotal Purchase Contracts:	**$190,519**	**$292,688**
Construction Contracts:		
Civil / Structural Construction	$35,567	$77,440
Mechanical Construction	$71,349	$104,566
Electrical / Control Construction	$10,739	$18,178
Chemical Construction	$406	$655
Service Contracts & Construction Indirects	$40,872	$64,548
Subtotal Construction Contracts:	**$158,934**	**$265,386**
Total Direct Costs:	**$349,453**	**$558,074**
Indirect Costs:		
Engineering Costs	$28,600	$41,800
Construction Management	$28,382	$30,355
Startup Spare Parts	$848	$1,309
Construction Utilities	By Owner	By Owner
Project Insurance	$2,247	$3,735
Project Contingency	$8,882	$15,897
Total Indirect Costs:	**$68,959**	**$93,096**
Total Contracted Costs:	**$418,412**	**$651,170**
Escalation – Not Included	$0	$0
Owner Costs – Not Included	$0	$0
Total Capital Requirements:	**$418,412**	**$651,170**
Net Plant Output (ISO)	250	500
Specific Capital Cost, $/kW (ISO)	**1,674**	**1,302**

2.4.3.1 General Assumptions for the Total Plant Cost Estimate

The Total Plant Costs for the CFB units are estimated in this section. The sum of the Total Plant Cost and the Owner's Cost equals the Total Project Cost or the Total Capital Requirement for the Project. Typically, the base plant is defined as being within the fence boundary with distinct terminal points. Plant facilities and systems outside the fence include the following which are typically included in the Owner's cost estimate:

Access road
Railroad
Gas supply and water supply pipelines
Transmission lines
Substation

The assumptions made for the Total Plant Cost include the following:

1. The capital cost estimate is based on a \$31/hour composite, average, weighted wage rate for Louisville, Kentucky.
2. The unit will be constructed at a Greenfield site in a rural area. The site will be a single unit site, level and without wetlands, and will be cleared of existing structures and underground obstructions by the Owner. The estimate does not include any demolition.
3. The site has sufficient area available to accommodate construction activities including, but not limited to, temporary offices, parking, laydown, and staging.
4. The site will be in a rural area without city services (water, sewer, etc.)
5. The 250 MW unit will feature one steam generator and one condensing steam turbine generator (STG). The 500 MW unit will feature two steam generators, and one STG. Draft fans and breeching equipment are included in these estimates. An allowance for structural steel is provided for the steam generator. The steam generator will be a CFB steam generator and will be enclosed in a building.
6. The STG will be rated at approximately 250 MW and 500 MW (net) and includes a standard sound enclosure. The STG will be housed in an engineered generation building that includes a control room, electrical equipment room, battery room, motor control center and switchgear room and various offices.
7. Spread footings are assumed for all foundations except for major foundations (turbine and boiler area) which have an allowance for pilings.

8. The estimate includes an administration building, water treatment/fire pump building, warehouse/maintenance building. All buildings will be pre-engineered metal structures.
9. The cost estimate includes allowances for air emission control systems including selective non-catalytic reduction (SNCR) to control NOx emissions and a fabric filter for control of particulate emissions.
10. The source of water for the plant will be the local water district.
11. The estimate includes an on-site water treatment system. This system includes a pretreatment system and a demineralization system. The site specific water quality must be considered in selection and design of the actual water treatment system.
12. Potable water will be treated water.
13. The estimate includes standard wastewater treatment methods such as neutralization, oil/water separation, sedimentation.
14. A sanitary waste sewer system has been included in the estimate.
15. Construction power is assumed to be available at the site boundary.
16. Coal will be delivered to the site by rail. The coal handling system conveyors are included along with a crusher tower and a transfer tower, and a dust collection system.
17. It is assumed that the coal is Powder River Basin (PRB) coal.
18. Limestone will be delivered to the site by train or truck.
19. Fuel oil will be used during start up and for low load flame stabilization, if needed. Fuel oil is delivered to the plant via truck.
20. Automatic fire protection will include fire suppression systems, water deluge of the transformers, hydrant protection of the cooling tower and site, wet pipe sprinkler system in the buildings except in the control room which will have fire detection equipment only.
21. Field erected tanks will consist of the following:
    - Raw water storage tank
    - Demineralized water storage tank
    - Fuel oil storage tank
22. The cooling water system will consist of two circulating water pumps and a wet mechanical draft-cooling tower.
23. Firewater will be supplied from the cooling tower basin or the raw water storage tank, as required.
24. The stack is assumed to be a 2.5 times the tallest structure.

25. Manufacturer's standard equipment will be utilized to the greatest extent possible.
26. Off-site work is not included in the base plant cost estimate. These costs are included in the Owner's cost estimates.

2.4.3.2 Direct Cost Assumptions

1. All costs are expressed in July 2004 US dollars (overnight cost), with no forward escalation.
2. Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
3. It is assumed that there will be no shortage of available craftsmen during construction. No premiums or incentives are included. Durations and labor rates are based on a 50-hour workweek, with scheduled overtime.
4. An allowance for lost time resulting from inclement weather is included.
5. An allowance is included for spare parts during start-up.
6. Permitting and licensing are not included in this cost estimate.
7. Shipping is included in the cost estimate.

2.4.3.3 Indirect Cost Assumptions

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training and the electricity, water and fuel used by contractors during construction. All standard insurances are included.
2. Engineering and related services include A/E services.
3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums and other required labor related insurance. Telephone and other utility bills associated with construction are included.
4. An allowance is included that covers contingency.
5. Owner's costs from Table 1-2 are not included.

2.5 Reciprocating Engines

Reciprocating engines are well proven prime movers for electric generation, industrial processes, and many other applications. Reciprocating engines operate according to either an Otto or Diesel thermodynamic cycle, very much like a personal automobile. These cycles use similar mechanics to produce work, but differ in the way that they combust fuel.

Reciprocating engines contain multiple pistons that are individually attached by connecting rods to a single crankshaft. The other end of the pistons seal combustion chambers where fuel is burned. A mixture of fuel and air is injected into the combustion chamber and an explosion is caused. The explosion provides energy to force the pistons down and this linear motion is translated into angular rotation of the crankshaft by the connecting rods. The combustion chambers are vented and the piston pushes the exhaust gases out completing the full rotation of the crankshaft. The process is repeated and work is performed.

Reciprocating engine generator sets are commonly used for self-generation of power either for emergency backup or peak shaving. However, there is also a well established market for installation of generator sets as the primary power source for small power systems and isolated facilities that are located away from the transmission grid.

When used for power generation, medium speed engines (less than 1,000 rpm), are typically used since they are more efficient and have lower O&M costs than smaller higher speed machines. Efficiency rates for reciprocating engines are relatively constant from 100 to 50 percent load, they have excellent load following characteristics, and they can maintain guaranteed emission rates down to approximately 25 percent load, thus providing superior part-load performance. Typical startup times for larger reciprocating engines are on the order of 15 minutes. However, some engines can be configured to start up and be completely operational within 10 seconds for use as emergency backup power.

Spark ignition engines are designed to operate on gaseous fuels such as natural gas, propane, and waste gases from industrial processes. Compression ignition engines are designed to operate on liquid fuels such as diesel fuel oil and biodiesel. Because they have such flexibility, engine generators are well-suited for use as conventional or renewable power generation. Table 2-18 provides estimates of performance and costs for a reciprocating engine power station.

Table 2-18
Reciprocating Engine Technology Characteristics

Engine Type	Spark Ignition	Compression Ignition (Diesel)
Commercial Status	Commercial	Commercial
Performance		
Net Plant Capacity, kW	1-5,000	1-10,000
Net Plant Heat Rate, Btu/kWh	9,700	7,800
Capacity Factor, percent	30-70	30-70
Economics		
Capital Cost, $/kW	450-1,100	350-800
Variable O&M, $/MWh	15-25	15-25
Construction Period, months	3 - 6	3 - 6

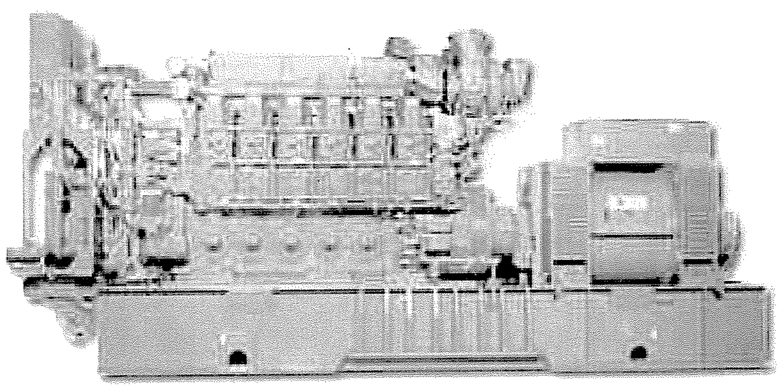


Figure 2-1. Engine Generator (Source: Caterpillar Corporation)

3.0 Renewable Energy Technologies

Renewable energy technologies are based on energy sources that are practically inexhaustible in that most are solar derivatives. Such technologies are sometimes favored by the public over conventional fossil fuel technologies because of the perception that renewable technologies are more environmentally benign, although this often comes at a cost premium. Renewable technologies evaluated in this section include wind, solar thermal, solar photovoltaic, biomass, geothermal, and hydroelectric technologies.

3.1 Wind

Wind power systems convert the movement of the air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade in percentage terms and has realized around 30 percent annual growth in worldwide capacity for the last five years. Cumulative worldwide wind capacity is now estimated to be more than 32,000 MW. Europe now leads in wind energy, with more than 20,000 MW installed; Germany, Denmark, and Spain are the leading European markets. Installations of wind turbines have outpaced all other energy technologies in Europe for the past two years.

In the US, the American Wind Energy Association (AWEA) has predicted that wind turbine capacity may exceed 6,000 MW by the end of 2003. The booming US wind market is driven by a combination of growing state mandates and the production tax credit (PTC), which provided a 10-year 1.8 cent/kWh incentive for electricity produced from wind. The PTC expired at the end of 2003 though various legislative efforts to reinstate the PTC are underway. Its long-term absence would severely dampen the US wind market.

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 0.10 MW to 2 MW. Wind energy system installations may total 5 to 300 MW, although single and small groupings of turbines are common in Denmark and Germany. Use of single smaller turbines is also increasingly common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, off-shore wind energy projects are now being planned, which is encouraging the development of both larger turbines (up to 5 MW) and larger wind farm sizes. Figure 3-1 shows a 9 MW wind farm near Sommerset, Pennsylvania.

Wind is an intermittent resource with average capacity factors ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly impacts economic performance, thus reasonably strong wind sites are a must for cost effective installations.

Figure 3-1. A 9 MW Wind Farm near Sommerset, Pennsylvania.

Because wind is intermittent it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this adds considerable expense and is not common. For larger wind farms numerous studies have shown that relatively low levels of wind grid penetration will not necessitate additional backup generation. Efforts are currently underway by research agencies to predict wind intensities more accurately, thereby increasing confidence in wind power as a generation resource and dependability in utility dispatching.

3.1.1 Cost and Performance Characteristics

Table 3-1 provides typical characteristics for a 50 MW wind farm and a single 600 kW turbine for distributed applications. Substantially higher costs are necessary for wind projects that require upgrades to transmission and distribution lines.

Capital costs for new onshore wind projects have remained relatively stable for the past few years. The greatest gains have been made by identifying and developing sites with better wind resources and improving turbine reliability. These both lead to improved capacity factors. The average capacity factor for all installed wind projects in the US has dramatically increased, from just 20 percent in 1998 to more than 30 percent in 2002.[1]

[1] Based on annual wind generation and capacity data from the Energy Information Administration's *Renewable Energy Annual 2002*.

Table 3-1 Wind Technology – Performance and Costs		
	Wind Farm	**Distributed**
Performance		
Net Plant Capacity, MW	50	0.6
Capacity Factor, percent	26 – 40	20 - 30
Construction Period, months	6	3
Economics		
Capital Cost, $/kW	1,000–1,800	1,800-2,600
Fixed O&M, $/kW-yr (Includes all O&M on $/kW basis)	30	35
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	6,352	

3.1.2 LGE Application

Wind energy is a mature renewable energy technology providing competitive power. Wind resource is rated as a function of strength and availability on a scale of Class 1 to Class 7, with Class 7 being high. By current technology standards, an area's wind resource needs to be rated at Class 3 or above in order to be economically feasible. The LGE service area has wind ratings of Class 1 and 2 as shown in the wind map of Figure 3-2. Because of this apparent level of wind resource, it seems as though a wind project is not viable for LGE.

3.2 Solar Thermal

Solar thermal technologies convert the sun's energy to productive use by capturing the heat from it. Early developments in solar thermal technology focused on heating water for domestic use. Advances have expanded the applications of solar thermal to high magnitude energy collection and power conversion on a utility scale. Numerous solar thermal technologies have been explored in the past two decades as potential sources of renewable power generation. The leading technologies currently include parabolic trough, parabolic dish, central receiver, and solar chimney. Figure 3-3 shows a central receiver installation and Figure 3-4 shows a parabolic dish receiver.

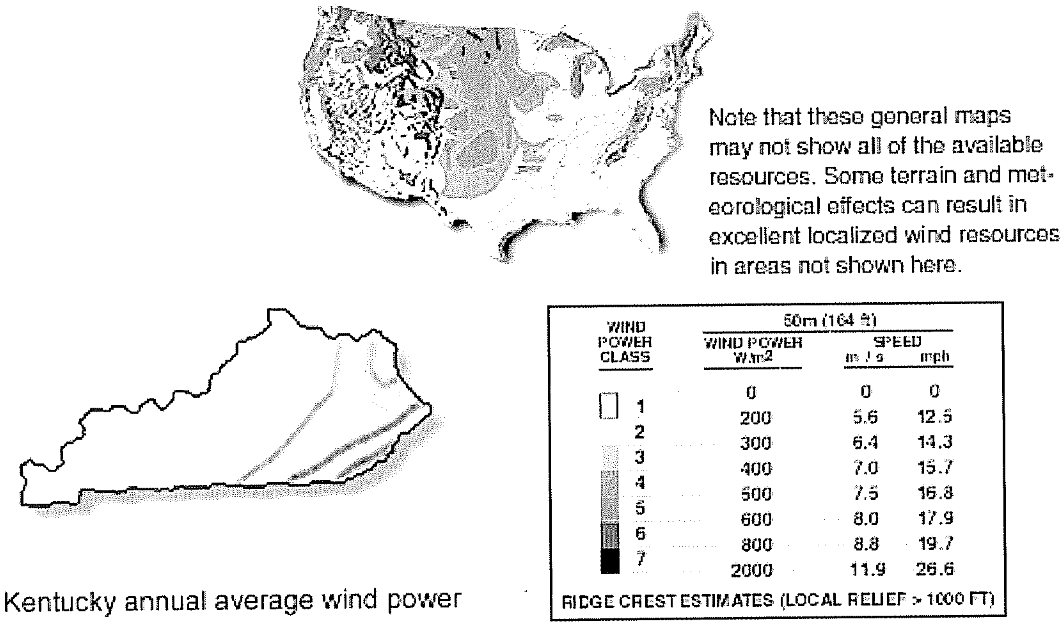


Figure 3-2. Kentucky Annual Average Wind Power
(Source:http://www.eren.doe.gov/state_energy/states_techresource.cfm?state=KY).

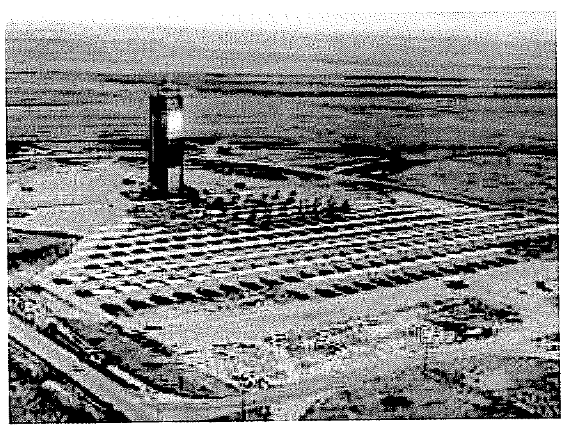


Figure 3-3. Central Receiver Installation.

Solar thermal technologies are appropriate for a wide range of intermediate and peak load applications including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in the US currently generate more than 350 MW.

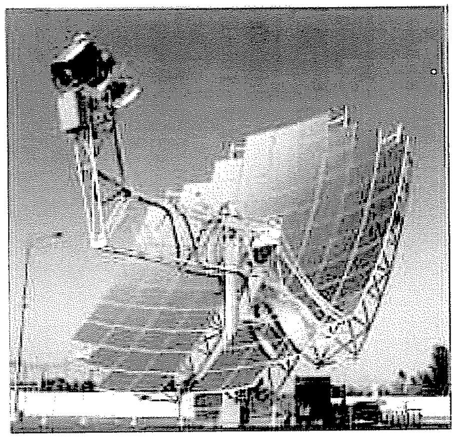


Figure 3-4. Parabolic Dish Receiver (Source: Stirling Energy Systems).

Solar thermal systems convert the heat in solar insolation to heat in a high temperature thermal energy carrier, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. Solar thermal technologies may be combined with co-utilization of fossil fuels or energy storage to provide a dependable dispatchable resource. Solar chimneys do not generate power using a thermal heat cycle as the other three technologies do. Instead, they generate and collect hot air in a large greenhouse. Located in the center of the greenhouse is a tall chimney. As the air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current, which rotates a collection of air turbines in the current. The first commercial solar chimney is currently under development in Australia.

The larger solar thermal technologies (parabolic trough, central receiver and solar chimney) are currently not economically competitive with other central station generation options (such as natural gas combined cycle). Parabolic dish engine systems are small and modular and can be placed at load sites, thereby directly offsetting retail electricity purchases. However, these systems are still under development and have not been used in commercial applications. Furthermore, significant advantages over quiet, more reliable PV systems are not evident.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the US desert southwest. The Global Environment Facility is currently investigating several integrated solar combined cycle projects that will likely make use of parabolic troughs as incremental solar capacity. Small parabolic dish engine systems have been developed by a few companies and are now being actively marketed. These systems are typically below 50 kW in size. The US government has funded two utility-scale central receiver power plants: Solar One and its successor/replacement, Solar

Two. Solar Two was a 10 MW installation near Barstow, California, but it is no longer operating due to reduced federal support and high operating costs.

Solar chimney technologies are receiving significant interest around the world. A project is proposed in Australia to build 200 MW solar chimney. The estimated cost is $700 million and would include a chimney one kilometer (0.62 mi) tall with an accompanying greenhouse 5 km (3.1 mi) in diameter.

In general, solar thermal potential is measured in terms of capacity for solar concentration. Concentrators can only gather direct sunlight for energy generation. Because of this, lower latitudes with minimum cloud cover offer the greatest solar concentrator potential. An advantage of solar thermal systems, and all solar technologies generally, is that peak output typically occurs on summer days when electrical demand is high.

3.2.1 Cost and Performance Characteristics

Representative characteristics for the four solar thermal power plant technologies are presented in Table 3-2.

Table 3-2
Solar Thermal Technology – Performance and Costs

	Parabolic Trough	Parabolic Dish	Central Receiver	Solar Chimney
Performance				
Net Plant Capacity, MW	100	1.2	50	200
Capacity Factor, percent	40 - 55	20 - 25	60 - 80	60 – 80
Construction Period, months	18 - 24	18 - 24	18 - 24	18 – 24
Economics				
Capital Cost, $/kW	4,000 - 5,000	3,000 - 4,000	5,000 - 7,000	3,500 – 4,500
Variable O&M, $/MWh (Includes all O&M on a $/MWh basis)	25 - 30	10 - 20	10 - 20	10 – 20
Technology Status				
Commercial Status	Commercial	Demonstration	R&D	R&D
Installed US Capacity, MW	~350	< 1	10*	< 1

Notes:
* No longer operating.

3.2.2 LGE Application

Solar thermal projects require large capital investment per kilowatt. To achieve maximum economic return, high capacity factors must be achieved. This is directly related to the amount of clear sky days at the facilities. As shown in Figure 3-5, LGE does not seem to be located in a geographical area likely to make a solar thermal project economical.

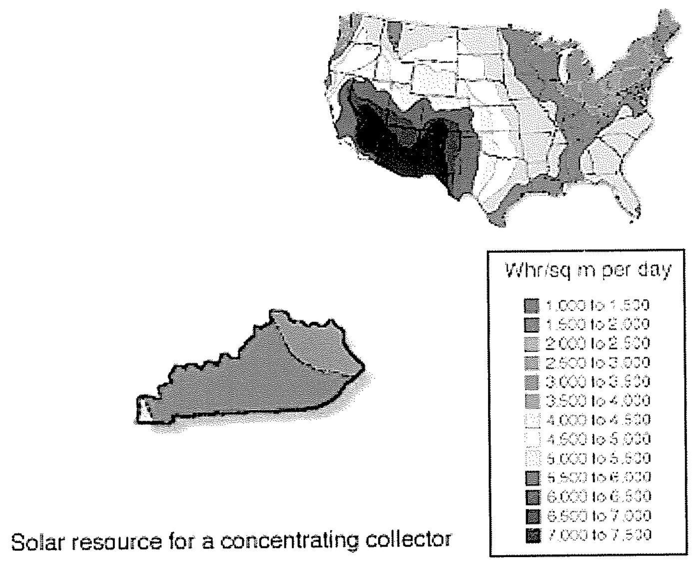


Figure 3-5. Map of Solar Resource for Concentrating Collector
(Source: http://www.eren.doe.gov/state_energy/states_techresource.cfm?stateKY).

3.3 Solar Photovoltaic

Photovoltaics (PV) have achieved much wider consumer acceptance over the last few years, and PV production tripled between 1999 and 2002. In 2002, worldwide photovoltaic cell and module manufacturing output rose to 562 MW. Worldwide grid-connected residential and commercial installations grew from 120 MW/yr in 2000 to nearly 270 MW/yr in 2002. The majority of these installations were in Japan and Germany. Large scale (>100 kW) photovoltaic installations have been added at a rate of about 5 MW per year over the last two years.[2]

Photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within the semiconductor material. To create a photovoltaic cell, a material such as silicon is doped (i.e., mixed) with atoms from an element with one more or one less electron than occurs in its matching substrate (e.g., silicon). A thin layer of each material is joined to form a junction. Photons striking the cell cause this

[2] Maycock, P., "PV market update", *Renewable Energy World*, July-August 2003.

mismatched electron to be dislodged, creating a current as it moves across the junction. The current is gathered through a grid of physical connections. Various currents and voltages can be supplied through series and parallel cell arrays. Figure 3-6 shows a typical PV solar panel installation.

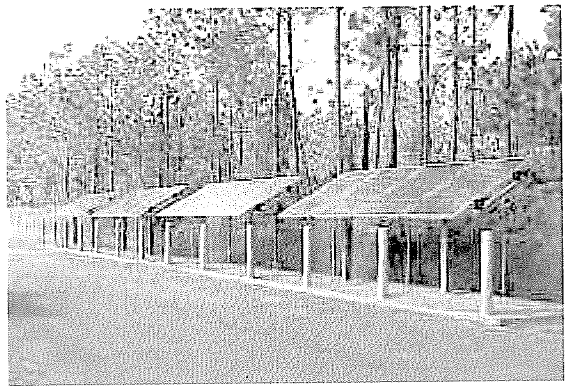


Figure 3-6. Photovoltaic Solar Panel Installation.

The DC current produced depends on the material involved and the intensity of the solar radiation incident on the cell. Single crystal silicon cells are most widely used today. The source silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. Polycrystalline cells are another alternative. These are inherently less efficient than single crystal solar cells but are less expensive to produce. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly.

Thin film cells are another type of photovoltaics that show great promise. Commercial thin films are principally made from amorphous silicon; however, copper indium diselenide and cadmium telluride also show promise as low-cost solar cells. Thin film solar cells require very little material and can be manufactured on a large scale. Furthermore, the fabricated cells can be flexibly sized and incorporated into building components.

The modularity, simple operation, and low maintenance requirements of solar photovoltaics makes them ideal for serving distributed, remote, and off-grid applications. Most PV applications are smaller than 1 kW. However, larger utility-scale installations are becoming more prevalent. Current grid-connected photovoltaic systems are generally below 200 kW. However, several larger projects ranging from 1 to 50 MW have been proposed. A 3.4 MW project is under construction in Arizona. This is one of the largest PV installations in the world. Most grid-connected PV applications require large subsidies (50 percent or more) to overcome inherently high initial costs.

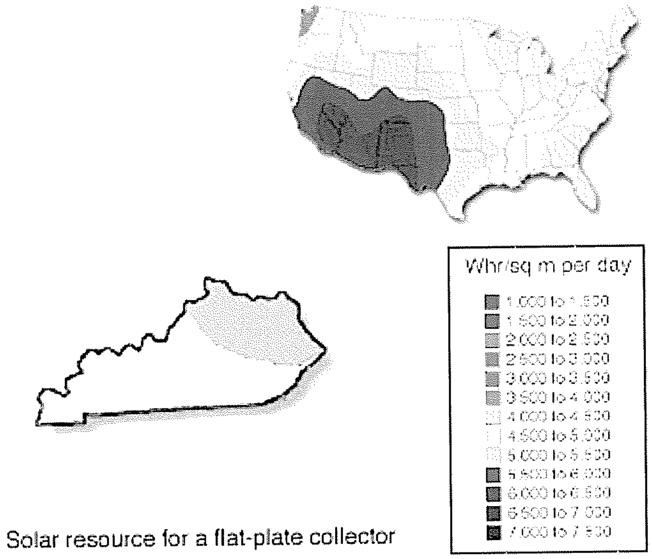
Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation. DNI, which comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. Diffuse insolation is that part of the radiation which has been scattered by the atmosphere or is reflected off the ground or other surfaces. All of the radiation on a cloudy day is diffuse. The vector sum of DNI and diffuse radiation is termed global insolation. Systems which concentrate solar energy use only DNI, while non-concentrating systems use global radiation. Most PV systems installed today are flat plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time.

Generally, stationary PV arrays will receive the highest average insolation if they are mounted at an angle equal to the latitude at which they are located. This configuration will give the highest year-round performance. To optimize performance for winter, the array may be tilted at an angle equal to the latitude plus 15 degrees. Conversely, for maximum output during summer months the array should be tilted at an angle equal to the latitude minus 15 degrees. Single and double axis tracking systems are also available that increase the system output, but at a significantly higher capital cost and increased O&M requirements. Cost and Performance Characteristics

Numerous variations in photovoltaic cells are available such as single crystalline silicon, polycrystalline, and thin films, and several support structures are available such as fixed-tilt, one-axis tracking, and two-axis tracking. For evaluation purposes, fixed-tilt, single crystalline photovoltaic system are characterized in Table 3-3. This technology is representative of most photovoltaic systems installed today. Two applications are characterized: a 4 kW residential system and a 50 kW commercial system.

3.3.1 LGE Application

As shown in Figure 3-7, Louisville may have an adequate solar resource for a PV project. Solar PV is an advancing technology that is being applied in many creative ways. Because there are so many ways to apply this technology, there are many capital cost estimates that could be anticipated. A realistic application might be the installation of multiple panel arrays on public buildings, such as schools. A 50 kW fixed-tilt system was assumed for the LGE application as shown in Table 3-3. Further analysis of the solar resource should be performed prior to advanced project planning.



Solar resource for a flat-plate collector

Figure 3-7. Solar Resource Map
(Source:http://www.eren.doe.gov/state_energy/states_techresource.cfm?state=KY).

Table 3-3
Solar Photovoltaic – Performance and Costs

	Residential	**Commercial or LGE**
	Performance	
Net Plant Capacity, kW	4	50
Capacity Factor, percent	18	20
Construction Period, months	1 - 3	1 - 3
	Economics	
Capital Cost, $/kW	8,500 – 12.500	7,500 – 9,500
Fixed O&M, $/kW-yr	45	20
Variable O&M, $/MWh	52	23
	Technology Status	
Commercial Status	Commercial	
Installed US Capacity (MW)	212	

3.4 Solid Biomass

Biomass is any material of recent biological origin. There is a huge variety of biomass resources, conversion technologies, and end products, as shown in Figure 3-8 below. This report focuses on electricity generation technologies. Electricity generation from biomass is the second most prolific source of renewable electricity generation after hydro. This section of the report describes solid biomass power options: direct fired biomass and cofired biomass.

Biomass Sources
- § Forests
  - Natural regrowth
  - Energy forests
  - Forest residues
  - Processing residues
- § Agriculture
  - Crop residues
  - Processing residues
  - Energy crops
- § Wastes
  - Municipal
  - Industrial

Processing
- § Drying
- § Extrusion
- § Compression
- § Chipping
- § Carbonization
- § Anaerobic digestion
- § Fermentation
- § Gasification
- § Pyrolysis
- § Fischer tropsch
- etc.processors

Fuel Products
- § Solid Fuels
  - Charcoal
  - Wood chips
  - Pellets/ briquettes
- § Gaseous fuels
  - Methane
  - Pyrolysis gas
  - Producer gas
- § Liquid fuels
  - Plant esters/oils
  - Ethanol
  - Methanol/alcohols
  - Pyrolysis liquids
  - Other liquids

Markets
- § Electricity
- § Heat
- § Solid fuels e.g.(domestic)
- § Transport

Source. Renewable Energy World, March-April 2003

Figure 3-8. Biomass Resources, Technologies, and End Products.

3.4.1 Direct Fired Biomass

According to the US Department of Energy (2002) there is currently 35,000 MW of installed biomass combustion capacity worldwide. The majority of this capacity is in the pulp and paper industry in combined heat and power systems.

Direct biomass combustion power plants in operation today essentially use the same steam Rankine cycle introduced into commercial use 100 years ago. By burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the biomass fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of biomass include spreader stoker-fired, suspension-fired, fluidized bed, cyclone and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are currently under development and are not considered for commercial applications in this study.

Wood is the most common biomass fuel. Other biomass fuels include agricultural residues, dried manure and sewage sludge, black liquor, and dedicated fuel crops such as switchgrass and coppiced willow. There are also many municipal waste burners installed throughout the world. However, the construction of new municipal waste combustion plants has become almost impossible in the US due to environmental concerns regarding toxic air emissions.

The capacity of biomass plants is usually less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. Furthermore, biomass plants will commonly have lower efficiencies compared to modern coal plants. The lower efficiency is due to the lower heating value and higher moisture content of the biomass fuel compared to coal. Additionally, biomass is typically more expensive and lower in density than coal. These factors usually limit use of direct fired biomass technology to inexpensive or waste biomass sources. Figure 3-9 shows a 35 MW biomass combustion power plant.

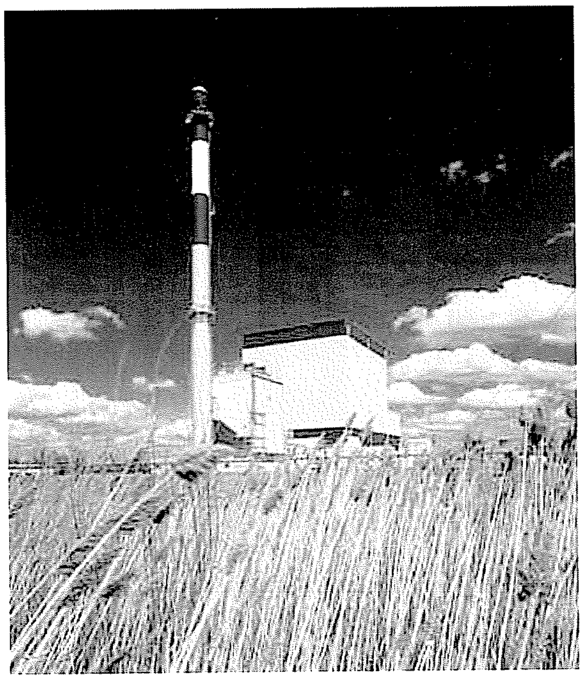


Figure 3-9. 35 MW Biomass Combustion Plant.

In addition to electrical generation, there are many industrial plants that burn their own biomass waste to produce thermal energy for heating and process applications. The small scale production of combined heat and power is seen as one of the more promising biomass applications.

Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest products industry activity. In rural areas the agricultural economy can produce significant fuel resources that may be collected and burned in biomass plants. These resources include corn stover, rice hulls, wheat straw, and other agricultural residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, a biomass project might burn wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Generally, availability of sufficient quantities of biomass is not as large of a concern as delivering the biomass to the power plant at a reasonable price.

3.4.1.1 Cost and Performance Characteristics

Table 3-4 provides typical characteristics of a 30 MW biomass plant using wood waste as fuel.

Table 3-4
Direct Biomass Combustion – Performance and Costs

	Commercial
Performance	
Net Plant Capacity, MW	30
Net Plant Heat Rate, Btu/kWh	14,500
Capacity Factor, percent	70 – 90
Construction Period, months	24 - 36
Economics	
Capital Cost, $/kW	2,000 – 2,500
Fixed O&M, $/kW-yr	60
Variable O&M, $/MWh	8
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	4,425*

Notes:
* Black & Veatch estimate for direct-fired plants only. Numerous plants also cofire biomass fuels, and these are not included in the estimate. See Table 3-5.

3.4.1.2 LGE Application

There are multiple biomass options open to LGE. These include a dedicated biomass burning plant, a co-fired biomass retrofit to an existing coal plant and a biomass cogeneration plant addition to an industrial feedstock generator, such as a pulp mill. A quick survey of the biomass resources in the LGE area indicates that wood is the most abundant resource and that it is most likely best applied as a co-firing feedstock. The economics of cofiring biomass are much more attractive as discussed in the biomass cofiring section.

3.4.2 Biomass Cofiring

An economical way to burn biomass is to cofire it with coal in existing plants. Cofired projects are usually implemented by retrofitting a biomass fuel feed system. A major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same basic power conversion technology but have much higher unit capacities, exceeding 1,000 MW. Due to their scale, modern coal plants are able to obtain higher efficiency at lower cost. Through cofiring, biomass can take advantage of this high efficiency at a more competitive cost than a stand-alone direct fired biomass plant.

There are several methods of biomass cofiring that could be employed for a project. The most appropriate system is a function of the biomass fuel properties and the coal boiler technology. Provided they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. Simply mixing the fuel into the coal pile may be sufficient.

Cyclone boilers and pulverized coal (PC) boilers (the most common in the utility industry) require smaller fuel size than stokers and fluidized beds and may necessitate additional processing of the biomass prior to combustion. There are two basic approaches to cofiring in this case. The first is to blend the fuels and feed them together to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, generally up to 10 percent of the coal heat input could be replaced with biomass using this method. The smaller fuel particle size of a PC plant limits the fuel replacement to perhaps 3 percent. Higher cofiring percentages (around 10 percent) in a PC unit can be accomplished by developing a separate biomass processing system at somewhat higher cost.

Even at these limited cofiring rates, plant owners have raised numerous concerns about negative impacts of cofiring on plant operations. These include:

- Negative impact on plant capacity
- Negative impact on boiler performance
- Ash contamination impacting ability to sell coal ash
- Increased operation and maintenance costs
- Limited potential to replace coal (generally accepted to be 10 percent on an energy basis)
- Minimal NOx reduction potential
- Boiler fouling/slagging due to high alkali in biomass ash
- Negative impacts on selective catalytic reduction air pollution control equipment (catalyst poisoning)

These concerns have been a major obstacle to more widespread biomass cofiring adoption. Most of these concerns can be addressed by using an external biomass gasifier to convert the energy of the solid biomass into a low energy gas ("syngas") to be fired in the boiler. Using gasification technology, it is expected that 25 percent or more of the coal heat input could be displaced without significant operational problems. Additionally, the syngas can be used as a reburn fuel to significantly reduce NO_x emissions. The gasification system has a higher cost than the other cofiring approaches, but still a fraction of the cost of a new direct-fired plant.

For viability, the coal plant should be within 100 miles of a suitable biomass resource. In the United States, which has the largest installed biomass power capacity in the world, biomass power plants provide 6,200 MW of power to the national power grid. Of the total electricity produced in 2001, coal accounted for 1.9 trillion kWh, or 51 percent. Conversion of as little as five per cent of this generation to biomass cofiring would nearly quadruple electricity production from biomass.

3.4.2.1 Cost and Performance Characteristics

Table 3-5 provides typical characteristics for a cofired plant using wood waste as fuel. If biomass fuel is available at a lower cost than the plant's coal supply, biomass cofiring could actually result in cost savings at the plant and a "negative cost" renewable energy resource.

Table 3-5
Cofired Biomass Technology – Performance and Costs

	Commercial or LGE
Performance	
Net Plant Capacity, MW	5 - 50
Net Plant Heat Rate, Btu/kWh	9,000 – 12,000
Capacity Factor, percent	50 - 90
Construction Period, months	12
Economics (Incremental Costs)	
Capital Cost, $/kW	50 - 600
Fixed O&M, $/kW-yr	5 - 20
Variable O&M, $/MWh	25-65
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	2,100*

Notes:
* Black & Veatch estimate for the biomass portion of plants that cofire coal and biomass. Actual capacity is unknown as the degree of cofiring varies substantially.

3.4.2.2 LGE Application

It is foreseeable that 5 - 50 MW of renewable energy could be reliably generated from cofiring of coal with biomass. Co-firing is most economically accomplished with a cyclone unit, but it can be adapted for use with a PC unit as well. Co-firing is not considered new generation. It will only offset fossil fuel consumption.

Utilities have tested co-firing biomass with coal and have demonstrated other advantages such as reduced emissions and fuel cost savings. Solid fuel co-firing up to 10 percent of the boiler heat input is practical without significant negative impacts tot he boiler system. Table 3-5 shows the performance and cost estimates of cofired biomass technology characteristics for LGE application.

3.5 Geothermal

Geothermal resources can provide energy for power production or a wide variety of direct use applications. Figure 3-10 shows a geothermal district heating equipment. Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. There are three basic types of geothermal technology: dry steam, flash steam, and binary cycle steam. Dry steam power plants are suitable where the geothermal steam is not mixed with water, and operate at high temperatures of between 356 - 662° F (180 - 350° C). Flash steam power plants tap into reservoirs of water with temperatures greater than 360° F (182° C). Binary cycle power plants operate on water at lower temperatures of 225 - 360° F (107 - 182° C).

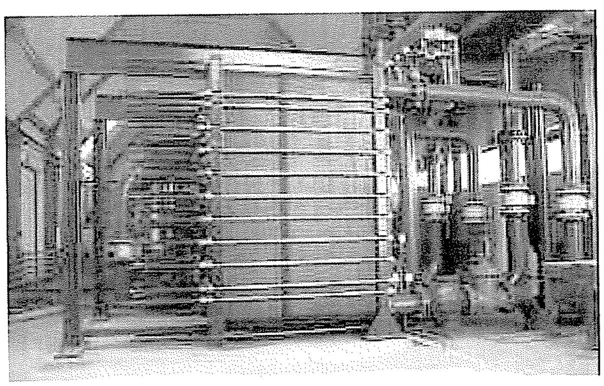


Figure 3-10. Geothermal District Heating Equipment.

As of 2002 the global installed capacity for geothermal power plants was 8,227 MW_e (megawatt electrical). An additional 15,580 MW_{th} (megawatt thermal) was used in direct heat applications. It is estimated that geothermal resources using today's technology could support between 35,500 and 72,000 MW_e of electrical generating capacity. Using enhanced technology that is currently under development (permeability enhancement, drilling improvements) geothermal resources have the potential to support between 65,500 and 138,000 MW_e.[3]

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications such as fish hatching, mushroom growing, refrigeration, washing and drying of wool, drying and curing of light aggregate cement slabs, evaporation in sugar refining, canning of food, drying of timber, and digestion of paper pulp.[4]

Geothermal power is limited to locations where geothermal pressure reserves are found. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installed. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating.

3.5.1 Cost and Performance Characteristics

For representative purposes, a binary cycle power plant is characterized in Table 3-6. Capital costs of geothermal facilities can vary widely as the drilling of individual wells can cost as much as four million dollars, and the number of wells drilled depends on the success of finding the resource.

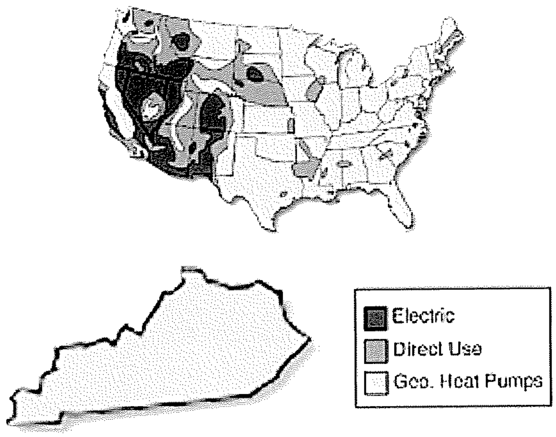
Table 3-6
Geothermal Technology – Performance and Costs

	Binary Cycle
Performance	
Net Plant Capacity, MW	30
Capacity Factor, percent	70 – 90
Construction Period, months	24 - 36
Economics	
Capital Cost, $/kW	2,500 – 4,000
Fixed O&M, $/kW-yr (Includes all O&M on $/kW basis)	200 – 300
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	2,216

[3] *Renewable Energy World*, 2002
[4] Geothermal Resources Council, 2003.

3.5.2 LGE Application

Geothermal resources for power generation are virtually non-existent in the LGE area as shown in Figure 3-11. Accordingly, no projects are suggested for this technology.



Kentucky geothermal resource

Figure 3-11. Map of Kentucky Geothermal Resource
(Source:http://www.eren.doe.gov/state_energy/states_techresource.cfm?state=KY).

3.6 Hydroelectric

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from one elevation to a lower elevation by passing it through a turbine. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Another method of capturing the kinetic energy is to divert the water out of the natural waterway, through a penstock and back to the waterway. This allows for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[5]

Hydroelectric projects are divided into a number of categories based upon their size. Micro hydro projects are below 100 kW. Systems between 100 kW and 1.5 MW are classified as mini hydro projects. Small hydro systems are between 1.5 and 30 MW. Figure 3-12 shows a small hydro power plant. Medium hydro is up to 100 MW, and large hydro projects are greater than 100 MW. Medium and large hydro are good resources for baseload power generation because they have the ability to store a large

[5] International Energy Agency, 2002.

amount of potential energy behind the dam and release it consistently throughout the year. Small hydro projects generally do not have large storage reservoirs and are not dependable as peaking resources.

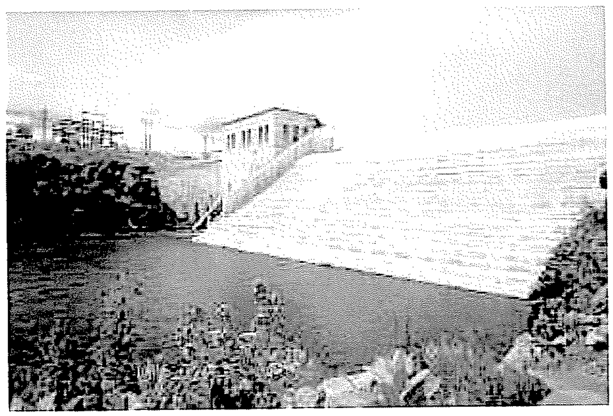


Figure 3-12. 3 MW Small Hydro Plant.

An especially attractive hydro resource is the upgrading and modernization of existing facilities, many of which were built more than 30 years ago. Such "incremental" hydro includes unit additions, capacity upgrades, and efficiency improvements.

Hydroelectric resource can generally be defined as any flow of water that can be used to capture the kinetic energy of its water. Projects that store large amounts of water behind a dam regulate the release of the water through turbines over time and generate electricity regardless of the season. These facilities are generally baseloaded. Pumped storage hydro plants pump water from a lower reservoir to a reservoir at a higher elevation where it is stored for release during peak electrical demand periods. Run-of-the-river projects do not impound the water, but instead divert a part or all of the current through a turbine to generate electricity. This technique is used at Niagara Falls to take advantage of the natural potential energy of the waterfall. Power generation at these projects varies with seasonal flows.

All hydro projects are susceptible to drought. In fact the variability in hydropower output is rather large. The aggregate capacity factor for all hydro plants in the US has ranged from a high of 47 percent to a low of 31 percent in just the last five years.[6]

[6] Energy Information Administration, *Renewable Energy Annual 2002.*

3.6.1 Cost and Performance Characteristics

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable; however, construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely.

Table 3-7 has ranges for performance and cost estimates for hydro projects for two categories: new projects at undeveloped sites and incremental hydro at existing sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions. To be able to predict specific performance and cost, site and river resource data would be required.

Table 3-7
Hydroelectric Technology – Performance and Costs

	New	**Incremental or LGE**
Performance		
Net Plant Capacity, MW	<50	1 - 160
Capacity Factor, percent	40 – 60	40 - 60
Construction Period, months	24 – 48	24 - 48
Economics		
Capital Cost, $/kW	2,500 – 4,500	600 – 3,000
Fixed O&M, $/kW-yr	5 – 25	5 - 25
Variable O&M, $/MWh	2.5 – 6	2 – 6
Technology Status		
Commercial Status	Commercial	Commercial
Installed US Capacity (MW)	79,842	NA

3.6.2 LGE Application

Hydroelectric is a mature renewable technology that can be applied in any location where the potential energy of water can be converted to kinetic energy and used to perform work. Kentucky has a strong history of hydro development. Hydro projects have extremely variable capital costs because there is not a "typical" installation. The addition of a hydro recovery unit in a pipeline may be very inexpensive, while the development of a new dam, reservoir and hydro facility may be very expensive. Costs vary depending upon size, geology, hydrology, existing transmission infrastructure and many other items. The performance and costs for a hydro project suitable for LGE application are shown in Table 3-7.

4.0 Waste to Energy Technologies

Waste to energy (WTE) technologies can utilize a variety of refuse types to produce electrical power. The use of municipal solid waste (MSW), refuse derived fuel (RDF), landfill gas (LFG) and tire derived fuel (TDF) to generate power will be addressed in this section. Economic feasibility of WTE facilities is generally difficult to assess. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. Values given in this section should be considered representative of the technology at a generic site.

4.1 Municipal Solid Waste

Waste to energy facilities operating on mass burning of municipal solid waste were seen in the 1980s as an environmentally sound and cost effective method of handling the problem of diminishing available landfill space in the US. However, as concerns about environmental pollutants (particularly dioxin) from the plants have risen, opposition to new projects has become increasingly effective. In addition, costs for MSW facilities have often exceed initial estimates, and communities are left paying for the plants for years. Within the past five years, only one new MSW facility has come online. That project retrofitted an existing incinerator to include a generator for power production. Figure 4-1 shows an MSW burning power plant.

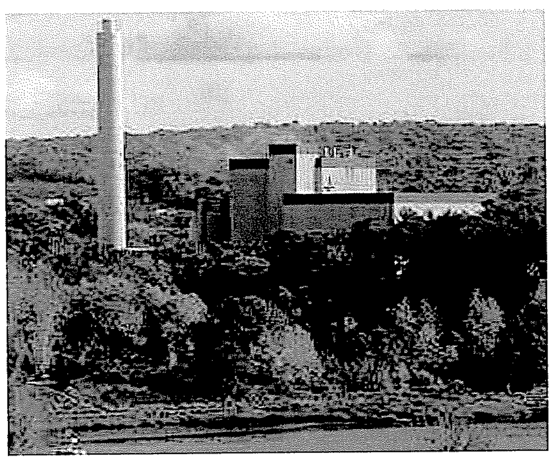


Figure 4-1. MSW Power Plant

(Source: UAE Energy Operations Corp.).

The degree of refuse processing determines the method used to convert municipal solid waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove non-combustible and oversized items, the MSW is fed on to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. This is similar to coal and biomass furnaces. Other furnaces used in mass burning applications are refractory furnaces and rotary kiln furnaces, which use other means to transfer the heat to the steam cycle or add a mixing process to the combustion. For smaller modular units, controlled air furnaces, which utilize two-stage burning for more efficient combustion, can be used in mass burning applications.

Converting refuse or MSW to energy can be accomplished by a variety of technologies. These technologies have been developed and implemented as a means of reducing the quantity of municipal and agricultural solid waste. The avoided cost of disposal is a primary component in determining whether a waste to energy facility is economically feasible.

Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents). Resource availability is limited by access to landfills. Similar to biomass, the cost of fuel transportation is a primary factor in the economics of an MSW plant. MSW plants are high capital projects that require a cheap and abundant fuel source to operate profitably. New plants are usually not economically viable unless a high tipping fee can be secured.

The average American generates over 4.4 pounds of garbage per day.[7] According to the US Census Bureau, Stanislaus County has a population of just fewer than 447,000[8]. Using these statistics, it seems as though there would be around 1,000 tons per day of garbage generated by the county and delivered to the landfill. There is currently an MSW plant operated by Ogden Martin at Crow's Landing in Stanislaus County. It is likely that this facility is consuming a large majority of the available fuel in the county.

4.1.1 Cost and Performance Characteristics

Table 4-1 has typical ranges of performance and cost for a facility burning 2,000 tons of MSW per day.

4.1.2 LGE Application

As stated above, it seems unlikely that new MSW plants will be permitted and built in the US in the near term. Accordingly, this technology is not further considered for LGE.

[7]As accessed 3/29/02 at http://www.researchpaper.com/forums/Suggestion_Box/messages/172.html
[8] US Census 2000

Table 4-1
MSW Mass Burning Unit – Performance and Costs

Performance	
Net Plant Capacity, MW	7
Net Plant Heat Rate, Btu/kWh	17,500
MSW Tons per Day	300
Capacity Factor, percent	60 - 80
Construction Period, months	24 – 36
Economics	
Capital Cost, $/kW	5,000 – 7,000
Fixed O&M, $/kW-yr	250 – 350
Variable O&M, $/MWh	65 – 85
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	2,493*

Note:
* Includes both mass burn and refuse derived fuel plants.

4.2 Refuse Derived Fuel

Refuse derived fuel (RDF) is an evolution of MSW technology. Instead of burning the trash in its bulky native form, trash is processed and converted to fluff or pellets for ease of handling and improved combustibility.

To ensure a proper mix of fuel, trash is sorted to remove metals, hard plastics and other undesirable materials. The remaining "clean" trash is conveyed to a mulching facility that shreds the material into small pieces. These pieces are delivered as fuel to a combustor.

RDF is preferred in many refuse to energy applications because it can be combusted with technology traditionally used for coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxide and sulfur dioxide emissions. In all boiler types, the combustion temperature for MSW or RDF must be kept at a temperature less than 800 °F in order to minimize boiler tube degradation due to chlorine compounds in the flue gas.

4.2.1 Cost and Performance Characteristics

Table 4-2 has typical ranges for performance and costs for a 15 MW RDF facility.

Table 4-2
RDF Stoker-Fired Unit – Performance and Costs.

Performance	
Net Plant Capacity, MW	7
Net Plant Heat Rate, Btu/kWh	19,300
MSW Tons per Day	300
Capacity Factor, percent	60 - 80
Construction Period, months	24 – 36
Economics	
Capital Cost ($/kW)	7,000 - 9,000
Fixed O&M ($/kW-yr)	450 – 550
Variable O&M ($/MWh)	70 - 90
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	2,493*

Note:
* Includes both mass burn and refuse derived fuel plants.

4.2.2 LGE Applications

As with MSW, RDF is not considered further for LGE.

4.3 Landfill Gas

Landfills generate gas as a byproduct of the decomposition of their contents. This landfill gas (LFG) has a methane content between 45 and 55 percent and is considered to be an environmental risk. Political and public pressure is rising to reduce air and groundwater pollution and the risk of explosion associated with LFG. From an energy generation perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines or small gas turbines.

LFG was first used as a fuel in the late 1970s. Since then, there has been a steady development of the technology for its collection and use. LFG energy recovery is now regarded as one of the more mature and successful of the waste to energy technologies. There are more than 600 LFG energy recovery schemes in 20 countries. Figure 4-2 shows an LFG power plant.

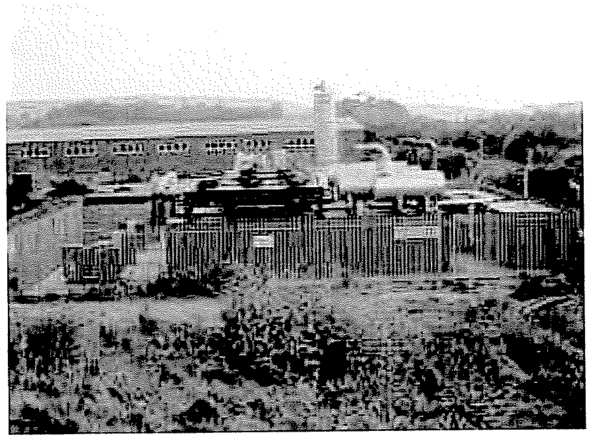


Figure 4-2. LFG Power Plant

(Source: CLP Envirogas Limited).

The EPA monitors landfill gas projects and opportunities at its Landfill Methane Outreach Program website at http://www.epa.gov/lmop/.

Landfill gas is produced by the decomposition of waste stored in landfills. This gas is flammable and can be collected and converted to electricity through various schemes. LFG may also be used directly for process heat or may be upgraded for pipeline sales. The major constituents released from landfill wells are carbon dioxide and methane.

Power production from LFG facilities is typically less than 10 MW. As discussed earlier, several types of conversion devices can be employed to generate electricity from LFG. Typically the equipment requires only minor modification so long as the gas is properly cleaned and prepared. Internal combustion engines are the most common generating technology choice.

Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine generator. Testing with microturbines and fuel cells is also underway.

Gas production in a landfill is dependent upon the depth of trash in place and amount of water received by the landfill. Each landfill is unique because each has a different volume, receives a different amount of water and has a different material composition. This variability makes it important to take measurements of quantity and quality of gas at a landfill before deciding to install a power generation system.

In general, LFG recovery may be economically feasible at sites that have over one million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and the equivalent of 25+ inches of annual precipitation. There are methods of changing both the quantity and quality of the LFG, if required, but doing so will affect the life span of the LFG supply. It is particularly important to understand that every landfill will reach a point in its life at which time the LFG production will decrease and eventually diminish below economically viable levels.

Many existing larger landfills have collection systems to remove leachate and LFG from the landfill to prevent it from infiltrating ground water supplies and causing other nuisance problems. These systems are usually connected to a flare system if there is not a power generation system installed. The flares combust the methane in the LFG. Such sites are attractive to LFG developers because the resource is generally well know and accessible.

4.3.1 Cost and Performance Characteristics

In some cases, the payback period of LFG energy facilities is between 2 and 5 years, especially when environmental credits are available and the gas collection system is already in place. Capital costs are dependent on the conversion technology and landfill characteristics, especially the presence of a gas collection system. The cost of installing a gas collection system at an existing landfill can be prohibitive. Performance and cost estimates for typical LFG projects using reciprocating engines are summarized in Table 4-3.

Table 4-3
Landfill Gas IC Engine – Performance and Costs.

	Commercial or LGE
Performance	
Net Plant Capacity, MW	0.2 – 15
Capacity Factor, percent	70 - 90
Construction Period, months	3 – 6
Economics	
Capital Cost, $/kW	1,300 – 2,700
Variable O&M, $/MWh (Includes all O&M on $/MWh basis)	15
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	1,100

4.3.2 LGE Application

LFG is a mature technology that can be applied with relative ease. Kentucky seems to have several newer, large landfills with long expected lifespan. These facilities would be good candidates for development. It is not possible to quantify how much power could be generated from one of these landfills without further analysis. However, it seems likely that a landfill could be found that has a gas collection in place and would only need to have the prime movers and gas treatment equipment added to it for power generation. Table 4-3 summarizes the costs and performance characteristics of an LFG power plant for LGE application.

4.4 Tire Derived Fuel

The conversion of used tires to energy via combustion is attractive due to the high heating value (15,000 - 17,000 Btu/lb), low ash and sulfur content, and low cost of tire derived fuel (TDF). The two major options for generating electricity from tires are co-firing with coal at an existing power station and dedicated tire combustion.

Recent experience with tire to energy plants is not good. A massive, toxic tire pile fire near Modesto, California, in 1999 put a dedicated tire burner out of business and has placed scrutiny on the industry. As a result, it is unlikely that new facilities using proven contemporary technology will be built. Although new technologies are under development, commercial systems are not yet offered. Figure 4-3 shows a TDF power plant.

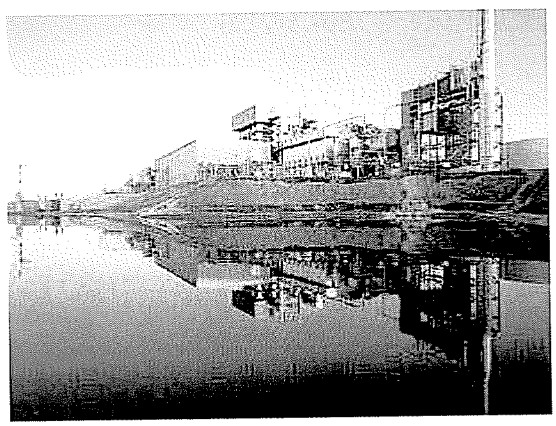


Figure 4-3. TDF Power Plant

(Source UAE Energy Operations Corp.).

Three major energy generation technologies have emerged for recovery of energy from tires:

- Combustion – complete oxidation (burning) of a fuel to release heat.

- Gasification – incomplete combustion of a fuel in a low oxygen environment to produce a combustible gas with a low to medium energy value.
- Pyrolysis – decomposition of a fuel by heat in the absence of oxygen to produce gas, oils, and char (carbon).

The major differentiator of these processes is exposure to oxygen. Pyrolysis occurs without oxygen, while combustion occurs with at least 100 percent of the amount theoretically required. Gasification occurs in between. Of these, combustion is the most proven application, with boiler designs for recovery of the heat conceptually similar to other combustion technologies.

The co-firing of TDF with coal or other fuels can be done in conventional boilers with little or no system modifications. Mixing 2 to 20 percent TDF in a co-firing application has been used in many utility boilers in the United States on a regular basis

Dedicated tire combustion systems are commercially available and are operating today. However, there have been numerous problems with these systems, largely due to the unique nature of tire fuel and improper design decisions. Black & Veatch is aware of six 100 percent tire-fired power plants located in the United States and the United Kingdom. The plants range in size from about 12 to 25 MW. Most of the projects are able to accept whole tires. Natural gas or another fossil fuel is typically used to provide better control of furnace conditions and flame stability. Recovered steel and zinc are potential revenue sources in addition to power sales.

Because of the difficulties experienced with dedicated tire combustion systems, multi-fuel systems that co-fire tires with coal and other fuels are a preferred technical solution.

4.4.1 Cost and Performance Characteristics

The estimated cost and performance of a 20 MW dedicated tire combustor and a 100 MW multi-fuel (10 percent TDF co-fire) circulating fluidized bed system are shown in Table 4-4.

4.4.2 LGE Application

This technology is similar to MSW and RDF in the sense that it is perceived poorly by the public and it is difficult to permit a dedicated tire burner. If LGE were interested in pursuing a TDF plant, a co-fired project would be the mostly likely candidate. Table 4-4 shows the cost and performance characteristics for a 50 MW TDF co-fired power plant for LGE application.

Table 4-4
Tire to Energy – Performance and Costs.

	100% TDF Fuel	10% TDF Co-fire	LGE
Performance			
Net Plant Capacity, MW	20	100	50
Net Plant Heat Rate, Btu/kWh	12,500	11,800 – 13,600	-*
Capacity Factor, percent	60 – 80	60 – 80	-*
Construction Period, months	24-36	12	
Economics			
Capital Cost, $/kW	3,500 - 5,500	1,800 – 2,530	2,500
Fixed O&M, $/kW-yr	80 - 120	40 – 75	60
Variable O&M, $/MWh	7 - 9	3 – 6.5	3
Technology Status			
Commercial Status	Early Commercial	Commercial	Commercial

Note:
* LGE to input the characteristics of its generation stations.

4.5 Sewage Sludge and Animal Waste Anaerobic Digestion

Anaerobic digestion is the naturally occurring process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct gas has 50 to 80 percent methane content. The most common applications of anaerobic digestion use industrial wastewater, animal manure, or human sewage. According to the European Network of Energy Agencies' ATLAS Project, the world wide deployment of anaerobic digestion in 1995 was approximately 6,300 MWth for agricultural and municipal wastes. This is estimated to increase to 20,130 MWth in 2010 with the majority of that growth being in municipal wastewater digestion.

Anaerobic digestion is commonly used in municipal wastewater treatment as a first stage treatment process for sewage sludge. Digesters are designed to convert the organic material or sewage sludge into safe and stable biosolids and methane gas. The use of anaerobic digestion technologies in wastewater treatment applications is increasing because it results in a smaller quantity of biosolids residue compared to aerobic technologies.

In agricultural applications, anaerobic digesters can be installed anywhere there is a clean, continuous source of manure. It is highly desirable that the animal manure be concentrated, which is common at dairy and hog farms. (Poultry litter is dryer and more suitable for direct combustion.) Dairy farms use different types of digesters depending upon the type of manure handling system in place at the farm and the land area available for the digester. A 600 to 700 head dairy farm generally produces sufficient manure to generate about 85 kW. Hog farms typically use simple lagoon digesters because of the wetter manure.

In addition to wastewater and agricultural residues, Los Angeles Department of Water has announced a new agreement to purchase power from a 40 MW anaerobic digestion facility that will process 3,000 tons per day of municipal green waste (such as landscape trimmings and food waste) to produce biogas for power production. The facility is scheduled to be on-line by 2009. This facility would be the largest of its kind in the world. There are various other high-solids digestions systems installed world wide. These are primarily in Europe and Japan and use municipal solid waste and green waste as feedstocks.

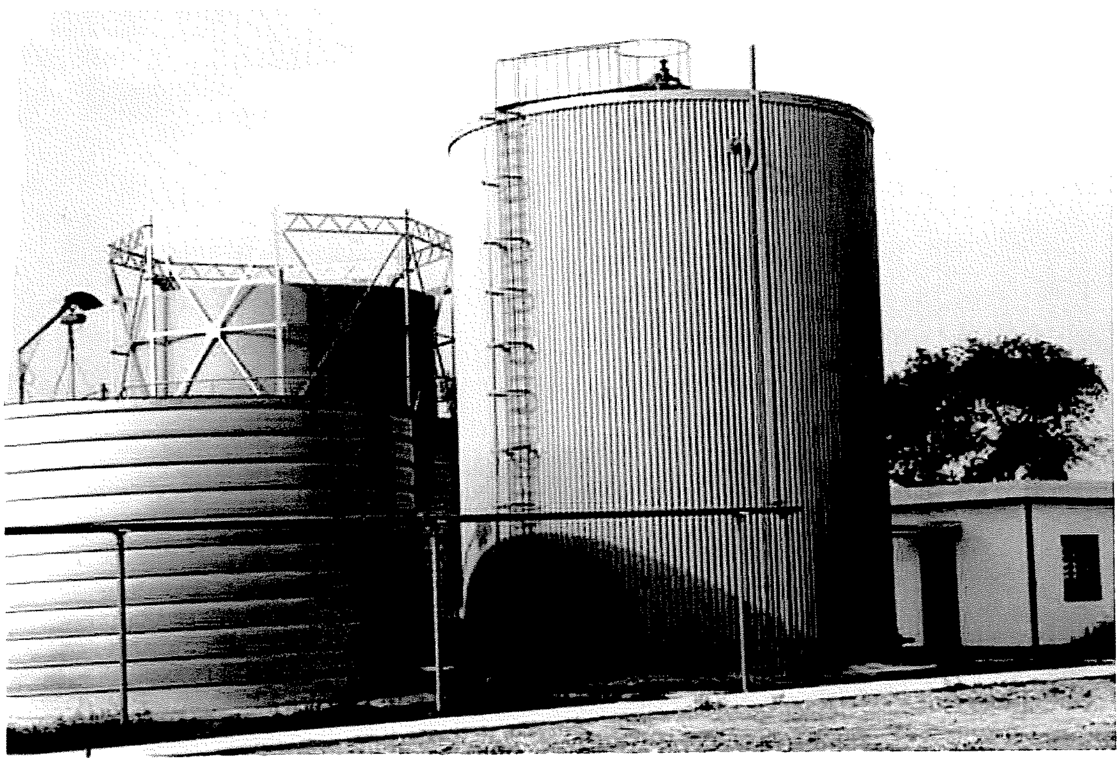


Figure 4-4. 500 m^3 Digester Treating Manure from a 10,000 Pig Farm in China.[9]

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and/or absorption chilling. Reciprocating engines are by far the most common power conversion device, although trials with microturbines and fuel cells are

[9] Image source: Perdue University, http://pasture.ecn.purdue.edu/~jiqin/PhotoDigester/PhotosDigesters.html.

underway. Agricultural digesters frequently satisfy the power demands for the farm on which they are installed, but do not provide significant exports to the grid. Municipal sewage sludge digesters produce enough gas to satisfy about half the wastewater treatment plant electrical load. Power production is typically a secondary consideration in digestion projects. Increasingly stringent agricultural manure and sewage sludge management regulations are the primary drivers.

For on-farm manure digestion, the resource is readily accessible and only some modifications are required to existing manure management techniques. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central, or regional digestion facility. For central plant digestion of manure from many farms, the availability of a large number of livestock operations within a close proximity is necessary to provide a sufficient flow of manure to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics because of high manure transportation costs. For anaerobic digestion of municipal sewage wastes the resource is readily available at the wastewater treatment plant.

4.5.1 Cost and Performance Characteristics

Table 4-5 provides typical characteristics of farm-scale dairy manure anaerobic digestion systems utilizing reciprocating engine technology.

Table 4-5
Anaerobic Digestion – Performance and Costs.

	Commercial or LGE
Performance	
Net Plant Capacity, MW	0.085
Capacity Factor, percent	70 - 90
Construction Pberiod, months	18 - 24
Economics	
Capital Cost ($/kW)	2,300 - 3,800
Variable O&M ($/MWh)	15
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity, MW_{th}	6,300

4.5.2 LGE Application

The LGE area contains a mid-range livestock population density. With this in mind, it is likely that farms could be found that are large enough to support power generation facility. If LGE were interested in pursuing this option, further research would be required to determine the best resource for manure. Estimates of performance and costs for an anaerobic digestion power plant for LGE application are summarized in Table 4-5.

5.0 Advanced Technologies

Advanced technologies include developmental and near commercial technologies that offer significant potential for cost and efficiency improvements over conventional technologies. These include advanced gas and coal technologies, fuel cells, and microturbines.

5.1 Advanced Gas Turbine Technologies

Combined cycle combustion turbines have many advantages including low capital cost, high efficiency, and short construction periods. Operation of an actual combustion turbine approaches that of an idealized thermodynamic cycle called the air-standard Brayton cycle. The Brayton cycle is based on an all gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle, which is a vapor-based cycle. Three Brayton cycles show promise as advanced technologies: the humid air cycle, Kalina cycle, and Cheng cycle.

5.1.1 Humid Air Cycle

The humid air turbine (HAT) cycle is an intercooled, regenerative cycle burning natural gas with a saturator that adds considerable moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Table 5-1 presents typical performance and cost characteristics for the HAT cycle.

5.1.1.1 LGE Application

Although the HAT cycle may offer future energy efficiencies and cost savings, it is a developmental technology that is not ready for commercial application. Accordingly, it is not considered further for LGE as a potential project.

Table 5-1
Humid Air Turbine Cycle – Performance and Costs

Commercial Status	Development	LGE
Construction Period, months	20-28	20-28
Performance		
Plant Capacity (MW)	250 - 650	not applicable, developmental
Net Plant Heat Rate (Btu/kWh)	6,500	
Capacity Factor (percent)	60 - 80	
Economics		
Capital Cost ($/kW)	425 – 635	
Fixed O&M ($/kW-yr)	5.30 - 9.50	
Variable O&M ($/MWh)	1.60 - 4.25	

5.1.2 Kalina Cycle

The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on the non-isothermal boiling and condensing behavior of the working fluid's two-component mixture, coupled with the ability to alter the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. Table 5-2 presents typical performance and cost characteristics for the Kalina cycle.

5.1.1.2 LGE Application

The Kalina cycle is just starting to become a commercially viable technology. There are currently four plants operating worldwide which use this technology. Capital costs still are high and power outputs are thus far limited to under 5 MW. The Kalina cycle could be retrofit to an existing plant or a gas compressor station to capture waste heat.

Table 5-2
Kalina Cycle – Performance and Costs

Commercial Status	Development	LGE
Construction Period (months)	26-29	29-29
Performance		
Plant Capacity (MW)	50 - 500	not applicable, developmental
Net Plant Heat Rate (Btu/kWh)	6,700	
Capacity Factor (percent)	60 - 80	
Economics		
Capital Cost ($/kW)	635 - 800	
Fixed O&M ($/kW-yr)	4.25 – 11	
Variable O&M ($/MWh)	1.60 - 4.25	

5.1.2 Cheng Cycle

The Cheng cycle, which is similar to the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and heat recovery steam generator (HRSG). The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration plant where increased power can be produced during low cogeneration demand and/or peak demand periods. Since 1984, over 50 small cogeneration plants have applied the Cheng cycle in California, Japan, Australia, and Europe. The Cheng cycle has also been proposed as a retrofit for simple cycle combustion turbines. Table 5-3 presents typical performance and cost characteristics for the Cheng cycle.

5.1.2.1 LGE Applications

While the Cheng cycle is not a commercially viable technology, some IPPs are actively pursuing this technology in the near term.

Table 5-3
Cheng Cycle – Performance and Costs

Commercial Status	Development (larger units)	LGE
Construction Period (months)	20-28	20-28
Performance		
Plant Capacity (MW)	25 - 250	not applicable, developmental
Net Plant Heat Rate (Btu/kWh)	8,000 - 9,000	
Capacity Factor (percent)	60 - 80	
Economics		
Capital Cost ($/kW)	740 - 1,170	
Fixed O&M ($/kW-yr)	6.35 – 11	
Variable O&M ($/MWh)	1.60 - 4.25	
Note: Assuming retrofit of existing facility.		

5.2 Pressurized Fluidized Bed Combustion

Coal fired plants continue to supply a large portion of the energy requirements in the US. Current research is focused on making the conversion of energy from coal more clean and efficient. Pressurized fluidized bed systems have been developed to improve coal conversion efficiency.

Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations, PFBC exhaust is expanded to drive both the compressor and gas turbine generator. Heat recovery steam generators transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. These second generation PFBC systems are in the development stage. Table 5-4 presents typical performance and cost characteristics for pressurized fluidized bed combustion.

5.2.1 LGE Application

Because this technology is also in the development stage, it is difficult to accurately quantify the capital costs. This technology is not yet mature enough to be considered for a new generation project.

Table 5-4
Pressurized Fluidized Bed Combustion – Performance and Costs

Commercial Status	Development	LGE
Construction Period (months)	32-38	32-38
Performance		
Plant Capacity (MW)	150 – 350	150 - 350
Net Plant Heat Rate (Btu/kWh)	8,000 - 9,000	8,000 - 9,000
Capacity Factor (percent)	60 – 80	60 - 80
Economics		
Capital Cost ($/kW)	1,430 - 1,950	1,430 - 1,950
Fixed O&M ($/kW-yr)	21 – 37	21 – 37
Variable O&M ($/MWh)	4.0 - 5.3	4.0 - 5.3

5.3 Integrated Gasification Combined Cycle

This section includes capital cost and performance information for a 250 MW and a 500 MW integrated gasification combined cycle (IGCC) plant located at a generic Greenfield site near Louisville, Kentucky. As IGCC technology is not as commercially mature and more complex than the technologies discussed previously, and the some of the information is presented in a format that differs from the other technologies.

5.3.1 Technology Description

The IGCC estimate assumes that the electric generating unit will use the Shell Coal Gasification Process. The nominal 250 MW unit will be a single train consisting of one air separation unit (ASU), one Shell coal gasifier, and a 1x1 combined cycle with a GE 7FA combustion turbine. The nominal 500 MW unit will be two gasifier trains (each train consisting of one ASU and one Shell coal gasifier) and a 2x1 combined cycle combustion turbine with two GE 7FA combustion turbines.

Powder River Basin coal is assumed for estimating purposes. The coal will be dried by circulating hot gas through a pulverizer. The dried, pulverized coal will be partially oxidized in the gasifier to produce raw syngas (synthetic gas produced by the process). The raw syngas will be treated to remove particulate, ammonia, and sulfur prior to combustion. The clean syngas will be diluted with nitrogen and water vapor to enhance combustion turbine efficiency and control NOx to less than 25 ppmv (dry at 15% O2) in the flue gas. Flyash, slag, and sulfur will be saleable byproducts from gasification. Wastewater treatment solids will be disposed of off site in an environmentally acceptable manner. Plant heat rejection will be provided by a wet cooling tower. Surface water will be supplied from an off-site source to the site boundary.

5.3.1.1 Project Scope and Assumptions

The project includes all site, plant, and other facilities required in connection with an electric generating unit, excluding the plant substation. The power termination point is at the high side of the step-up transformer. All site civil works, structures, equipment, auxiliaries and accessories, piping, raceway, wiring and controls, and other facilities required for the complete unit are included.

The project cost was developed based on the following assumptions.

- Soil is suitable for spread footings with no pilings.
- Land purchase is not included.
- Site is level, no rock excavation required, no trees, no dewatering, no underground obstruction, and no fill requirements. Cut and fill balance is on site.
- No hazardous and/or contaminated material will be encountered on site and no removal or replacement of soil is required.
- Land right-of-way and permits are excluded.
- No cooling tower plume abatement is included.
- Costs to comply with any special local noise requirements are not included.
- Startup and construction utilities such as water, power, fuel, and compressed gases are not included.
- Unlimited access to the project site is available.
- Suitable storage facilities/laydown areas are available immediately adjacent to the plant site.
- Construction to be performed on open shop basis.
- Cost for wetlands or threatened and endangered species impact mitigation are not included.
- Roadways are included only for area local to site. (An access road to the site is not included.)
- No landscaping costs except overseeding have been included.
- Costs for a site geotechnical and subsurface report are not included.
- Demolition or removal of any existing utilities, structures, etc. has not been included.
- First fills of chemicals, gases, fuel, and water storage tanks are not included.

- Costs for makeup water provisions are not included.
- Water termination point will be at site boundary.
- Number 2 fuel oil will be used for unit startup with no preheating required.
- Propane will be used for flare pilot fuel.
- No plant communication equipment is included.
- Plant dispatching and any special communications are not included.

Major facilities included are as follows.

- Onsite fencing, roads, and railroads.
- Construction facilities.
- Administrative offices, locker-shower-sanitary facilities, laboratories, and warehouse.
- Water management facilities including water supply and treatment, wastewater collection and treatment, and chemical storage equipment.
- Air Separation Unit
- Coal Milling System (with integral Coal Drying)
- Gasification System
- Syngas Treatment System (with Sulfur Recovery)
- Combustion Turbine/Steam Turbine and Generator. (indoors)
- Heat Recovery Steam generator. (outdoors)
- Air quality control equipment. (outdoors)
- Steam condensing equipment.
- Plant cooling equipment. (cooling tower)
- Service water supply and storage systems.
- Fire protection equipment.
- Coal unloading equipment (rapid bottom discharge bottom dump railcars), stacker/reclaimer, , and transport conveyor.
- 40 days on-site coal storage. (10 days active)
- Flux additive handling facilities.
- On-site byproduct storage
- On-site solid waste landfill provisions.
- Control and electrical equipment for protection and operation of the generating unit.

5.3.1.2 Site Description

The site includes the generating complex, air quality control equipment, water pretreatment and demineralization equipment, wastewater treatment equipment and evaporation ponds, and administration and warehouse facilities. On-site storage is included for slag, flyash, and sulfur byproducts and wastewater treatment solids. The site elevation is assumed to be 700 feet above MSL. The design ambient temperature is 76°F wet bulb. The site seismic rating is zone 1.

5.3.1.3 Fuel Supply

The fuel to be gasified by the new unit will be Wyoming Powder River Basin sub-bituminous coal with a higher heating value of 8,500 Btu per pound as-received. The as-received coal composition is assumed to be the following:

Moisture	29.35 percent by weight, as-received
Ash	5.05 percent by weight, as-received
Sulfur	0.3 percent by weight, as-received

The coal is assumed to be delivered to the site by rail and use rapid bottom dump hopper car unloading. Coal storage equivalent to 40 days of plant operation at design capacity is assumed. No. 2 fuel oil will be delivered by railcar or truck, and two 56,000 barrel capacity fuel oil storage tanks are assumed. Propane will be delivered by truck; and one 2,600 gallon propane tank is assumed.

5.3.2 Performance, Availability, and Emissions

Performance, availability, and emissions estimates for the 250 MW and 500 MW IGCC Units are presented in Table 5-5 assuming an 85 percent capacity factor. Unit performance is based on a site elevation of 700 feet above MSL and an ambient temperature of 59° F.

Dilution of the syngas with a large volume of nitrogen and water vapor results in constant gas turbine power output over varying ambient temperature. Plant auxiliary power consumption increases with ambient temperature (primarily ASU air compressor and cooling tower fan power). Therefore plant net power output decreases slightly with increasing ambient temperature.

Long term IGCC unit availability is expected to exceed 85 percent. Commercial IGCC unit availability has been much less primarily during the first several years of operation. Experience gained from coal IGCC plants that have been operating since the mid-1990s will allow new IGCC plants to have higher availabilities. Long term IGCC unit forced outage rates (FOR) are expected to range from 7 to 10 percent. The gas turbine(s) can operate on backup fuel when syngas is not available. The CC availability is expected to exceed 90 percent.

Table 5-5
IGCC Performance, Availability, and Emissions

Description	Single Train	Two Trains
Performance		
Coal to Gasifiers, as-received STPD[1]	3015	6030
Gasifier Cold Gas Efficiency - (Clean Syngas HHV/Coal HHVx100),%	83.1	83.1
Syngas to Gas Turbine(s), MBtu/hr (LHV)	1690	3380
Gas Turbine(s) Gross Power, MW	197	394
Steam Turbine Gross Power, MW	118	236
Total Gross Power, MW	315	630
Auxiliary Power Consumption & Losses, MW	48	96
Net Power, MW	267	534
IGCC Net Heat Rate, Coal - Btu/kWh (HHV)	8,500	8,500
Availability/Capacity Factor		
IGCC First Year of Operation, %	30-70	30-70
IGCC Second Year of Operation, %	40-80	40-80
IGCC Third Year of Operation, %	50-85	50-85
IGCC After Third Year of Operation, %	85	85
CC with Backup Fuel, %	90	90
Emissions at 100% Load		
CO_2, lb/MBtu [3]	212	212
CO, lb/MBtu [3]	0.05	0.05
SO_2, lb/MBtu [3]	0.014	0.014
NO_x, lb/MBtu [3]	0.05	0.05
Particulate, lb/MBtu [3]	0.013	0.013
Byproduct Sulfur, LTPD[2]	7	14
Byproduct Slag/Flyash, STPD[1]	175	350

Notes:
1. STPD = short tons per day
2. LTPD = long tons per day
3. Based on the higher heating value of as-received coal.

The CO and NOx emissions estimates are based on current GE guarantees for their 7FA gas turbines firing syngas with nitrogen dilution without SCR or CO oxidation catalyst in the HRSG:

25 ppmvd CO in the gas turbine exhaust gas

25 ppmvd NOx (at 15%v O2) in gas turbine exhaust gas

The SO_2 emissions estimate is based on 25 ppm molar concentration of sulfur as H_2S and COS in the syngas. Overall IGCC unit sulfur removal efficiency is 98 percent.

5.3.3 Capital Cost

Preliminary capital cost estimates for the 250 MW and 500 MW IGCC Units are presented in Table 5-6.

Table 5-6
Capital Cost Estimates for IGCC Units

Description	Single Train	Two Trains
Net Plant Capacity, MW	267	534
EPC Direct Cost, $ million	374	704
EPC Indirect Cost, $ million	66	119
EPC Total Cost, $ million	440	783
EPC Total Cost, $/kW net plant capacity	1,648	1,541

The capital costs are based on a typical EPC contract scope. Project scope assumptions are detailed in previous section of this report.

Direct Capital costs include:

- Equipment and materials
- Construction labor
- Capital spares
- Freight
- Commissioning

Indirect Capital costs include:

- Engineering including conceptual design and EPC Bid Specification
- Gasification Technology License
- Construction Management
- Insurance and Bonds for EPC Contractor

Capital costs include contingency for the EPC contractor. Owner's costs from Table 1-2 are excluded.

5.3.4 O&M Costs

Operating and maintenance cost estimates for the 250 MW and 500 MW IGCC Units are presented in Table 5-7.

Table 5-7
IGCC Non-fuel O&M Cost Estimates

Description	Single Train	Two Trains
Net Plant Capacity, MW	267	534
Long Term Plant Capacity Factor, %	85	85
Plant Staff	120	165
Plant Staff Expense, $ million/year	10.4	14.0
Fixed Operating Cost, $ million/year	12.6	17.2
Fixed Operating Cost, $/kW-yr	47.19	32.21
Variable Operating Cost, $ million/year	11.7	22.3
Variable Operating Cost, $/MWh	5.88	5.52
Capital O&M Cost, $ million/year	24.3	39.5
Total Non-fuel O&M Cost, $/MWh	12.22	9.93
Construction Schedule (months)	38	51

The variable and total O&M costs are based on a capacity factor of 85 percent. The operating costs assume the slag and flyash will be sold at a price that breaks even with its handling cost. The costs do not include the cost of coal, fuel oil, or propane.

5.4 Fuel Cells

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation for permanent power and intermittent power demands. Figure 5-1 shows an example of a fuel cell in operation.

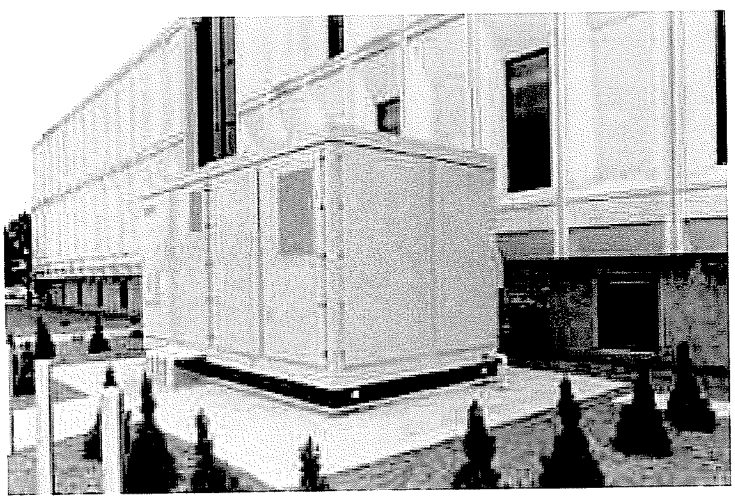


Figure 5-1. 200 kW Fuel Cell (Source: UTC Fuel Cells).

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the capability of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even under part load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized. The potential development of solid oxide fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

Most fuel cell installations are less than 1 MW. Commercial stationary fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other sources of fuel for the reformer under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency and low O&M costs, the environmental benefits of fuel cells remain one of the primary reasons for their development. With natural gas as the fuel source, carbon dioxide and water are the only emissions. High capital costs are the primary disadvantage of fuel cell systems. These costs are expected to drop significantly in the future as development efforts continue, partially spurred by interest by the transportation sector.

5.4.1 Cost and Performance Characteristics

The performance and costs of a typical fuel cell plant are shown in Table 5-7. A significant cost is the need to replace the fuel cell stack every 3 to 5 years due to degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental and power produced by commercial models is not competitive with other resources.

5.4.2 LGE Application

Fuel cells are gaining maturity in the market as a niche technology primarily used for distributed generation. The requirement for fuel is that it must be hydrogen-rich. For the purpose of this study, the fuel cell technology characteristics for LGE are summarized in Table 5-8.

Table 5-8
Fuel Cell – Performance and Costs

Commercial Status	Development / Early Commercial or LGE
Performance	
Net Capacity per Unit, kW	100 - 250
Net Plant Heat Rate, Btu/kWh	7,000 – 9,500
Capacity Factor, percent	30 - 70
Construction Period, months	3 - 6
Economics	
Capital Cost, $/kW	5,000 – 7,000
Fixed O&M, $/kW-yr*	500 - 700
Variable O&M, $/MWh	5 - 10
*Notes: Includes costs for cell stack replacement every four years.	

5.5 Microturbines

The microturbine is essentially a small version of the combustion turbine. It is typically offered in the size range of 30 to 60 kW. These turbines were initially developed in the 1960's by Allison Engine Co. for ground transportation. The first major field trial of this technology was in 1971 with the installation of turbines in six Greyhound buses. By 1978, the busses had traveled more than a million miles and the turbine engine was viewed by Greyhound management as a technical breakthrough. Since this initial application, microturbines have been used in many applications including small scale electric and heat generation in industry, waste recovery, and continued use in electric vehicles.

Microturbines operate on a similar principle to that of larger combustion turbines. Atmospheric air is compressed and heated with the combustion of fuel, then expanded across turbine blades which in turn operate a generator to produce power. The turbine blades operate at very high speed in these units, up to 100,000 rpm, versus the slower speeds observed in large combustion turbines. Another key difference between the large combustion turbines and the microturbines is that the compressor, turbine, generator, and electric conditioning equipment are all contained in a single unit about the size of a refrigerator, versus a unit about the size of a rail car. The thermal efficiency of these smaller units is currently in the range of 20 to 30 percent, depending on manufacturer, ambient conditions, and the need for fuel compression; however, efforts are underway to increase the thermal efficiency of these units to around 40 percent.

Potential applications for microturbines are very broad, given the fuel flexibility, size, and reliability of the technology. The units have been used in electric vehicles, distributed generation, and resource recovery applications. These systems have been used in many remote power applications around the world to bring reliable generation outside of the central grid system. In addition, these units are currently being used in several landfill sites to generate electricity with landfill gas fuel to power the facilities on the site. For example, the Los Angeles Department of Water and Power recently installed an array of 50 microturbine generators at the Lopez Canyon landfill. The project has a net output of 1,300 kW.

Microturbines offer a wide range of fuel flexibility, with fuels suitable for combustion including: natural gas, ethanol, propane, biogas, and other renewable fuels. The minimum requirement for fuel heat content is around 350 Btu/scf., depending upon microturbine manufacturer.

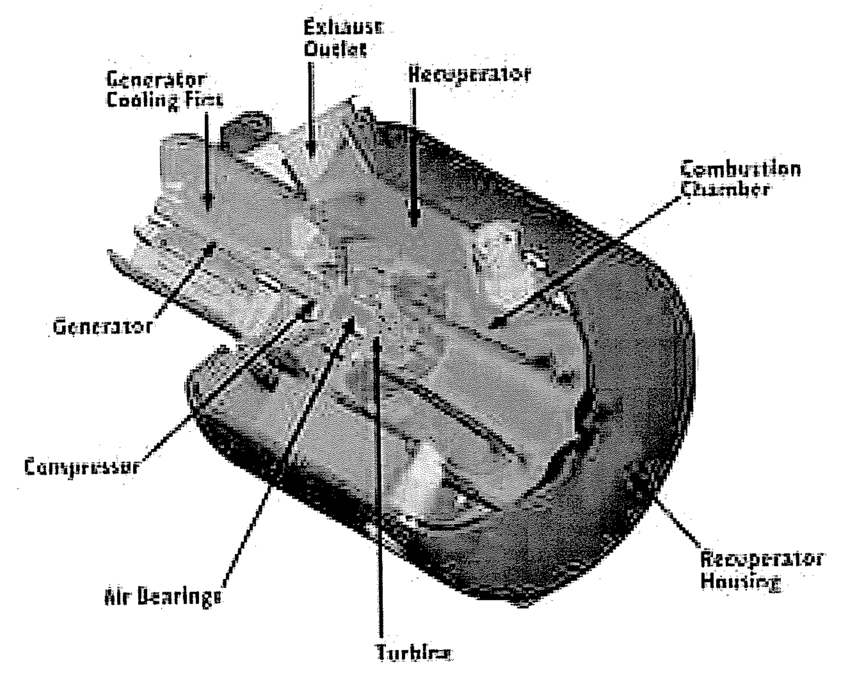


Figure 5-2. Microturbine Cutaway View (Source: Capstone Turbine Corporation.)

5.5.1 Cost and Performance Characteristics

Microturbine costs are often discussed as being about $1,000 per kilowatt. However, this is typically just the bare engine cost. Auxiliary equipment, engineering, and construction costs can be significant. Table 5-9 provides performance and cost characteristics for typical microturbine installations.

5.5.2 LGE Applications

Microturbines are ideally suited for use as distributed generation resources. Because of their small size, they are not suited for use by more than individual consumers. As a possible application, LGE could offer distributed generation capabilities to its customers for peak shaving.

Table 5-9
Microturbines – Performance and Costs

Commercial Status	Commercial	LGE
Construction Period (months)	3 - 6	3 - 6
Performance		
Net Plant Capacity (MW)	0.030	0.030
Net Plant Heat Rate (Btu/kWh)	11,800-13,600	12,000
Capacity Factor (percent)	10-25, 60-80	10
Economics		
Capital Cost ($/kW)	1,000-1,200	1,000-1,200
Fixed O&M ($/kW-yr)	Incl. in VOM	Incl. in VOM
Variable O&M ($/MWh)	10-20	15

6.0 Energy Storage Systems

Energy storage technologies convert and store electricity to help alleviate disparities between electricity supply and demand. Energy storage systems increase the value of power by allowing better utilization of off-peak baseload generation and through mitigation of instantaneous power fluctuations. Different types of technologies are available to provide for a variety of storage durations. Durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (batteries, compressed air, and pumped hydro). These technologies are discussed in this section.

6.1 Pumped Hydro Energy Storage

Pumped hydro energy storage is the oldest and most prevalent of the central station energy storage options. More than 22 GW of pumped storage generation is installed in the US.[10] A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility. Excess energy from the grid (available at low cost) is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required during the high cost, peak electrical demand periods, the potential energy of the water in the upper reservoir is converted to electricity as the stored water flows through a turbine to the lower reservoir.

Capital cost and lead time are the primary considerations in implementing this storage technology. Capital costs are typically very high on a per kW basis and a 4 or 5 year construction period for larger pumped storage facility may be expected. Furthermore, it is becoming much more difficult to gain environmental approvals for damming up the nation's river systems, making the permitting/environmental risk of pumped storage facilities a significant consideration. Geographic and geologic conditions largely preclude many areas from consideration of this technology. Table 6-1 presents typical performance and cost estimates for pumped hydro energy storage.

Black & Veatch has recently studied a pumped storage facility on the Missouri River for the State of South Dakota. Results indicate that the facility would have a cost profile much like a coal unit, in terms of the capital cost per kw and a pumping energy costs linked to coal fired power during off-peak periods. The difficulty is that most pumped storage facilities have a capacity factor in the 15 percent range, making it very difficult for a pumped storage facility to compete with peaking units.

[10] US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Table 6-1
Pumped Hydro Energy Storage – Performance and Costs

Commercial Status	Commercial	LGE
Construction Period (months)	12-38	12-38
Performance		
Plant Capacity (MW)	30 - 1,500+	30 - 1,500+
Capacity Factor (percent)	10 - 15	10 - 15
Economics		
Capital Cost ($/kW)	1,250 - 2,100	1,250 – 2,100
Fixed O&M ($/kW-yr)	5 – 13	5 – 13
Variable O&M ($/MWh)	2.5 - 4.5	2.5 - 4.5

6.1.1 LGE Application

Pumped hydro energy storage has widely varied sizes and costs much like hydroelectric dams. Given the relatively developed and established uses of the river systems in proximity to LGE, it would be a challenge to identify a viable project site.

6.2 Battery Energy Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility system for about 4 to 5 hours. The batteries are then recharged during nonpeak hours. In addition to the high initial cost, a battery system will require replacement every 4 to 10 years, depending on the duty cycle.

Currently, the only commercially available utility size battery systems are lead-acid systems. Research to develop better performing and lower cost batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. More than 70 MW of battery energy storage systems have been installed by utilities in ten states.[11] The largest facility is a 21 MW lead-acid system with 140 MWh of storage capability. The overall efficiency of battery systems averages 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system is provided in Table 6-2.

[11] US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Table 6-2
Lead-Acid Battery Energy Storage – Performance and Costs

Commercial Status	Commercial	LGE
Construction Period (months)	12-18	12-18
Performance		
Plant Capacity (MW)	5	5
Energy Capacity (MWh)	15	15
Capacity Factor (percent)	10 - 25	10 - 25
Economics		
Capital Cost ($/kW)	850 - 1,700	850 - 1,700
Fixed O&M ($/kW-yr)	14.3	14.3
Variable O&M ($/MWh)	53 - 106*	53 - 106*
*Included battery replacement costs.		

6.2.1 LGE Application

If LGE is interested in installing capacity for peak power supply, this could be a potential technology. The sizes and costs are quite variable depending upon the user's needs.

6.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from baseloaded coal and nuclear plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak power demand. A simple compressed air storage plant consists of an air compressor, turbine, motor/generator unit, and a storage vessel, typically underground. Exhaust gas heat recuperation may be added to increase cycle efficiency.

The theoretical basis associated with the thermodynamic cycle for a compressed air storage facility is that of a simple gas turbine system. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate the air compressor. In a compressed air storage generating plant, the air compressor and the turbine are not connected and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or imported oil is reduced by as much as two-thirds compared with conventional gas turbines.[12] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Because fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide more electrical power to the grid than was used during the cavern charging mode.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States with over 75 percent of the land area containing appropriate geological formations.[13] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

The basic components of a CAES plant are proven technologies and CAES units have a reputation for achieving good availability. The first commercial scale CAES plant in the world is a 290 MW plant in Huntorf, Germany. This plant has been operated since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility in McIntosh, Alabama, began operation. This plant remains the only US CAES installation, although several new plants have been recently announced. Table 6-3 shows the performance and cost characteristics of a CAES system.

Table 6-3
Compressed Air Energy Storage – Performance and Costs

Commercial Status	Commercial	LGE
Construction Period (months)	26-29	26-29
Performance		
Plant Capacity (MW)	100 – 500	500
Net Plant Heat Rate (Btu/kWh)	4,000 - 5,000	4,175
Capacity Factor (percent)	10 – 25	25
Economics		
Capital Cost ($/kW)	480 – 7.30	730
Fixed O&M ($/kW-yr)	5.30 – 16.0	11
Variable O&M ($/MWh)	3.20 – 6.35	4.25

[12] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," Journal of Engineering for Gas Turbines and Power, October 1992, Vol. 114.
[13] Mehta, B., "Compressed Air Energy Storage: CAES Geology," EPRI Journal, October/November 1992.

6.3.1 LGE Applications

LGE may be able to install a CAES system if a suitable air storage formation can be found in the local geology. A large system would have cost characteristics similar to the parameters in Table 6-3.

Appendix A. Emissions for Selected Technologies

Estimated Emission Rates for PC and CFB Boilers

	Subcritical PC			Supercritical PC				CFB	
	250 MW	500 MW	500 MW High Sulfur	500 MW	500 MW High Sulfur	750 MW	750 MW High Sulfur	250 MW Low Sulfur	2 x 250 MW Low Sulfur
Boiler Efficiency, %	85.88	85.88	85.88	85.88	85.88	85.88	85.88	84.34	84.34
NO_x									
Uncontrolled, lb/MBtu	0.15	0.15	0.2	0.15	0.2	0.15	0.2	0.15	0.15
Controlled, lb/MBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
CO									
Uncontrolled, lb/MBtu	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
CO_2									
Uncontrolled, lb/MBtu	147.90	147.89	143.61	147.90	143.60	147.90	143.60	143.62	143.61
SO_2									
Uncontrolled, lb/MBtu	1.08	1.08	7.05	1.08	7.05	1.08	7.05	0.15	0.15
Controlled, lb/MBtu	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
PM									
Uncontrolled, lb/MBtu	2.71	2.71	18.90	2.71	18.90	2.71	18.90	0.21	0.21
Controlled, lb/MBtu	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Fuel Analysis

	Low Sulfur PRB	High Sulfur Coal
Ash	5.2%	22.8%
Sulfur	0.45%	4.50%
Carbon	33.70%	50.00%
Heating Value (HHV), Btu/lb	8,350	12,759

Simple Cycle Emissions

			NO_x		SO_2	CO	CO_2	PM_{10}
Plant Configuration	Ambient Conditions	CTG Load Level	ppmvd @ 15% O_2	lb/hr	lb/hr	ppmvd @ 15% O_2	lb/hr	lb/hr
GE LM6000	20 F	Base	25	40.9	0.30	25.0	52,755	4
Simple Cycle		75%	25	33.9	0.20	25.0	41,095	4
		50%	25	27.2	0.20	25.0	30,479	4
	ISO	Base	25	35.7	0.22	25.0	44,500	4
		75%	25	29.3	0.18	25.0	36,540	4
		50%	25	24.2	0.15	25.0	30,290	4
	90 F	Base	25	28.8	0.20	25.0	39,038	4
		75%	25	24.3	0.20	25.0	29,491	4
		50%	25	21.1	0.10	25.0	22,770	4
GE 7EA	20 F	Base	9	36.1	0.60	25.1	121,201	11
Simple Cycle		75%	9	28.9	0.50	29.4	96,593	11
		50%	9	23.3	0.40	32.0	78,186	11
	ISO	Base	9	32.7	0.57	25.3	13,110	11
		75%	9	26.5	0.46	24.6	91,910	11
		50%	9	21.5	0.37	43.4	74,570	11
	90 F	Base	9	29.8	0.50	25.9	102,272	11
		75%	9	24.7	0.40	24.7	82,026	11
		50%	9	20.0	0.10	136.8	66,691	11
GE 7FA	20 F	Base	9	63.2	1.10	7.6	212,582	18
Simple Cycle		75%	9	50.9	0.90	7.4	170,856	18
		50%	9	40.5	0.70	7.6	135,851	18
	ISO	Base	9	59.2	1.03	7.5	204,940	18
		75%	9	48.0	0.83	7.4	166,200	18
		50%	9	38.5	0.67	7.7	133,310	18
	90 F	Base	9	54.2	0.90	7.6	185,752	18
		75%	9	44.8	0.70	7.6	148,333	18
		50%	9	35.7	0.60	8.0	118,458	18

Notes:
1. Emissions data are per stack.
2. Emissions data shown are uncontrolled emissions from the CT exhaust.
3. Fuel gas for the CT is assumed to be natural gas with 100% methane and 0.2 grains of Sulfur/100 scf.
4. ALL DATA ARE FOR INFORMATION ONLY AND CANNOT BE GUARANTEED.

Combined Cycle Emissions

			NO_x		SO_2	CO	CO_2	PM_{10}
Plant Configuration	Ambient Conditions	CTG Load Level	ppmvd @ 15% O_2	lb/hr	lb/hr	ppmvd @ 15% O_2	lb/hr	lb/hr
7EA - 1 x 1	20 F	Base	9	35.6	0.60	25.10	121,201	12
		75%	9	28.5	0.50	29.40	96,593	12
		50%	9	21.0	0.40	32.00	85,516	12
	ISO	Base	9	32.0	0.57	25.30	131,110	12
		75%	9	26.0	0.46	24.60	91,910	12
		50%	9	19.3	0.37	43.40	74,570	12
	90 F	Base	9	29.2	0.50	25.90	105,583	12
		75%	9	23.9	0.40	24.70	82,026	12
		50%	9	17.9	0.40	136.80	74,898	12
7FA - 1 x 1	20 F	Base	9	64.9	1.10	7.60	212,582	20
		75%	9	53.1	0.90	7.40	170,856	20
		50%	9	40.2	0.70	7.60	135,851	20
	ISO	Base	9	58.9	1.03	7.50	204,940	20
		75%	9	48.1	0.83	7.40	166,200	20
		50%	9	36.4	0.67	7.70	133,310	20
	90 F	Base	9	54.2	1.00	7.60	191,072	20
		75%	9	44.3	0.70	7.60	149,333	20
		50%	9	33.5	0.60	8.00	118,458	20
7FA - 2 x 1	20 F	Base	9	130.0	1.10	7.60	212,582	20
		75%	9	108.2	0.90	7.40	170,856	20
		50%	9	80.5	0.70	7.70	135,851	20
	ISO	Base	9	117.8	1.03	7.50	204,940	20
		75%	9	98.0	0.83	7.40	166,200	20
		50%	9	72.9	0.67	7.70	133,310	20
	90 F	Base	9	108.6	1.00	7.60	190,674	20
		75%	9	90.4	0.70	7.60	149,333	20
		50%	9	67.2	0.60	8.00	118,458	20
W501 F - 1 x 1	20 F	Base	25	175.5	1.25	10.00	248,920	20
		75%	25	143.6	1.02	10.00	204,120	20
		50%	25	138.3	0.97	10.00	192,900	20
	ISO	Base	25	159.2	1.14	10.00	227,790	20
		75%	25	130.2	0.94	10.00	186,810	20
		50%	25	125.4	0.89	10.00	177,669	20
	90 F	Base	25	146.6	1.05	10.00	208,730	20
		75%	25	119.9	0.86	10.00	171,140	20
		50%	25	115.5	0.82	10.00	162,800	20

Notes:
1. Emissions data are per stack.
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4. ALL DATA ARE FOR INFORMATION ONLY AND CANNOT BE GUARANTEED.