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Screening Study to Determine the Feasibility of Small Non-Centralized Electric Generating Stations Using Indigenous Fossil Fuel to Supply Energy Needs in Rural Areas in Developing Countries

Prepared by:

Energy and Environmental Engineering, Inc.
35 Medford Street
Somerville MA,02143
P.O. Box 215
E. Cambridge, MA 02141

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Executive Summary

Energy and Environmental Engineering, Inc. has carried out a study of the prospects for local generation of electric power to supply areas not served by the national power grid in developing countries. India, Pakistan, and the Philippines were considered. The technology considered was fluidized bed combustors (FBC's) burning low quality coal locally available.

Examination of the coal resources and the way in which electrical energy production is developing in each of these three countries indicate that good opportunities for coal driven local power generation exist in Pakistan and the Philippines. Such opportunities appear to be less likely in India.

There are clear economic advantages to utilize low cost, low quality coal for which the FBC has a demonstrated capability. Fuel savings for low quality coal at $13/ton versus oil at $18/bbl are about 17 mills/kwh of power generated. Many developing countries have reserves of low grade coal, and utilization of that coal instead of imported fuels offers not only lower costs, but relief from foreign exchange pressures.

Large scale FBC power plants are estimated to cost about the same as conventional coal burning power plants (around $1000/kw), and can burn low quality coal which is very difficult to fire reliably in pulverized coal combustors. However, economies of scale apply to the FBC plants as to all others, and a small FBC plant (e.g. 10 MW) costs about twice as much per unit of capacity as a large (e.g. several hundred MW) plant. The capital cost differential ($2000/kw vs. $1000/kw) translates into an added power cost of about 30 mills/kwh.

From an economic point of view, the obvious course is to build large scale FBC power plants burning low quality coal, since such plants provide the fuel cost savings without accruing any significant capital cost penalty. The advantages of large scale FBC's have been recognized widely; both India and the Philippines have large scale (40 - 50 MW) FBC power plants in operation or under construction.

There has been significant experience with small scale FBC's burning low grade fuels to produce industrial steam in China and in Scandinavia. They work. However, there is little published experience in producing electric power from small scale FBCs. Efficient electric power production requires that steam at much higher pressures and temperature be generated than when the steam is for industrial use. More heat must be transferred to each kilogram of steam made, and the temperature differences available to drive this heat transfer are lower. The net result is that the FBC power plant must have a larger heat transfer area than the industrial steam generator (20 - 30 percent more), and the steam tubes operate at a higher temperature.

While it is perfectly possible to design a small scale FBC to generate electric power from low quality fuels, the differences from established technology cited above pose operational questions. Large scale FBC power plants using high quality fuels are being demonstrated, as are small scale FBCs generating industrial steam. To our knowledge, there are no off-the-shelf small scale FBCs for power generation.

The lack of operating experience with small FBC power plants, together with the diseconomies of capital cost at this scale suggest caution in their application. In addition, skilled labor is required to operate these relatively sophisticated plants, as much to run a small one as to run a much larger one. However, the ability of these plants to burn low quality fuels effectively is of enormous potential advantage to many developing countries. Every effort should be made to develop the technology and to share the accumulating experience of a number of widespread current application among all interested parties.

1 Introduction

Many developing countries face severe shortages of electrical power. Despite additions to electrical generating capacity, demand continues to outpace supply. Energy shortfalls place a serious constraint on economic development. In recent years, power shortages have been over 25 percent of demand in Pakistan and over 10 percent in India.

Electricity demand is growing at a rate of over seven percent in most developing countries and is over 10 percent in Pakistan and India. High growth rates are due to the development of these economies from a rather low level, requiring additional power for industrial needs at the same time that electrical service is being extended to fast growing urban residential sectors and to villages in more remote areas.

The high demand taxes an already overloaded generation and transmission system, resulting in frequent power outages which can cause loss of production to industrial customers. Capital required to provide additional capacity is in short supply, since many utilities in developing countries do not generate enough revenue to meet current capital and operating expenses. Because of their poor financial performance, many utilities do not qualify for loans from international agencies and have had difficulty attracting private capital.

Both India and Pakistan suffer from these problems. Power shortages are increasingly common and are expected to continue for some years. In both countries, autogeneration by industrial users has increased in the face of increasingly unreliable public power. Also, industrial development financing institutions are financing private sector power projects as a necessary part of industrial development.

In order to attract private capital into the power sector, a number of developing countries including India, Pakistan, and the Philippines, have passed laws and put in place national policies that allow and encourage private sector participation. Some private projects are underway.

There are two facets to the problem of increasing electrical power supply. On one hand, additional large scale capacity is needed to supply more reliably the growing demands of the industrialized urban areas already served by the national power grid. On the other hand, the outlying areas not presently on the power grid must be supplied with electricity if these areas are to be able to develop their economic potentials.

In this study, a possible approach for alleviating the latter problem is addressed. Specifically, the proposed approach is to supply outlying areas with power produced locally in small scale (5 - 20 mw) power plants. Fluidized bed combustion technology would

be used to allow these plants to utilize local supplies of low grade coal directly without beneficiation. Such a plant would serve the needs of developing industries and the residents of a village or group of contiguous villages. Financing of the power project could be provided by a private party who has an economic stake in developing the local industry.

This approach has the potential advantages of:

- bringing power to an outlying area in a much shorter time than would be required for extension of the already stressed national power grid;
- bringing private capital to bear under circumstances where the attendant economic development could provide a reasonable return on investment;
- utilizing local low grade coal, not otherwise usable without expensive beneficiation, to provide low cost fuel and reduce foreign exchange requirements.

Specific questions we have addressed are:

1. Under what circumstances does the small scale generation of electricity to serve a limited market make economic sense, as compared to simply extending the power grid to that market?

2. In which countries do significant opportunities for small scale power generations exist, i.e. where are there a significant number of small potential power markets which are relatively near a developed or developable coal supply and relatively far from the existing national power grid?

2 Countries of Opportunity

2-1 India

2-1-1 Coal Resources and Utilization

India has proven coal resources of approximately 46.6 billion tons with an additional 112.6 billion tons indicated or inferred. This coal is mainly bituminous or sub-bituminous coal with relatively high ash content (17 - 55%) and low heating value (4780 - 7170 kcal/kg). The location of these coal reserves is shown on Figure 2-1. Also shown is the location of about 3.3 billion tons of lignite in the southern area Tamel Nadu. This resource could supply the total electrical power of the country at 1986 levels for 18 years.

India has exploited these coal resources significantly, with coal supplying about 65% of the country's energy requirements in 1986. Coal production was reported to be 179.8 million tons per year in 1987/88, with planned expansion to 300 million tons per year by 1995. About 40 percent of the coal production is utilized in generating electricity.

The average cost of coal in India was $13 per ton in 1986, making it a very attractive energy source compared to imported oil.

2-1-2 Generation of Electricity

Table 2-1 shows the 1986 figures for electric power production in India.

Coal accounts for 90% of the thermally generated power and 64% of all electric power produced. These percentages are likely to increase.

For all power production, 8% was privately owned and 92% was publicly owned. For thermal power production, the figures are 12% and 88% respectively. Total power production was increasing at a rate of 7.8% per year, while the thermal component increase was 9.3% per year.

Most of the coal fired power generation utilized stoker or pulverized coal firing of bituminous or sub-bituminous coals. These technologies have encountered problems in firing high ash coals which include difficulty in maintaining combustion and slagging on the steam tubes. Fluid bed combustors, which have been demonstrated elsewhere to be effective in burning low quality coals, have been commercialized in India for industrial steam supply by Bharat Heavy Electricals, Ltd., but little penetration of the utility market is reported.

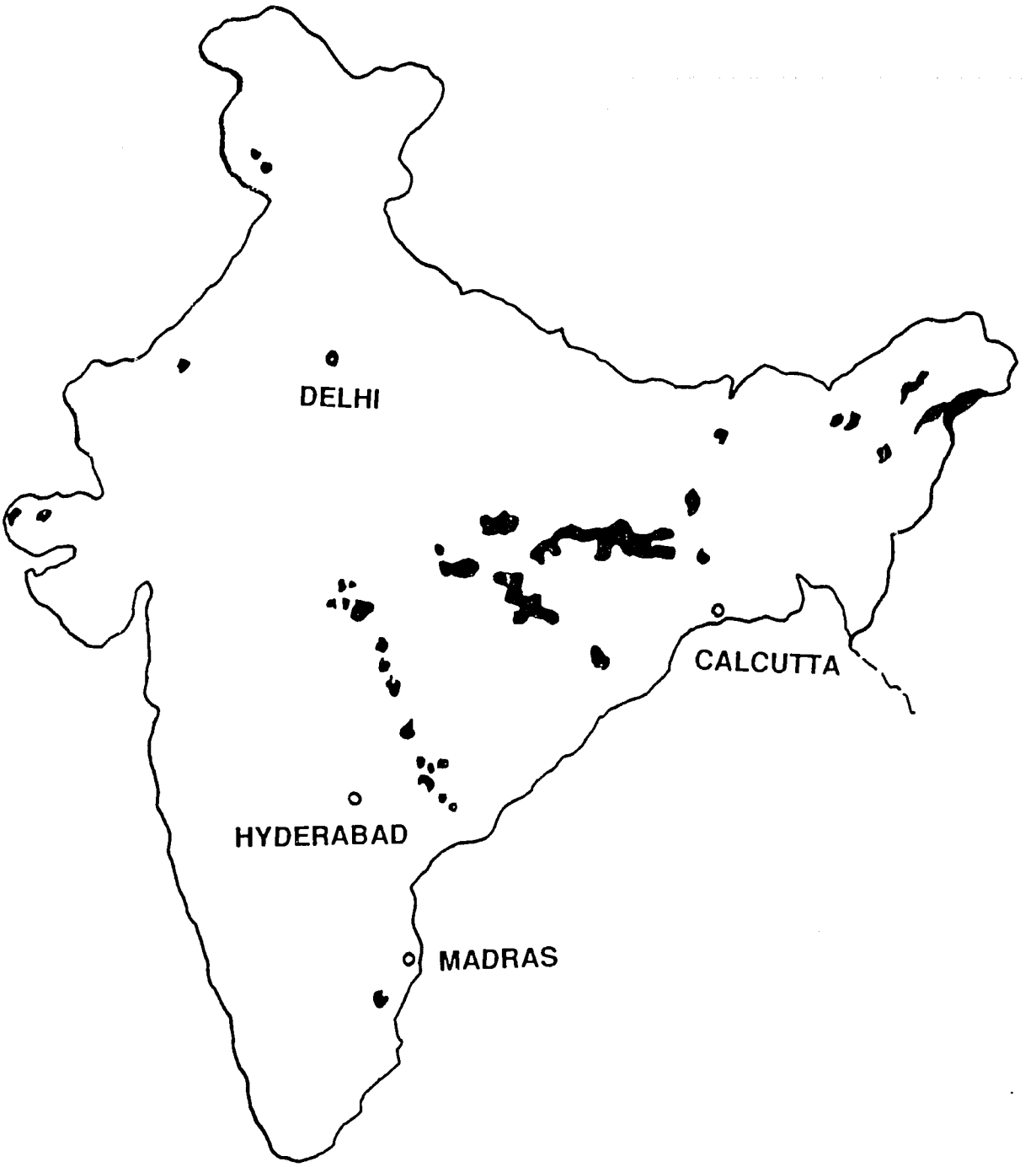

FIGURE 2-1 COAL DEPOSITS IN INDIA

Table 2-1
Electric Power Production - India
(1986)

Type	Installed Capacity(MW)	Power Produced (million kwh/yr)
Hydro	15,965	53,764
Nuclear	1,230	5,022
Thermal	37,494	143,788
Coal		129,840
Oil		9,778
Gas		4,170
Total	54,689	202,574

There is mention of the construction of two FBC lignite power stations, one constructed in 1956 with 600 MW capacity and another in 1978 of 630 MW capacity, later expanded to 1470 MW.

2-1-3 Electrification and Use of Electricity

Approximately 17 percent of the electrical energy generated is lost in transmission and distribution. The remaining 122,600 million kwh in 1986 was utilized as shown below:

Industry	58.3%
Transportation	2.4
Households	12.7
Agriculture	17.1
Other	9.5
	100.0

In most areas of the country, demand exceeds supply. Village electrification is proceeding. In 1977/78, 222,900 villages had been electrified with a target for 1982/83 of 320,000 (about 56% of the villages). Opportunities for local power generation exist. However, since the central power system is largely coal driven, it is likely that villages without power will be closer to the power grid than to a developed coal resource.

2-2 Pakistan

2-2-1 Coal Resources

Pakistan has proven coal reserves of about 85 million tons, including about 16 million tons of sub-bituminous coal in the provinces of Punjab and Baluchistan, and about 69 million tons of lignite in Sind (See Figure 2-2). Indicated and inferred reserves raise the total reserve to 763 billion tons, over half of these reserves being lignite in Sind. The indicated and inferred reserves of lignite would supply the country's power needs at 1986 levels for 18 years.

Pakistani coal is generally of poor quality, as shown in Table 2-2. The sub-bituminous coals in Punjab and Balachistan are high in ash and sulfur, while the Sind lignite is high in moisture and sulfur. Pakistan has been relatively slow to exploit these coal resources. In 1982/83, coal production was 1.9 million tons per year, accounting for about 4.5 percent of the country's energy requirement. Most of the coal produced is used to fire brick kilns. Pakistan has relied on its natural gas reserves, which are overtaxed, and on imported oil to meet its energy needs.

Since the early 1980's, Pakistan has placed emphasis on increased development of the coal resources to produce electricity and reduce the strain on the local gas resource and the need for imported oil.

FIGURE 2-2 COAL DEPOSITS IN PAKISTAN

Table 2-2
Coal Quality - Pakistan

Location	Moisture	Ash	Sulfur	Calorific Value (kcal/kg)
Punjab	3.2-7.6	7.0-37.7	3.5-10.7	3944-6583
Baluchistan	3.1-18.7	1.6-61.6	0.5-8.8	4722-6889
Sind	15.4-29.8	7.4-14.6	3.3-7.4	3894-5444

2-2-2 Generation of Electricity

Table 2-3 shows the 1986 figures for electric power production in Pakistan. Coal accounted for about 0.6 percent of the thermally produced electric power and less than 0.3 percent of the total electric power produced.

Ownership of the hydro and nuclear plants was 100 percent public, with the Water and Power Development Authority and the Karachi Electric Supply Corporation being the lead agencies. These agencies also own about half of the thermal capacity, the other half being privately owned.

Pakistan has embarked on a vigorous expansion of electrical capacity, formally approving induction of the private sector into power generation in 1987. Planned additions to installed capacity by the early 1990's total 9600 MW, including 3500 MW of thermal capacity. The planned additions to thermal capacity include five 50 MW fluidized bed units firing lignite; two of these units will be privately owned.

2-2-3 Electrification and Use of Electricity

About 20 percent of the electric energy produced is lost in transmission and distribution. Of the remaining 21,000 million kwh, industry uses about 31 percent and the rest is consumed by the commercial and residential sectors. By early 1987, 23,400 villages had been electrified, leaving about half of the villages without electricity. Plans call for rural electrification to be 90 percent complete by 1990. However, observers report a need for local power generation in some areas which will not be connected to the power grid for many years. The location of these areas relative to the coal deposits is not known.

2-3 The Philippines

2-3-1 Coal Resources

With several coal producing regions only partially explored, coal resources of the Philippines are estimated at 1600 to 1700 million tons with about 200 million tons of mineable reserves. Mineable reserves could supply the total power production at 1986 levels for 10 years. Most of the coal is sub-bituminous, with significant lignite deposits on the island of Semirara. The character of the coal varies significantly among deposits, with sulfur content ranging from 0.3 to over 4 percent, and ash ranging from 2 to 22 percent. Heating values range from 3700 to 7300 kcal/kg, with most lying in the range of 5000 to 6000 kcal/kg. Figure 2-3 shows the locations of the coal deposits.

The Philippines has made a concerted effort over the last ten years to exploit their coal resources in order to reduce demand for imported oil. Coal production increased from 105,000 tons in 1975 to 1,195,000 tons in 1984, and was projected to increase to

Table 2-3
Electric Power Production - Pakistan
(1986)

Type	Installed Capacity (MW)	Power Produced (million kwh/yr)
Hydro	2548	13,803
Nuclear	137	358
Thermal	2742	11,607
Coal		66
Oil		3543
Gas		7998
Total	5427	25,768

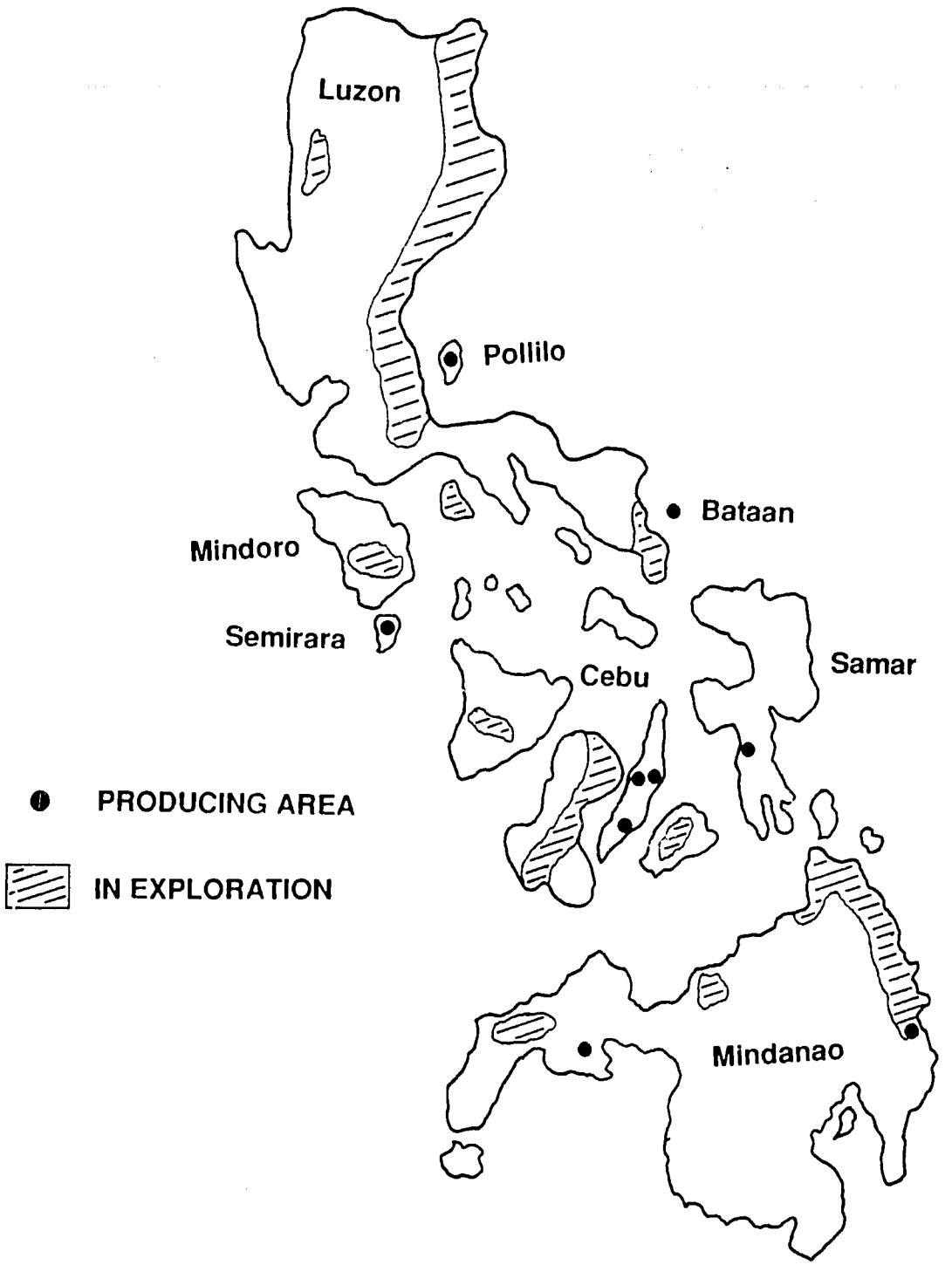

FIGURE 2-3 COAL RESOURCES IN THE PHILIPPINES

3,700,000 tons by 1990. High quality coal has been and will continue to be imported at a rate of about 500,000 tons per year in order to meet the needs of the cement industry and to blend with the poorer local coals for power generation. In 1983, coal production was about evenly divided among mines in Cebu, Semirara, and Zamboanga. Both the public PNOC Coal Corporation and private operators running small mines contribute substantially to coal production.

2-3-2 Generation of Electricity

Power production for 1986 is shown in Table 2-4.

Approximately ten percent of the total installed capacity was privately owned thermal technology. Coal accounted for about 22 percent of the thermally produced electricity and about 11 percent of the total electric power produced. The coal fired plants utilize conventional technology, and operational problems have arisen in burning the lower quality coals. Two 40 MW fluidized bed units are operated privately by the Atlas Mining Company.

2-3-3 Electrification and Use of Electricity

About 23 percent of the electric power produced is lost in transmission and distribution. About a third of the electricity consumed is used industrially, with the remainder going to the commercial and household sectors. There is interest in small (1 - 10 MW) fluidized units to serve isolated markets.

The main islands are well served by central power grids, no point being more than 30 - 40 km from existing transmission lines. Electrical supply problems here are more of generation capacity than of access.

The smaller islands are less well served, and opportunities for local generation likely exist. Transport of coal to these islands by boat from developed resources such as Semirara should minimize coal transport costs.

2-4 Summary of Opportunities

Of the three countries considered, Pakistan and the Philippines seem to offer opportunities for utilization of small scale FBC power plants, while India seems less promising.

India has aggressively developed its large coal reserves and ranks as one of the world's leading coal producers. A high percentage of India's electrical power is coal driven. Since the central power generating system relies so heavily on coal, the generating capacity centers on the developed coal fields and transmits power away from the mines. It is likely, therefore, that most places in India without power are closer to the power grid than to the coal mines. The advantage of local generation in

Table 2-4
Electric Power Production - Philippines
(1986)

Type	Installed Capacity(MW)		Power produced (million kwh/yr)
Hydro	2143		6047
Geothermal	894		4586
Thermal	3425		11,687
Coal		2527	
Oil		9160	
Total	6462		22,320

transport cost of being close to the mine and far from the power grid is not likely to be available.

Both Pakistan and the Philippines are in a much earlier stage in development of their coal resources. Both are expanding coal production rapidly to fuel industry, provide new electrical capacity and replace more expensive fuels in existing electrical capacity. Both countries have been active in rural electrification over the last decade, reducing the need for local generation. With regard to both countries, observers suggest that there are opportunities for local power generation in areas which would not be connected to the power grid for many years.

It was beyond the scope of this study to identify specific opportunities for local power generation, but the general state of power system development and information in the literature suggest that such opportunities exist in Pakistan and the Philippines.

3 Economic Factors

In comparing small scale local power generation with central generation transmitted through the national power grid, several trade-offs must be considered.

- What are the costs of transmitting power by electrical transmission and by the hauling of coal to a power plant located at the market? The cost per kilowatt hour of electrical transmission varies with amount of power transmitted, while the unit cost of coal hauling is independent of scale.

- How does fluid bed combustion technology stack up against the more conventional technologies of pulverized coal combustion and oil firing? Capital cost as a function of scale is important, as is the cost of the fuel consumed. The ease of operations and maintainability of each system must be considered, especially when using low quality, high ash coal.

3-1 Transmission of Energy

Figure 3-1 shows the cost (mills/kwh-km) of transporting power by electrical transmission lines and by hauling coal by truck from the mine to a power plant at the power consuming site. The basic economic assumptions for each mode of transport are summarized in Tables 3-1 and 3-2. The cost of hauling coal includes back hauling the ash from the power plant to the mine for disposal.

Two cost values are shown for transmission. The lower value does not include transmission losses. The higher value assumes losses in transmission of five percent in 100 km. This number is based on reported losses of 10-20% in transmission and distribution with transmission distances of a few hundred kilometers in developing countries. If half of the loss is attributed to distribution (e.g. illegal connections), the transmission loss is of the order of five percent per 100 km.

At lower power levels (below about 50 mw), coal hauling is less expensive than producing power at the mine mouth and transmitting it via power line. This results from the scale dependence of the cost of power line transmission. A 32 kv line will transmit about 5mw of power and costs $61,000 per circuit km. The cost of a 115 kv line, which has a capacity of about 56mw, is $93,000 per circuit km. An increase of over ten times the capacity can be achieved for less than twice the capital cost.

Above about 50 mw, electrical transmission is cheaper than coal hauling, the cost approaching 0.05 mills/kwh-km at power levels of several hundred megawatts. We will take this value as the cost of transmitting power from a central generating site through the extended national power grid to the local market.

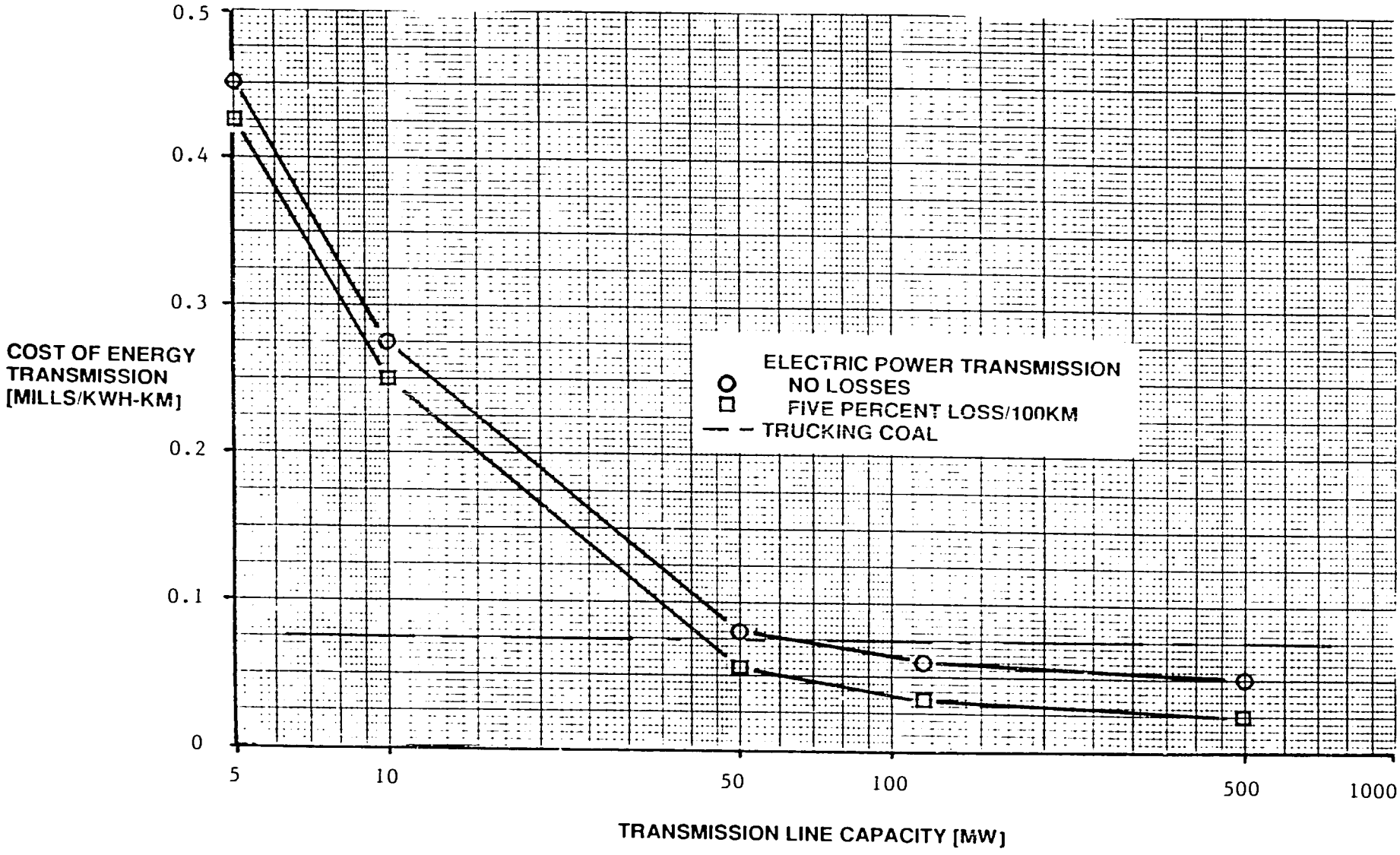

FIGURE 3-1 COST OF TRANSPORTING ENERGY

Table 3-1
Cost of Electrical Power Transmission
Capital Cost

I. Line Voltage (kv)	Circuits	(1) Capacity (MW)	(2) Capital Cost ($/circuit-km)
32	1	5	61,000
32	2	10	76,000
115	1	56	93,000
115	2	112	116,000
345	1	500	373,000

II. Assume:
- Useful life: 20 years
- Interest rate: 15%

gives Annual Capital Charge of 0.16 of principal

- Maintenance: 0.04
  Total annual charge: 0.20
- Load - 70% of line capacity

Transmission Cost

III. Line Voltage (12v)	Circuits	Ann. Charge ($/yr-km)	Eng.Del. (10^6 kwh/yr)	Trans.Cost (mill/kwh)
32	1	12,200	30.7	0.40
32	2	15,200	61.3	0.25
115	1	18,600	343	0.054
115	2	23,200	686	0.034
345	1	74,600	3070	0.024

IV. Electrical Losses during Transmission

Assume: Loss of 5% per 100 km (See text)
Cost of power lost: 50 mills/kwh

Cost of losses per kwh transmitted = (0.0005)(50) = 0.025 mills/kwh-km

(1) Brown, G. Principles of Electrical Utility Engineering, p. 187. Massachusetts Institute of Technology Press (1955)

(2) Personal Communication; Robert Grimshaw, USAID, July, 1989. Costs based on single circuit plus 25% for each additional circuit.

Table 3-2
Cost of Trucking Coal

Assumptions: Capital cost of 20 ton truck: $100,000[1]
Interest rate: 15%
Expected life: 10,000 hrs. or 5 years
Use: 2000hr/yr @ 60km/hr average
or 120,000 km/yr[2]
Heating value of coal: 4000 kcal/kg
Plant heat rate: 3000 kcal/kwh

	$/yr	mills/km
Capital charge	33,000	275
Fuel [50¢/l;1.7km/l]		290
Tires		51[3]
Maintenance		246[3]
Driver @ $1/hr		17
Overhead [incl lic,tax,ins]		105[4]
		984[5]

Cost with backhaul = (984)(2)(1/20)(1/4,000,000)(3,000) = 0.074
(mills/km)(1/ton)(ton/kcal)(kcal/kwh)mills/kwh-km

(1) American Trucking Association, American Trucking Trends, 1987

(2) U.S. average is 130,000km/yr; ibid

(3) Taken at twice reported U.S. averages; ibid

(4) Taken at U.S. average; ibid

(5) The cost per ton-km is 49 mills/ton-km. By comparison, Olanreivan, S.A., Transportation Research, Part A, May, 1987 reports on average cost of 39 mills/ton-km (corrected to 1989 costs in Nigeria).

In estimating the cost of small scale local power production, the power plant will be located at the local market and the cost of hauling coal from the mine to the plant will be taken to be 0.07 mills/kwh-km.

3-2 Fluidized Bed Combustion of Low Grade Fuels

3-2-1 Low Grade Fuels

The sub-bituminous coals and lignite which make up a large fraction of the energy resources of Pakistan, India, and the Philippines are characterized by:

- high moisture and/or ash content,
- relatively low percentage of volatile organics,
- high levels of basic oxides (sodium and potassium) which cause the ash to have a low softening point,
- low heating value

These characteristics lead to several significant problems in the combustion of these fuels in conventional coal combustors. The first problem is that combustion using conventional combustor technology tends to be unstable. The high moisture content and low level of volatile organics makes ignition of the fuel particles difficult. In pulverized coal combustors, the fire is prone to go out, especially at low firing rates.

There are several problems associated with the high ash content and its basic characteristics. Conventional coal combustors normally operate at around 2000°F, which is at the lower limit of temperature at which softening of the basic ash occurs. As a result, conventional combustors have experienced significant problems with slagging and with fouling of heat exchanger surfaces with sticky ash. These occurrences require shutdown of the combustor and cleaning of the surfaces, which are expensive and prevent the combustor from meeting power production design capacity.

Another problem associated with the high ash content of the fuel is erosion of heat transfer surfaces. Ash carried by the high velocity gases passing through the heat exchange bundles wears away the heat transfer surfaces. The problem is exacerbated by the high ash content per kcal of heating value in the fuel, which means that large amounts of ash are thrown against the heat transfer area per unit of power produced.

The design characteristics of fluidized bed combustors provide material relief from most of these problems.

3-2-2 Fluidized Bed Combustors - Design Characteristics

There are two basic types of fluidized bed combustors currently on the market, the circulating bed models and the bubbling bed models. The circulating bed models dominate the present U.S. market, and out-perform the older bubbling beds in most applications. However, it is generally agreed that for small scale installations using low grade fuels, the simpler bubbling bed technology is preferred. Only the bubbling bed technology will be discussed here.

Figure 3-2 show a simple diagram of a bubbling fluidized bed combustor (FBC). Coal and limestone particles are added directly to the fluidized bed which is maintained in a fluidized condition by combustion air, passing out through the bed at a velocity of around 1-3 m/s. The fluidized bed mixes vigorously, maintaining an essentially uniform temperature of around 850C. In the bed, combustion occurs, heat is transferred to in-bed heat exchanger tubes, and sulfur oxides formed in combustion are absorbed by the limestone.

The solids in the bubbling bed provide a relatively long solid residence time in a high-heat capacity environment at 850C, which guarantees successful ignition of the coal particles. In addition, the solids impinging on the in-bed heat transfer area provide heat transfer coefficients between the bed and water in the tubes which are four to five times higher than can be achieved with conventional heat transfer units in which hot gas blows across the surface. The particles impurging on the in-bed heat transfer surfaces do so at sufficiently low velocity that erosion of the in-bed tubes is generally not a problem.

The intense mixing which occurs in the bed together with the high heat capacity of the resident bed materials provides a stable, easily controlled bed temperature, usually designed to be about 850°C. This temperature, significantly lower than commonly used in conventional combustors, is based on a trade-off between high combustion rates and large temperature driving force for heat transfer on one hand, and efficient absorption of sulfur oxides on the other. The reduction in combustion rate associated with the lower temperature is compensated for by increased residence time. The reduction in temperature driving force is compensated for by the high heat transfer coefficients associated with in-bed heat transfers.

The relatively low bed temperature in the fluidized combustor has the added advantage with low grade fuels of being reliably below the ash softening temperature. Problems with slagging of the ash are essentially eliminated.

Ash and spent limestone are continually removed from the bed via a downcomer to maintain the solids inventory in the fluidized bed. The ash removed contains unburnt carbon, and the higher the ash level of the fuel, the larger the carbon loss. Carbon loss

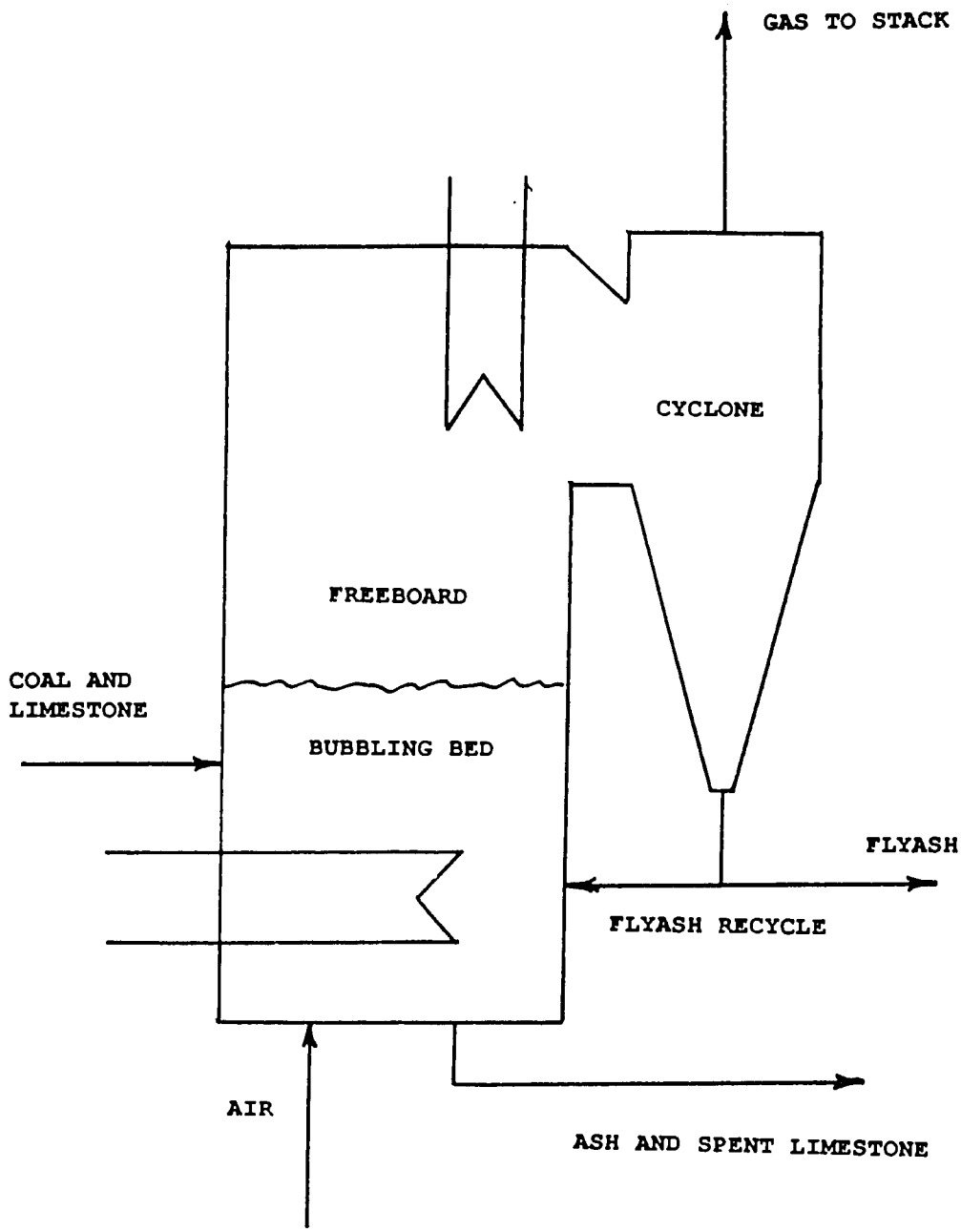

FIGURE 3-2 THE BUBBLING FLUIDIZED BED COMBUSTOR

can be reduced by designing for longer residence times in the bubbling bed.

Hot combustion gases leaving the bubbling bed carry significant amounts of fly ash, in which combustion of residual carbon is still occurring. With low grade fuels, large free board volumes above the bed are helpful in allowing more complete carbon burnout which contributes to high combustion efficiency.

The hot gases pass through another heat exchange system before entering a cyclone separator in which the solids are separated. The separated solids may either be discarded or returned to the bed if carbon burnout in one pass is insufficient. The convective heat exchanger is subject to the same erosion problems as are those in conventional coal combustors. However, because of the lower ash content of the gas and the lower gas velocity in the fluidized bed combustion, the erosion problems are less severe. Experience, described in the next section, has shown that with proper design, tube erosion can be reduced to acceptable levels.

In summary, the design characteristics of the bubbling fluidized bed combustor inherently overcome most of the significant problems that are encountered in burning low grade fuels with conventional coal combustion technology.

3-2-3 Fluidized Bed Combustors - Operating Experience

The periodic boiler census published by Power magazine in 1985 lists over two hundred fluidized bed combustors in operation in the United States. Recent estimates are that over fifty percent of the current industrial boiler market in the U.S. is for fluidized systems. Steam capacities of the installed combustors range from a thousand kilograms per hour to over 600,000 kilograms per hour. Most of these boilers are fired with good quality bituminous coal.

Few of the installed combustors are used for generation of electricity. Almost all are in industrial steam service, supplying steam at pressures from ten to over one hundred atmospheres. Several large fluidized bed power plants are currently being demonstrated in operation, including the Colorado-Ute plant (110mw), the Northern States Black Dog station (125 mw), and the TVA plant at Paducah, KY (160 mw). While experience with these plants is limited, the demonstrations seem to be progressing satisfactorily.

In some countries which have large reserves of low grade fuels, application of small scale FBC's has proceeded rapidly. In Sweden, FBC's are used extensively, burning wood waste, peat, and municipal refuse. The Chinese reported in 1982 that over 2000 FBC's were in operation in China, ranging in capacity from one half to 130 tons of steam per hour. Fuels burned include stone coal, sub-bituminous coal, and coal washery refuse with heating values ranging from 900 to 4000kcal/kg. Erosion problems with the free-

board heat exchangers were solved by welding fins on the tubes. The Chinese emphasize that the FBC must be properly designed to burn low grade fuel in terms of amount of in-bed heat transfer area and sufficient freeboard volume to allow carbon burnout in the fly ash.

In India, Bharat Heavy Electricals, Limited is reported to be marketing FBC's designed to produce 10,000 kg steam/hr from coal wastes with heating value around 2000 kcal/kg and containing 60 to 70 percent ash.

3-2-4 Economics for Electric Power Generation

Since fluidized bed combustors have been little used in power generation, essentially no data as to actual costs exist. However, estimates are available. Leibson published a comparison of the economics of a fluidized bed system and pulverized coal systems, with and without stack gas scrubbing systems to remove sulfur oxides. His results for a 1100 MW power plant are summarized in Table 3-3.

The interesting conclusion of this comparison is that there is no clear advantage in economic terms for either system. The capital coat of the FBC is estimated to be $1130/kw compared to 1130 and 970 for PC combustors with and without scrubbers. Operation and maintenance costs for the FBC are slightly higher, and fuel costs are essentially the same, indicating that the two systems are expected to have very similar fuel efficiency performance.

At the smaller scales of operation of interest here, no published cost estimates were found. However, detailed cost estimates for FBC's in industrial steam service are available. As a preliminary step in estimating the cost of small scale FBC power generation, these estimates were modified to reflect the different conditions and additional equipment needed for electric power generation.

The details of the procedure used in adjusting the steam generation costs to give estimates of electric power generation costs are given in Appendix A. In short, the strategy used was:

- Adjust the steam capacity of the FBC steam generator to give steam at 163 atm. and at 538C with reheat to 538C at the rated fireside capacity of the boiler. This results in significant reduction in steam capacity since the energy required per pound of steam at the conditions listed above is greater than that required to produce industrial steam at lower pressure and temperature and without reheat. The rationale behind this adjustment was to keep fireside additions unchanged.

- Adjust the heat transfer surfaces area required to account for the reduced temperature driving forces

Table 3-3
Comparison of Fluidized and
Pulverized Coal Systems
1100MW Plants
(1986$)

	Fluidized Bed Combustor	Pulverized Coal Combustors with Scrubber	Pulverized Coal Combustors without Scrubber
Capital ($mill)	1300	1330	1140
$/kw, incl. interest during construction	1100	1130	970
Operating Cost (mills/kwh)			
Levelized			
Capital charge	16.9	17.3	14.3
O & M	9.1	8.0	23.8
Fuel costs	24.2	24.3	23.8
	50.2	49.6	44.1

Notes: 1. Coal price @ $2.50/million btu
2. Levelized costs based on 20% equity, 80% debt with 10% aftertax return on equity and 8% on debt. General inflation rate 2.5%.

Reference Leibson, I, Energy Progress, June, 1987, P. 65-71.

available in producing higher temperature steam. Since the major cost of a steam generating boiler is associated with the heat transfer area, the cost of the steam generator for electric power service was taken to be that for the generator in industrial steam service times the ratio of heat transfer areas required for each.

- Add the cost of turbine electric generators with associated electrical gear and condensing equipment. The cost was taken from cost estimates for large scale FBC power plants and assumed to comprise the same percentage of the total direct system capital costs for the smaller scale systems.

The results of these cost estimates are shown in Table 3-4 for FBC power plants ranging in capacity from about 5 to 22 MW. Comparable figures for the 1100 MW plant are also shown. Not surprisingly, it costs more to generate power at a small scale than at a large scale. Unit capital costs for the small plants are about twice that for the large plant reflecting the diseconomies of small scale in equipment costs. There is a general rule of thumb in process design that the capital cost of a facility is proportional to the 0.6 power of the facility capacity. The cost estimates shown in Table 3-4 give a power value of 0.66 among the small plants in the 5 to 22 MW range. From this perspective, the cost estimates appear to be reasonable.

Unit operating costs of the small plants are also larger than those for the large plant, reflecting mainly the labor efficiency achieved in large plants.

Table 3-4
Cost Estimates for Small Scale
Power Generation with FBC's
(1988 $)

	5.7MW[1]	11.3MW[1]	22.5MW[1]	1066MW[2]
Capital cost ($/kw)	2560	2010	1590	1100
Operating Costs (1st year 70% plant factor)				
Capital Charge (at 20%/yr)	92	72	52	36
O & M	24	20	15	9
Fuel ($1.87/ mill btu)	18	18	18	18
	134	110	85	63

Based on Data from:

1. Fluidized Bed Combustion Development, DOE/MC/22024-2339-Vol.1, (1986).
2. Preliminary Assessment of Alternative AFBC Power Plant Systems, EPRI, CS-2275, (1982).

4 Evaluation of Alternatives

4-1 Introduction

Several general conclusions are apparent from the analyses presented above.

- Trucking coal to the power plant at load is cheaper than producing power at the mine mouth and transmitting the electrical power if the power level is less than about 50 MW.

- There are significant economies of scale in power generation. Power from a 10 MW plant costs about twice that from a 1000 MW plant, for the same fuel cost.

- Utilization of poor quality coal is economically attractive for two reasons:

  1. The cost is less - Table 4-1 shows the approximate fuel cost per kilowatt hour for several fuels.

  2. If imported oil or coal is displaced, foreign exchange advantages accrue.

4-2 An Example

Consider an isolated area, and two alternatives for supplying power to that area.

A. An 11 MW local FBC power plant fueled with low grade coal from a mine D_c km away.

B. Central generation at a large (1000 MW) pulverized coal power plant D_t km away fueled with good quality coal and transmission of the electrical power to the area.

Costs for power generation by each of these alternatives are shown in Table 4-2. Figure 4-1 shows the cost disadvantage of the local plant, as a function of the distances Dc and Dt. If Dc and Dt are known, the cost disadvantage ΔC can be read from the figure. For example, if Dc = 100 km, the cost disadvantage of the local plant (ΔC) is about 24 mills/kwh. Figure 4-1 shows clearly that there is a very substantial cost penalty associated with locally generated power unless the power grid is very much further away from the local market than is the coal mine. The added capital cost of small scale generation is difficult to overcome.

Table 4-1
Fuel Costs

Fuel	Cost($/mill. Btu)	Cost(mills/kwh)
Poor quality coal @ $15/ton; 7000 BTU/lb.	1.07	11
Refined or good quality coal @ $50/ton; 10,000 BTU/lb.	2.50	25
Oil at $18/bbl	2.86	29
Oil at $28/bbl	4.44	44

Table 4-2
Comparative Power Costs
(mills/kwh)

	11 MW Local Plant	1000 MW Central Plant
Capital charges	72	36
O & M	20	9
Fuel charges	10	20
	102	65
Transportation of energy:		
Coal	0.07 mills/kwh-km	--
Transmission	--	0.05 mills/kwh-km

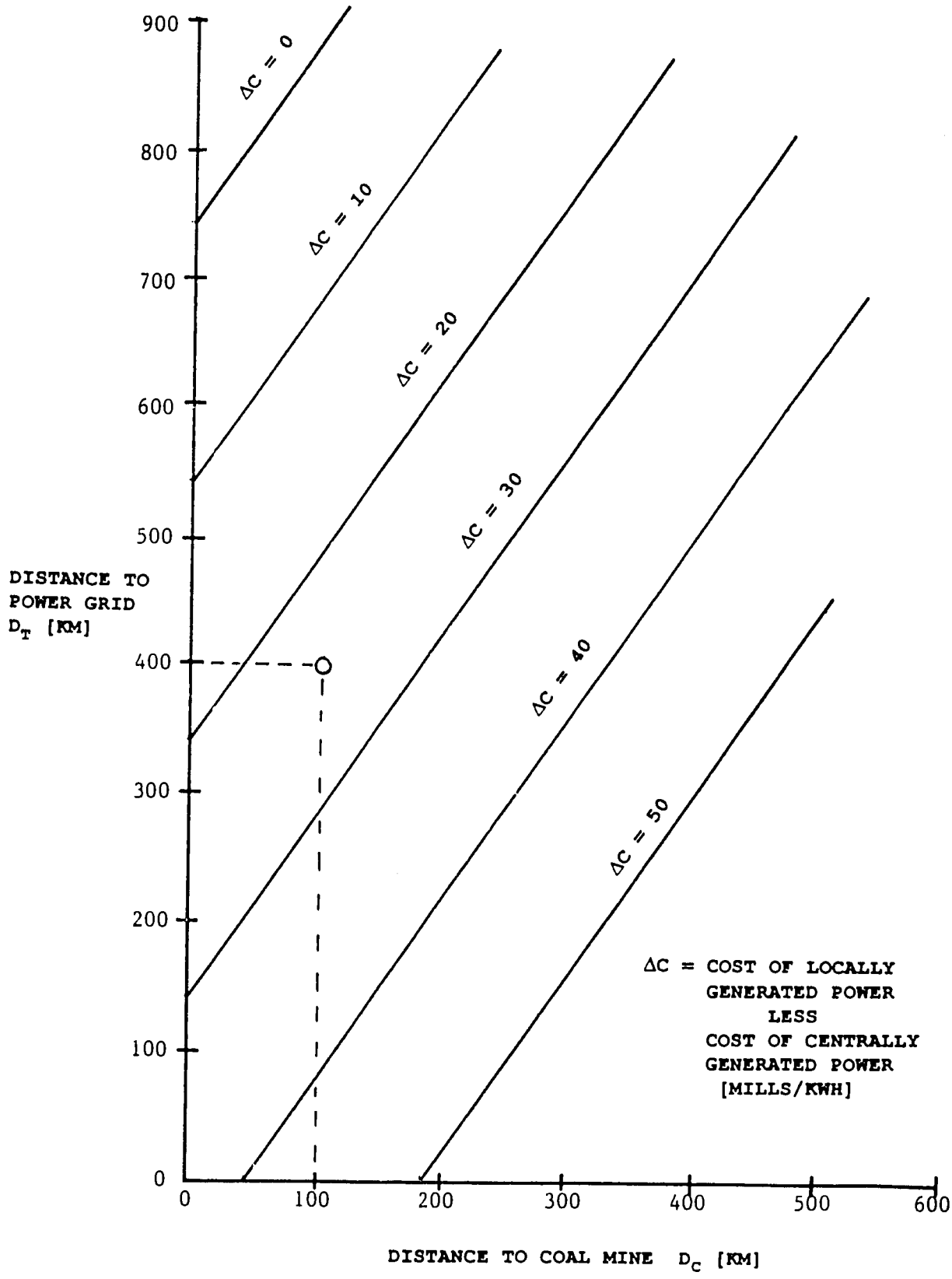

FIGURE 4-1 COST PENALTY FOR LOCAL POWER GENERATION

4-3 Other Factors

In addition to the economics, other factors must be considered. The advantages of local generators are:

1. Power can be supplied to the region sooner. Construction time for small FBC units is 2-3 years, compared to 4-5 years for large field erected central power stations. Additional time, perhaps much, may be required to connect the area to the National Power Grid.

2. Private capital may be attracted to the small scale operation if the owners can realize profits from the use of the electricity. The national climate must encourage private investment.

3. A foreign exchange saving on fuel may accrue if the local coal used in the FBC displaces imported oil or high quality coal.

Disadvantages of local power generation are:

1. Higher cost of electricity unless the grid must be extended a great distance to serve the area.

2. The local plant will not be an efficient element of the national power system, when that system reaches the area, due to its small size and higher costs.

3. The power generation capability of small scale FBC power plants has not been demonstrated extensively, although small scale industrial steam generation has. Skilled labor is required for operation.

4. Control of a local, single-plant system is difficult. When the plant goes down, there is no back-up capability.

Weighing the advantages and disadvantages of small scale, local power generation, it seems unlikely that small scale power generation using FBC technology is generally a good idea. There may, however, be special situations where it is attractive. If the power produced will have a significant leverage effect on the local economy, and when the time to connections to the power grid is long, small scale power generation could be an attractive opportunity.

4-4 Another Alternative

An alternative to small local plants serving a local market is the larger (say 50 MW) plant serving a regional market. Such a plant could consist of two or three small boilers so that maintenance of continuous power could be assured. Such a plant would achieve some economics of scale, and maintain most of the

advantages of the local plant, while mitigating most of the disadvantages.

Some economies of scale could be realized, making the plant a more attractive candidate for inclusion in the national power system and mitigating the skilled labor requirement. Foreign exchange disadvantages associated with use of local fuel would be realized.

One advantage of the local plant would be lost. The capital investment required for a regional plant and the scope of the market may make the venture less attractive to private capital.

In any case, this alternative should be considered as an attractive way of filling gap in the national power grid in a timely and efficient manner.

Appendix A
Estimation of Costs of Small Scale FBC Power Plants

The estimates for small FBC power plants are based on detailed cost estimates for large scale power plants and small scale industrial steam plants. The basic references are:

- Preliminary Assessment of Alternative Atmosphere Fluidized-Bed Combustion Power Plant Systems, EPRI, C5-2275, February, 1982 - Large scale power plants.
- Fluidized-Bed Combustion Development, Final Report, Volume 1, USDOE, DOE/MC/22024-2339-Vol. 1, May, 1986- Small scale steam generators.

1. Power plant based on 200,000 lb/hr boiler

The power boiler generator steam at 2400psig at 1000F with reheat to 1000F. Heat added per pound of steam is:

Boiler Sensible heat from 106F to 662F, ΔH = 644 Btu/lb.,
Latent heat at 662F ΔH = 383 Btu/lb
Sensible heat from 662F to 1000F ΔH = 359 Btu/lb

Reheat Sensible heat from 570F to 1000F ΔH = 243 Btu/lb
Total heat = 1629 Btu/lb

The boiler combustion zone operates at 1550F, and it is assumed that all heat is transferred from the fireside at 1550F. Therefore, the average temperature difference for transferring each portion of heat can be calculated.

Boiler 644 Btu/lb $\Delta T = \dfrac{(1550-106)-(1550-662)}{\ln \frac{1550-106}{1550-662}} = 1143F$

662 Btu/lb $\Delta T = 1550-662 = 888F$

359 Btu/lb $\Delta T = \dfrac{1000-662}{\ln \frac{888}{550}} = 706F$

Reheat 243 Btu/lb $\Delta T = \dfrac{1000-570}{\ln \frac{980}{550}} = 744F$

The total heat transfer area required can be estimated from the general equation

$$A = \frac{1c\ q}{h \Delta T}$$

where h is the heat transfer coefficient. For simplicity, it is assumed that the h's are the same for each portion of the heat transfer. Then,

$$A^1 = \frac{1}{h} \sum_i \frac{Q1}{\Delta Ti}$$

$$= \frac{1}{h}\left[\frac{644}{1143} + \frac{383}{888} + \frac{359}{706} + \frac{243}{744}\right] = 1.830/h$$

Consider now a steam generator producing saturated steam at 350 psig (T = 435.7F) starting from boiler feed water at 240F. This is the design condition of the industrial boilers costed by USDOE. Making the same calculation as above:

Boiler: Sensible heat from 240F to 435.7F; ΔH = 205.8 Btu/lb; ΔT = 1210F (based on 1550F bed temperature)
Latent heat at 435.7F ΔH = 790.0 Btu/lb; ΔT = 1114.3F
Total heat = 205.8 + 790.0 = 995.8 Btu/lb

$$A^1 = \frac{1}{h}\left[\frac{205.8}{1210} + \frac{790}{1114.3}\right] = 0.8790/h$$

Therefore, to maintain fireside conditions the same, the steam rate in the 200,000 lb/hr boiler must be reduced to

$$S = So(Qo/Q) = (200,000)(995.8/1629) = 122,000 \text{ lb/hr}$$

if the stream produced is power generation quality (i.e. 2400 psig/1000F/1000F).

The heat transfer area must be increased to account for the increased heat load:

$$A = Ao(S/So)(A^1/A^1o) = Ao\frac{(122,000)}{(150,000)}\frac{(1.830)}{(0.879)} = 1.273\ Ao$$

The base large scale power plant described by EPRI produces 1066MW at a steamflow of 5.76 million pounds steam/hr. Therefore the electrical capacity of the small scale plant being considered is

$$(1066)\frac{(122,000)}{(5,760,000)} = 22.5 \text{ MW}$$

The capital cost of the small power plant was estimated from the costs presented by DOE for the comparable industrial steam plant. Two adjustments were made. First, the cost of the boiler was increased by the rates of heat transfer areas required (in this case, 1.273). Second, the costs of turbo-generation with related peripheral equipment and switching gear and a steam condensing

system was added. This cost was assumed to be the same percentage of total directed cost as in the large scale power plant described by EPRI.

The EPRI cost estimate is $522 million in direct cost for the large scale power plant; of this amount, $160 million is associated with the turbo-generators, related equipment, and condensing system. Therefore, the fractional cost is

$$(160)/(522-160) = 0.442$$

The capital cost estimate for the small scale power plant was developed as shown in Table A-1. The first column lists costs (in 1986 $) as reported by DOE for the industrial steam plant. In the second column, the cost of a steam generator is adjusted upward as described above, and the cost of the turbo-generating system is added. Costs are adjusted to 1988 $ in the third column, using the M & S index.

Operating costs are also shown on Table A-1. Capital charges are set at 20 percent per year with a 70 percent capacity factor. O and M costs are taken from USDOE and fuel charges are based on USDOE data.

Tables A-2 and A-3 show comparable estimates based on steam generators of 100,000 and 50,000 lb/hr, respectively.

Table A-1
Cost Estimate for 22.5 MW
FBC Power Plant

Capital Cost	1986$ (1) (for 200,000 lb/hr steam generator)	1986$ (2) (for 22.5 MW Power Plant)	1988$ (2) (for 22.5 MW Power Plant)
Steam Generator	8,700,000	11,100,000[3]	12,200,000
Auxiliary	4,200,000	4,200,000	4,600,000
Turbine Generator	-	6,800,000[4]	7,500,000
	12,900,000	22,100,000	24.300,000
Indirect Lots	6,100,000[5]	10,500,000[5]	11,500,000[5]
Total	19,000,000	32,600,000	35,800,000
			$1590/kw

Operating Costs		
Capital Charge @ 20%/yr	47.3	52
O & M	13.9[1]	15
Fuel ($1.87/mill. Btu)	-	18
		85

(1) Reference USDOE
(2) Estimate E3I
(3) (8,700,000)(1.273)
(4) (15,200,000)(0.442)
(5) 0.473 of Direct Costs

Table A-2
Cost Estimate for 11.3 MW
FBC Power Plant

Capital Cost	1986 $ (1) (For 100,000 lb/hr steam generator)	1986 $ (2) (For 11.3 MW Power Plant)	1988 $ (2) (For 11.3MW Power Plant)
Steam Generator	5,400,000	6,900,000	7,600,000
Auxiliaries	2,800,000	2,800,000	3,100,000
Turbine Generator	-	4,300,000	4,700,000
	8,700,000	14,000,000	15,400,000
Indirect Lots	3,900,000	6,600,000	7,300,000
	12,100,000	20,600,000	22,700,000
			$2010/kw

Operating Costs		
Capital Charge @ 20%/yr	66	72
O & M	18(1)	20
Fuel ($1.87/mill Btu)	-	18
		110

(1) Reference USDOE
(2) E3I Estimates

Table A-3
Cost Estimate for 5.7 MW
FBC Power Plant

Capital Cost	1986 $ (1) (For 50,000 lb/hr steam generator)	1986 $ (2) (For 5.7MW Power Plant)	1988 $ (2) (For 5.7MW Power Plant)
Steam Generator	3,500,000	4,500,000	5,000,000
Auxiliaries	1,600,000	1,600,000	1,800,000
Turbine Generator	-	2,700,000	3,000,000
	5,100,000	8,800,000	9,800,000
Indirect Costs	2,500,000	4,300,000	4,800,000
	7,600,000	13,100,000	14,600,000
			$2560/kw

Operating Costs (mills/kwh)

Capital charge @ 20%/	84	92
O & M	22	24
Fuel	--	18
		134

(1) Reference USDOE
(2) E3I Estimates

Appendix B

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