Energy Policy, Vol. 26, No. 7, pp. 557–575, 1998

Printed in Great Britain
0301-4215/98 $ 19.00 + 0.00

ELSEVIER

PII: S0301-4215(98)00003-2

Price of power in India

Rahul Tongia and Rangan Banerjee*
Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213, USA

The Government of India liberalized its economy in 1991, opening up the power sector to private participation. The existing Central Electricity Authority guidelines for Independent Power Producers (IPPs) are analyzed to obtain the net price of power and the internal rate of return for coal and combined-cycle natural gas power plants, under different assumptions of input parameters. The results show rates of return higher than the nominal 16%. An uncertainty analysis reveals the relative importance of various parameters. Problems with the existing guidelines are shown, providing insights for policy changes. Adoption of modified guidelines for IPPs which are more transparent are likely to result in more affordable tariffs, less delays and yet provide adequate rates of return for investors.

Keywords: Electricity price; Independent power producers (IPPs); Central Electricity Authority; India

Introduction

The 1991 changes in the Indian power sector opened the way for private participation in the power sector. Faced with acute shortages of power,[1] the government offered incentives for Independent Power Producers (IPPs) to enter the generation sector. It was thought that this move would dramatically increase power production, but this has not been the case. During the VIII Plan period (1992–97), the projected requirement for addition of capacity (excluding captive power) was 48,000 MW. The resource-based plan target was 30,538 MW, but the actual anticipated capacity addition is likely to be in the neighborhood of 17,000 MW.

There are many reasons why the government feels that IPPs are not only necessary but beneficial to the Indian power sector. Some general pros and cons of IPPs in developing countries are given by Dunkerley (1995). In the Indian context, the primary reason appears to be resource limitations of existing utilities and public sector units. Other important reasons include the aim of rapid increase in generation capacity, as well as high expected operating efficiencies and availabilities.[2]

While interest in the Indian power sector remains high among generation companies, there are questions as to the causes of the slow progress. Indeed, of the eight so-called 'fast-track' projects, in 5 yr, only one has begun generating power. Many of the fast-track projects have been bogged down in controversies. A striking example is the Enron project which was almost canceled but later revived after re-negotiation. Parikh (1996) provides an overview of the happenings in the Enron case. A summary of the arguments against the Enron deal is given by Sant *et al* (1995).

In many cases the State Electricity Boards (SEBs, the Indian utilities) enter into bilateral negotiations with companies (such as the fast-track projects[3]). Even where the utilities opt for competitive bidding, there is a possibility that the large suppliers can collude to set higher prices. In addition, there is considerable public perception that these deals are unfair, leading to public-interest litigation and delays. On the other hand, if these deals are fair (at the least, not being manipulated), the effect of these delays is increased cost of power, both directly because of delays, and indirectly because of increased risks (both perceived and actual). Hence, it is important to identify the factors affecting the cost of power and the returns on IPP investment. The cost of power is an important consideration, especially for a developing

* On leave from Indian Institute of Technology, Bombay.

[1] Officially, the 1996–97 shortage is stated at 11.5% average and 18% peak (Ministry of Power, 1997). Unofficial estimates place the numbers at almost 15% and 30%, respectively.

[2] This is not to say all Indian public sector units suffer from poor performance. The National Thermal Power Corporation, which supplies the bulk of recently added coal-fired power, has improved its one year plant load factor to 78.8%, and its newer plants have availabilities over 80% (NTPC, 1996).

[3] Fast track projects were also unique because of counter-guarantees by the central government for payment of purchased power. The central government has stopped issuing such counter-guarantees, a move which might be perceived as increasing the riskiness of investing in power projects in India.

country such as India. If the price is too high, not only will it lead to a competitive disadvantage for industry, but also it will lead to an inability to pay. Already, Indian commercial and industrial users cross-subsidize agricultural and domestic users.

In this study, we examine the expected levelized price of power from new Indian power plants[4] using both the government guidelines as well as an alternative methodology. The two types of plants we have chosen are 500 MW sub-critical pulverized coal and 250 MW combined-cycle gas turbine plants. The primary objectives of this study are to examine the price of electricity and the returns enjoyed by IPPs.

Central Electricity Authority guidelines

The government agency responsible for techno-economic clearances for power projects as well as tariff-setting (for large projects) is the Central Electricity Authority (CEA). The CEA has issued tariff-setting guidelines which are used by the SEBs to set tariff ceilings for power purchase agreements. However, in the absence of competitive bids for power, it is unlikely that projects will offer prices significantly lower than those stipulated in the guidelines.

The CEA guidelines outline a two-part tariff, separating fixed and variable costs. The fixed costs are recoverable at a normative level of generation, while the variable costs are based on actual generation. A summary of the CEA guidelines is presented below (Central Electricity Authority, 1997; Ministry of Power, 1994).

The guidelines provide for what is essentially a cost-plus tariff. Capital costs are determined by the total expenditure on the plant.[5] The tariff is set assuming pro-rata expenditure of debt and equity during construction, with capitalization of (debt) Interest During Construction (IDC). Debt : equity ratio is important for other reasons, as the tariff allows for a fixed return on equity. The maximum permissible debt : equity ratio is 4 : 1; there is no minimum debt component.

Fixed costs

Fixed Costs are recoverable at a normative level of generation, currently set at 6000 kWh/kW/yr, or 68.5% Plant Load Factor (PLF). The components of Fixed Costs include–

(1) *Interest charges*: The tariff reflects charges equal to the interest on the loan for the duration of the loan package. This is based on the approved loan package. As the loan is likely to be for a shorter duration than the life of the plant, the tariff is higher during the early years of operation.
(2) *Operating and maintenance (O&M) costs*: The CEA guidelines treat all O&M costs as fixed costs, instead of the more standard practice of separating fixed O&M costs from variable O&M costs. O&M costs are initially based on the total plant costs, and can be revised after time as per the operation record (typically after 5 yr).
(3) *Taxes*: Taxes are treated as a fixed cost, and are passed through to the tariff. This is done to allow a nominal return on equity *after taxes*. There is a five year tax holiday from the date of commercial operation. We do not include taxes as part of our model.
(4) *Depreciation*: Depreciation is treated as a fixed cost, and must be as per gazetted norms. While the actual norms are complex, for a power plant the overall annual rate comes to approximately 7.5%. This level of straight-line depreciation can be continued for 12 yr, leading to the maximum allowed depreciation of 90%.
(5) *Return on equity (RoE)*: Nominal RoE is 16%. It is important to realize that this is post-tax, in the currency of investment (say, US$). There are also guarantees to cover the risks of foreign exchange escalation.

Clearly, this is a top-heavy tariff, decreasing once the loan has been paid off and the depreciation taken. Choice of levelizing[6] rate becomes an important issue for comparing different projects.

Variable costs

These are based on the actual generation.

(1) *Fuel consumption*: This is based on an assumed heat rate, 2000 kcal/kWh for combined-cycle gas plants and 2500 kcal/kWh for coal-based plants.
(2) *Auxiliary fuel consumption*: This is for coal-based stations, equal to 3.5 ml/kWh (liquid fuel).
(3) *Auxiliary power consumption*: 3% for combined-cycle gas plants, and 9.5% for coal plants with a cooling tower (8% if the coal plants have steam-driven pumps). It is important to realize that the Indian power sector largely deals with gross generation levels. When a price for Rupees/kW is quoted in India, it is gross capacity price, not busbar.

If the generation is below the normative PLF, there will not be full recovery of Fixed Costs. For generation above normative PLF, there is no charge towards Fixed Costs, except for a 0.7% additional return on equity for

[4] A significant number of upcoming plants are expected to be IPPs. In addition, many public sector units also follow the same CEA guidelines for tariff setting.

[5] The guidelines state that if the plant costs are higher than projected for no fault of the IPP or contractor, the tariff will be based on the actual higher costs, subject to approval.

[6] Levelizing is the process of converting a tariff which varies over time into an equivalent constant tariff. Levelizing rate is the discount rate used to convert the varying tariff into an equivalent constant tariff with the same net present value.

Table 1 Capital Costs— Specifications

	Units	Gas	Coal
* Generation capacity (net)	MW	250	500
* Construction time ($= t_{constr}$)	Months	24	48
* Overnight construction costs (OCC)	\$/kW	430[a]	860[b]
Contingency (@10% of OCC)	\$/kW	43	86
* Land area	ha/kW	7.5×10^{-6} [b]	2.1×10^{-4} [b,c]
Land cost[d]	\$/m^2	3	3
Land	\$/kW	0.225	6.18
Transit costs (@5% of OCC)	\$/kW	21.5	43
* Switchyard	\$/kW	18[b]	18[b]
Direct capital costs (DCC) (OCC + land + switchyard + transit)	\$/kW	512.7	1013.2
* Fraction of OCC imported[e]		70%[b]	50%[b]
Value of fraction imported	\$/kW	301	430
Import duties (@20% of OCC)	\$/kW	60.2	86
Construction funds outflow (transposed logit model) $p' = \frac{1}{(1 + e^{-(k_2 + k_1 t/t_{constr})})}$; $p = 0.9p' + 0.1$[f]			
p = cumulative expenditure of DCC per period			
constant k_1		9	9
constant k_2		– 4.3	– 4.3
* Debt: equity		4:1	4:1
* Annual escalation rate			
Imported	per yr	4%[g]	4%[g]
Non-imported (labor/domestic)	per yr	8%[h]	8%[h]
Escalation during construction (ESC)		4.7%	11.0%
* Interest during construction (IDC) rate[i]	per yr	12%	12%
IDC (calculated at 4:1 debt: equity)		11.0%	24.9%
ESC + IDC		15.7%	35.9%
Total capital costs (total plant investment) DCC x (1 + ESC + IDC) + Import	\$/kW	653	1463[j]

Note: This table goes through the base case calculations for capital costs. Not included in the model is capitalization of working capital, initial spares, etc., which is allowed under the CEA guidelines.
* Indicates inputs to the model.
[a] *Assumptions for the Annual Energy Outlook 1997* (EIA, 1996).
[b] *IPPI Power Plant Cost Study- Compilation of "Hard" and "Soft" Costs for Power Plant Development in India* (RCG/Hagler Bailly, Inc. *et al*, 1994). Coal plants include electrostatic precipitators with a collection efficiency of 99.8% and do not have flue gas desulfurization.
[c] Includes ash disposal.
[d] Subjective; very site-specific.
[e] Approximation based on major factory equipment.
[f] The actual cash flow corrects the last month to reach complete expenditure, i.e., $p(t = t_{constr}) = 1$.
[g] Slightly higher than US Producer Price Index Inflation for the period 1990–95. *Statistical Abstract of the United States 1996 (116th edition)* (US Bureau of the Census, 1996). The actual real price of combined-cycle gas plants has been falling over time, and is in the neighborhood of \$425/kW. Even greater than price reductions are the improvements in efficiency, rising over 50% and projected to cross 60% (net, higher heating value) within the next decade (Tony Roeder, ABB, *Technologies for the Future Power Market*, presented at Shell International Petroleum Company Ltd. Workshop 'The Emerging Power Industry', December 1995).
[h] Approximately equal to Indian inflation from 1992 through 1996. The Wholesale Price Index shows considerable variation between sectors, so 8% appears to be reasonable for general commodities and goods. *Economic Survey 1996–97* (Ministry of Finance, Govt. of India, 1996).
[i] Same as loan rate.
[j] This price for coal plants is more in line with prices seen in the US. Unofficial reports place the costs of coal plants in India as a good deal lower, perhaps in part due to different environmental control requirements. The effect of varying capital costs for coal plants is included in sensitivity analysis.

each percentage PLF increase over normative. The CEA guidelines also allow for other practical incentives for IPPs, including capitalization of interest on working capital, initial spares, initial fuel, etc., which are not treated explicitly in the model. Pass through of taxes into tariff is only up to the normative level of generation.

Costing model

In this paper, we examine how the CEA guidelines affect IPP returns and the price of power. With a tariff-setting methodology that allows for a nominal return on equity, it is important to know the exact capital costs of a power plant. There have already been criticisms of the CEA guidelines, for example, the incentive to gold-plate facilities (Parikh, 1996). We have constructed a model for examining the two parameters of interest, the price of electricity (\$/kWh or Rs./kWh), and the returns for the investor, in net present value (NPV). Tables 1 and 2 show input values as well as calculated capital costs from the model. Figures 1 and 2 show simplified diagrams of our model.

The levelized cost of power will largely depend on: capital (construction) costs, operation and maintenance (O&M) costs, and fuel costs. Typically, fuel costs are not controlled by the builder/operator but rather are

Table 2 Base case model parameters

	Units	Gas	Coal
Fixed O&M costs[a, b]	\$/kW/yr	26.5	38.6
Variable O&M costs[a]	¢/kWh	0.04	0.3
Fuel price	\$/MMBtu[c]	4[d]	1.8[e]
	(\$/10^6 cal)	(0.0159)	(0.0071)
Avg. net heat rate[f]	Btu/kWh[g]	7520	9736
	(kcal/kWh)	(1895)	(2453)
Debt interest rate	per yr	12%	12%
Loan duration	yr	12	12
Annual depreciation[h]	per yr	7.5%	7.5%
Return on equity[i]	per yr	16%	16%
Exchange rate	Rs./US\$	35.5	35.5

Note: [a] EPRI-TAG 93.
[b] While different sources make distinctions between fixed and variable O&M differently, it is consistent that O&M costs for coal are higher than for gas, both fixed and variable [EPRI-TAG 93, Assumptions for the Annual Energy Outlook 1997 (EIA, 1996), IPPI Power Plant Cost Study- Compilation of "Hard" and "Soft" Costs for Power Plant Development in India (RCG/Hagler Bailly, Inc. *et al*, 1994)]. We have chosen the set of numbers that has a high fixed cost and proportionately low variable cost (which best approximates the CEA guidelines, which only allow for secondary fuel consumption for variable non-fuel costs).
[c] These fuel prices are in nominal dollars, for the year when the plant begins operation, i.e., 1999 and 2001, respectively. A discussion of comparing costs and prices across years and the associated difficulties is given in the text.
[d] This is a higher-end gas price, likely to be the case for imported LNG.
[e] This price is based on grade D coal (4570 kcal/kg average useful heating value). This corresponds to approximately Rs. 1159/tonne. The price for coal at the pithead is likely to be in the neighborhood of \$1.3/MMBtu, or Rs. 817/tonne (2001 nominal prices, based on zero real escalation). An additional charge of \$0.50/MMBtu is taken as coal transport charges, for approximately 400 km.
[f] Higher Heating Value.
[g] The actual heat rates will vary based on load; this is an expected average over the year (*EPRI-TAG 93*). There are likely to be improvements in heat rates over the coming years, especially for the case of combined-cycle gas turbine plants.
[h] Depreciation continues for 12 yr, leading to the maximum allowed depreciation of 90%.
[i] 16% nominal RoE is based on normative level of generation, i.e., 6000 kWh/kW/yr.

determined by the market or supplier, and are passed through into the electricity tariff. The O&M costs are generally of two types, fixed – insurance, labor, etc., and variable – spares, maintenance, etc. While the CEA guidelines do not split O&M costs into these distinctions, we have done so for model clarity.

The outlay of capital during the construction period varies as an S-shaped curve, which we approximated as a logit curve over the months of construction. A conservative model of expenditure was chosen, with approximately 10% of the direct construction costs expended at the onset of construction ($t = 0$), and 60% expended by the mid-way point. The base case construction periods are taken as 24 and 48 months for gas and coal, respectively. As the construction time was varied parametrically for this study, it was assumed that the general characteristics of the curves (percentage of construction completed at a corresponding percent of total construction time) would remain the same. Any construction occurring after $t = 0$ is escalated according to the rates shown in Table 1. Any debt expenditure on construction accrues interest during construction. Based on these, there is a extra factor for escalation during construction (ESC) and interest during construction (IDC) applied to the direct construction costs (DCC). Figure 3 shows the outlay of capital (including escalation and interest during construction). In addition to the plant costs, there are additional charges for the electrical switchyard and land. Contingency is already included in the capital costs. The exact numbers for a project will vary based on site and market conditions. These numbers are meant to be representative, and will be useful for examining trends based on variable and uncertain parameters.

Equity and returns

Figure 2 shows the influence diagram for determining the NPV of equity investments. To summarize the diagram, the approved capital package leads to a particular tariff (which can vary over time). After subtracting from this tariff the debt servicing obligations, the equity cash flow is obtained. The three components of capital recovery charges are nominal return on equity, interest charges, and depreciation. Taxes are a pass through, as are O&M costs. This is not to say there might not be margin for profit by lowering O&M costs below nominal levels (or improving fuel efficiency). However, this is not treated explicitly. The debt : equity ratio is varied parametrically in the study, though the base case uses 4 : 1.[7] Depending on the loan duration and interest rate, there is a tariff interest component. Depreciation is taken as per the guidelines, 7.5% for 12 yr flat-line. The RoE is 16% for the life of the plant. It is assumed that the debt is paid off in equal annual installments over the life of the loan, based on an annuity formula. While the tariff reflects interest charges directly, the principal is not directly reflected in the tariff but accounted for through the depreciation component. The resulting equity schedule is converted to NPV at various discount rates. If internal rate of return (IRR) is used as the criteria for investment, this can be read off the NPV graphs as the discount rate which leads to zero NPV. As the proposed equity schedule assumes initial outlay of equity (throughout construction) and subsequent returns only, there is a unique solution to IRR.

Results

Table 3 summarizes the results of the model, for the cost of power and the returns enjoyed by the IPPs. The tariff that arises from the CEA guidelines is top-heavy. For the base case, the tariff in the early years (with depreciation and debt servicing occurring) is 5.70 and 7.64 cents/kWh[8]

[7] US nonutility power plants are assumed to have approximately 80% debt, i.e., 4 : 1 debt:equity (EIA, 1996b AEO97 Assumptions—based on a 1993 EIA sponsored study).
[8] These prices are in 1999 and 2001 dollars, respectively (see following section for explanation).

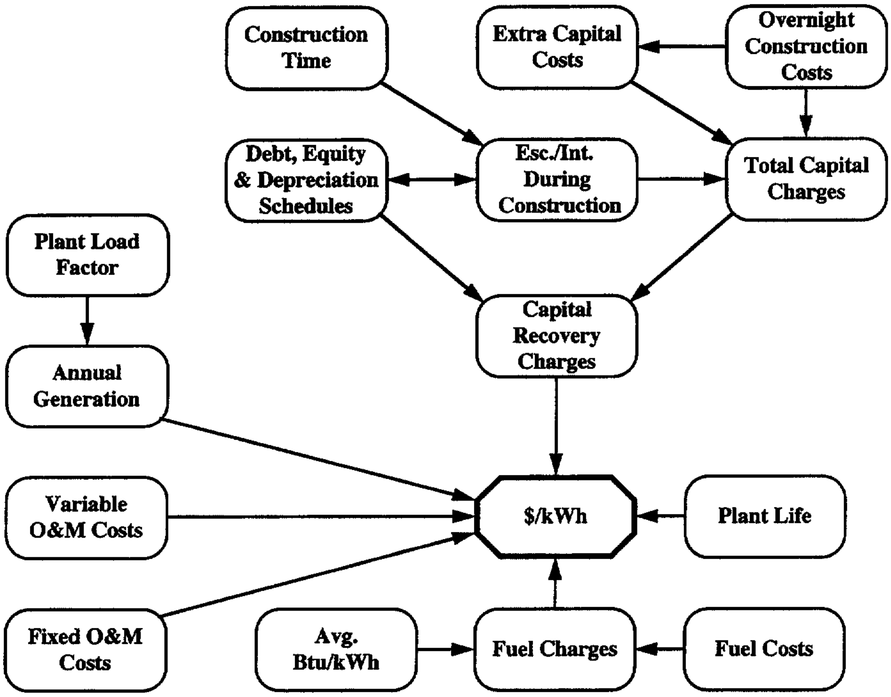

Figure 1 Simplified model for price of electricity. Return on equity, interest, and depreciation charges are all components of capital recovery charges. The price of power [$/kWh] is calculated as: (Capital Recovery Charges [$/kW] + Fixed O&M Charges [$/kW])/Total Generation [hours] + Variable O&M Costs [$/kWh] + Fuel Charges [$/kWh]. As the model deals with net heat rates, auxiliary consumption of fuel or power is not an issue. Not shown (or used in the model) are taxes, which are part of Fixed Costs.

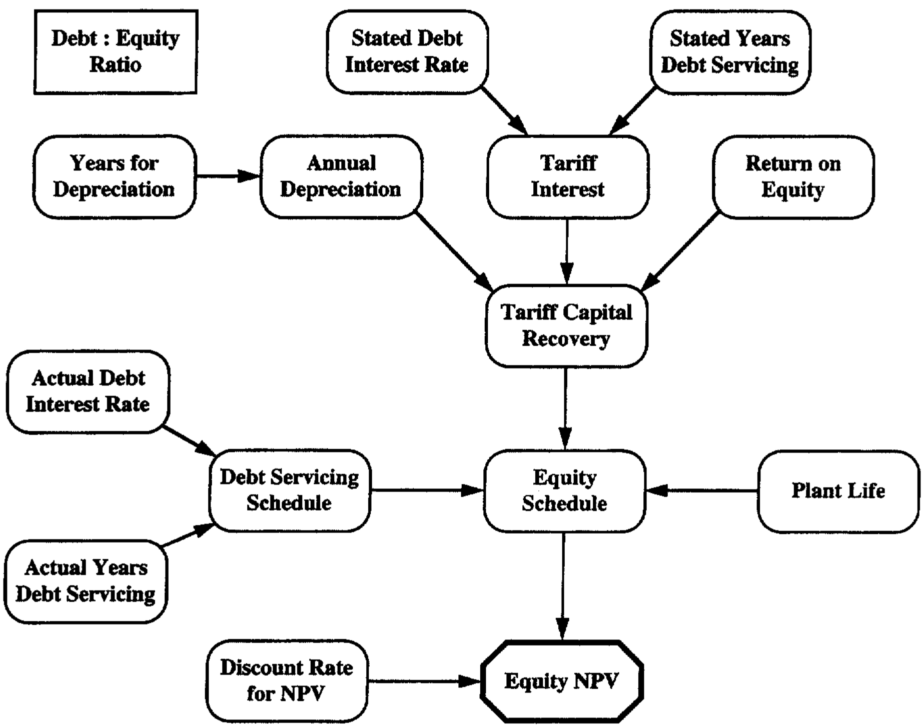

Figure 2 Simplified model for equity NPV. Debt : equity ratio affects the tariff interest component, return on equity component, debt servicing schedule, and equity outflow during construction (not shown). Based on the approved financial package, the tariff reflects interest charges, return on equity, and depreciation, the sum of which is the tariff capital recovery charges. Other components of tariff such as fuel, taxes, and O&M expenditures are pass-through, so are not expected to create cash for equity returns calculations. The equity cash flow is the difference between the tariff capital recovery charges and the debt servicing obligations. This cash flow includes the equity outflow during construction.

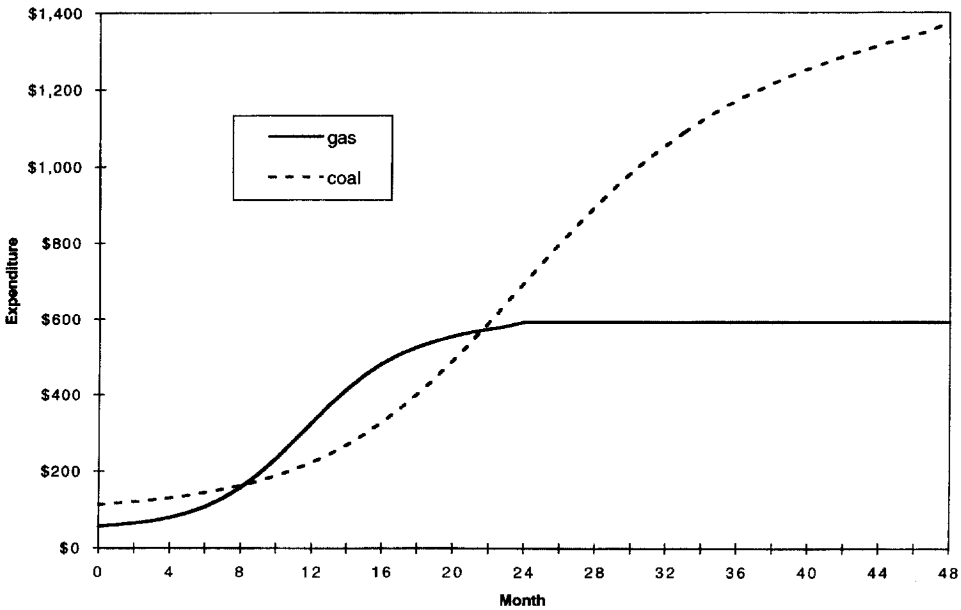

Figure 3 Cumulative construction outlay over time (modified logit curve). These curves include escalation and interest during construction. Construction times for gas and coal plants are 24 months and 48 months, respectively (other parameters are given in Table 1). The values do not reflect import duties (shown in Table 1).

Table 3 Levelized average cost of power and IRR

	68.5% PLF		80% PLF	
	Cost of power (¢/Rs. per kWh)	IRR (%)	Cost of power (¢/Rs. per kWh)	IRR (%)
Gas	5.27/1.87	30	5.10/1.81	36
Coal	6.68/2.37	24	6.35/2.25	28

Note: This assumes a 12 yr loan at 12% interest, 30 yr plant life, 12% levelizing rate, gas costs $4/MMBtu, coal costs $1.8/MMBtu, 4:1 debt:equity ratio, and CEA-based RoE bonus for generation above 68.5% PLF (other parameters are given in Tables 1 and 2). The above PLFs are assumed to extend throughout the life of the plant. The cost of power is in year of commercialization dollars, i.e.,1999 and 2001 for gas and coal, respectively (see text for explanation).

for gas and coal, respectively. This falls to 3.84 and 3.48 cents/kWh, respectively, after the end of this period. Table 4 shows the break-down of (early-year) tariff by component. For comparison, not only between coal and gas but between projects, the tariff must be levelized. CEA uses 12% or higher as a levelizing rate (Venugopal, 1997). Using such a high levelizing rate is a reflection of increased time value of money.

Nominal or real prices

As the escalation and interest rates are nominal, the levelized electricity costs calculated are all based on the year of construction completion, i.e., two years from 1997 for gas plants, and four years from 1997 for coal plants. The fuel and O&M costs are also for those years, and do not escalate in the model. While it is inconvenient to show gas and coal in different-year dollars, it is a non-trivial task to bring these into the same reference base. Different methods might include discounting coal to gas by two years (the difference in construction times) at the levelizing rate. However, that rate is very high. One could use the Wholesale Price Index, either in US or India. However, these vary from approximately 3% to 7% between the two countries. The price of electricity in India has been increasing on average by about 10% for the last 4 yr (Ministry of Power, 1997). However, that is

Table 4 Break-down of early-year tariff by components

	Gas (¢/kWh)	Coal (¢/kWh)
Debt	1.05	2.34
Depreciation	0.82	1.83
RoE	0.35	0.78
Total capital recovery charges	2.21	4.95
Fuel	3.01	1.75
Variable O&M	0.04	0.30
Fixed O&M	0.44	0.64
Total tariff	5.70	7.64
Breakdown of capital recovery charges		
Overnight construction costs	1.45	2.91
Land	0.001	0.021
Switchyard	0.06	0.06
Transit	0.07	0.15
Contingency	0.15	0.29
Escalation during construction	0.08	0.38
Interest during construction	0.19	0.85
Import duties	0.20	0.29
Total capital recovery charges	2.21	4.95

Note: This is for the base-case (Tables 1 and 2), and 68.5% PLF. The early-year tariffs include depreciation and debt charges; in later years, these end, increasing the relative share of equity and other components. A PLF over 68.5% would also raise the share of equity, due to the bonus RoE as per the CEA guidelines. The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).

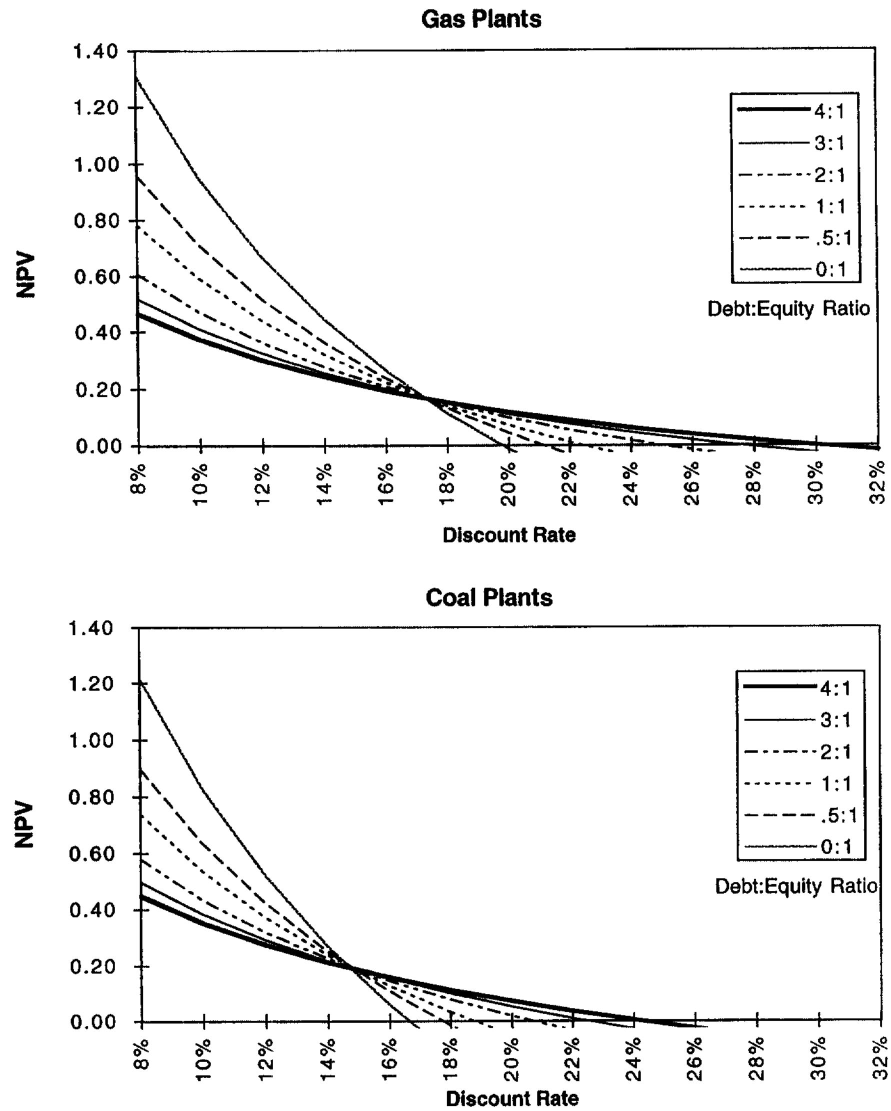

Figure 4 Equity NPV for various debt : equity ratios. This is the NPV per unit capital costs for base case conditions unless otherwise stated (Tables 1 and 2).

largely in an attempt to bring the prices closer to true costs to the SEBs, and does not directly reflect the increasing costs of power purchases by SEBs. One criteria for comparing coal and gas plant electricity might be the cost of power to the utility at a point in time. If a gas plant is completed two years from now, it will face 'competition' from a coal plant only after another two years. At that point, the price of power from the gas plant will only have increased by the increase in gas and O&M costs, as the capital charges do not escalate. Thus, the effective discount rate for coal to attempt to compare it with gas is very low.

The actual choice of gas versus coal for choosing projects is based not only the choice of the IPP, but also on availability of fuel. There is scarcity of gas in India (Ministry of Petroleum and Natural Gas, 1995), and so IPPs are likely to import LNG. While coal is also constrained by transportation bottlenecks, it is domestically available. In addition, coastal regions may find it attractive to import coal, the import duties on which were reduced to 20% recently. While geography remains a criteria in determining type of plant, average and peak power requirements of individual utilities, typical considerations when choosing type of plant, do not enter into tariff-setting calculations. We choose to leave the prices in different year bases, except when directly comparing coal and gas. We are more interested in trends in pricing and returns based on policy or financial choices.

NPV

Figure 4 shows the net present value of an investment in gas and coal projects for different debt : equity ratios. The highest debt : equity ratio (maximum gearing) offers the highest IRR, and the NPVs for gas plants are higher than for coal plants. These are for a normative level of generation, at 68.5% PLF. The first point to realize is that the nominal 16% return on equity is not the actual return on investment. The IRRs for our base case are significantly higher than 16%. In addition, the returns are likely to be

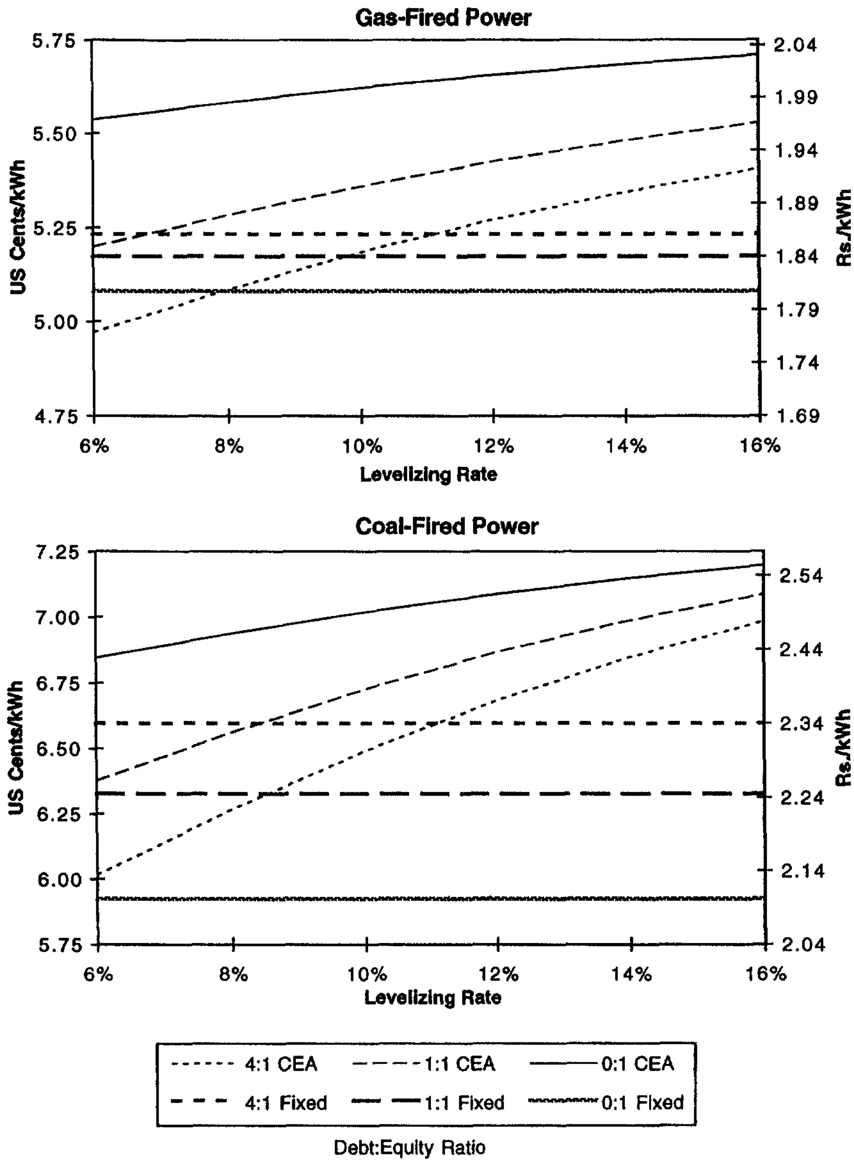

Figure 5 Levelized cost of power for CEA-based and fixed capital recovery charges. This is for base case conditions unless otherwise stated (Tables 1 and 2). The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).

even higher than for the base case due to a number of reasons, including fuel cost savings and higher PLFs. These are discussed in more detail later. Whether or not the tariffs are high is a matter of debate. The effect of high returns on equity is not as pronounced because of the relatively small share of equity in the tariff (the highest IRR is with the lowest equity component). For the base case (maximum gearing), gas plants have an IRR of 30% and 36% at 68.5% and 80% PLF, respectively. Reducing the IRR by one-third (to 20% and 24%, respectively) by lowering the *nominal* RoE would only result in a tariff reduction of approximately 5% and 6.5%, respectively (levelized @12%). The IRRs for coal plants are a good deal lower, and, due to the higher share of capital costs, a one-third reduction in IRR would lead to an approximately 10% reduction in tariff.

In addition to the CEA guidelines for calculating tariff, we have examined the returns and tariffs for different fixed capital recovery charges, ie, ones where the entire capital costs earn a constant (fixed) return for the life of the plant, with no separate charges for depreciation. For the base case, we have chosen 16% over the life of the plant. Such a tariff is uniform over the life of the plant, and is not a function of the levelizing rate. Figure 5 shows the effect of levelizing rates when the CEA method of tariff calculations is compared to a fixed capital recovery tariff. This latter method has the useful property of being a strong function of interest rates. The cheaper debt an IPP locates, the increased return on the equity component. Under the CEA guidelines, there are virtually no benefits to finding a cheaper loan. The benefit of cheaper debt is minimal, only due to the slight savings in repayment schedule. For comparison sake, the NPV based on fixed capital recovery charges for coal and for gas is shown in Figure 6.

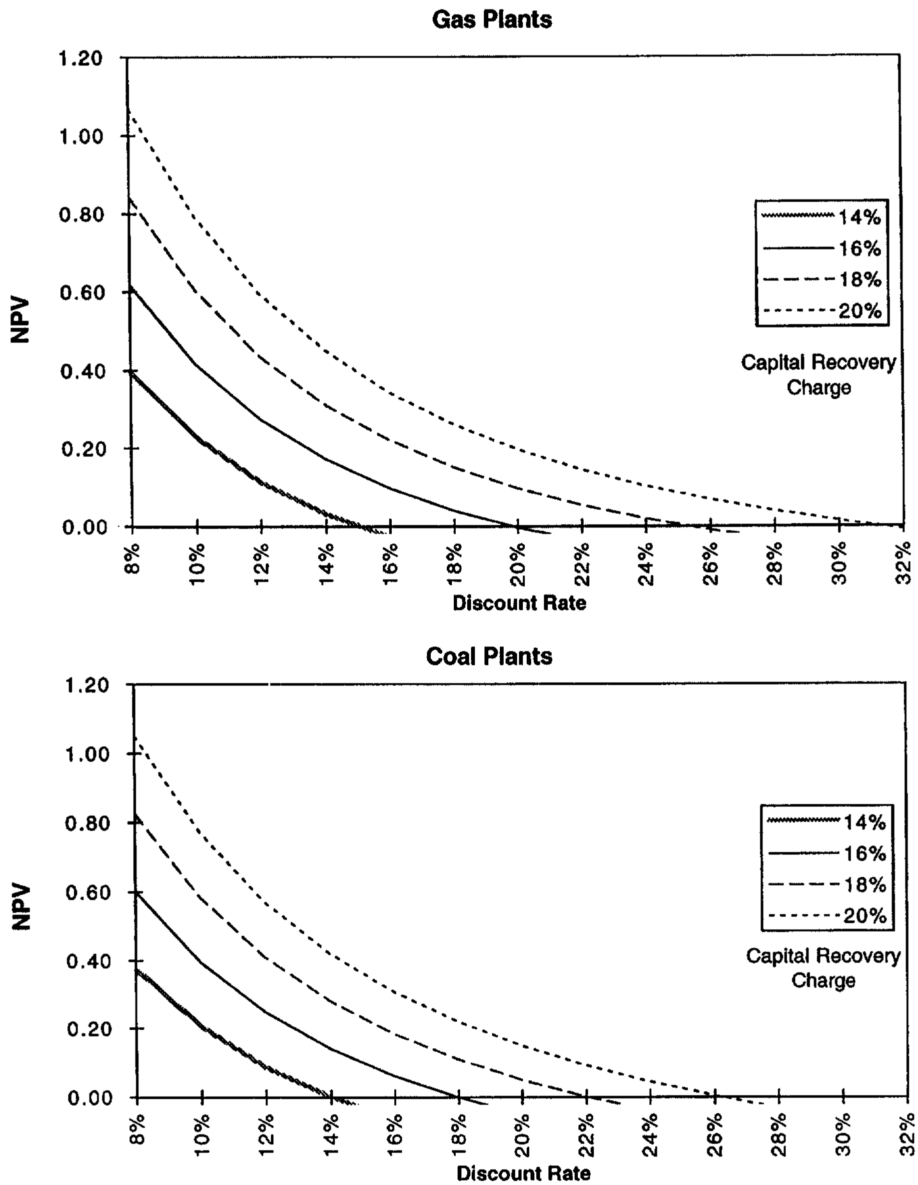

Figure 6 Equity NPV with different fixed capital recovery charges. This is the NPV per unit capital costs for base case conditions unless otherwise stated (Tables 1 and 2).

What factors matter

When examining the relative importance of parameters affecting the (levelized) price of electricity, there are two primary considerations. What is the relative effect of price with respect to input parameters (elasticity)? How much are the input parameters likely to vary? (The importance of levelizing rates is shown in Figure 5.) Clearly, due to the non-linear effects of input parameters, elasticities vary considerably with the point at which they are calculated. Importance analysis was performed using Latin Hypercube Simulation.[9] A uniform distribution across ± 10% was considered for the important input parameters. A simulation was performed for the levelized price of electricity, and the rank order correlation (Spearman's rank correlation coefficient) is shown in Figure 7. Table 5 shows the values used for the parameters.[10]

Price of electricity

For gas plants, the most important factors are fuel costs and heat rates (the product leads to the energy charges per kWh), followed by the plant costs (overnight construction costs). The PLF is an important *negative* factor, meaning the higher the PLF, the lower the cost of power.

[9] For a discussion of uncertainty analysis and Latin Hypercube Simulation, see Morgan and Henrion (1995).

[10] Strictly speaking, there is likely to be a correlation between the debt : equity ratio, debt interest rate, and the loan duration. However, as the study relies primarily on parametric variation of model parameters, the importance analyses assume independence of inputs parameters.

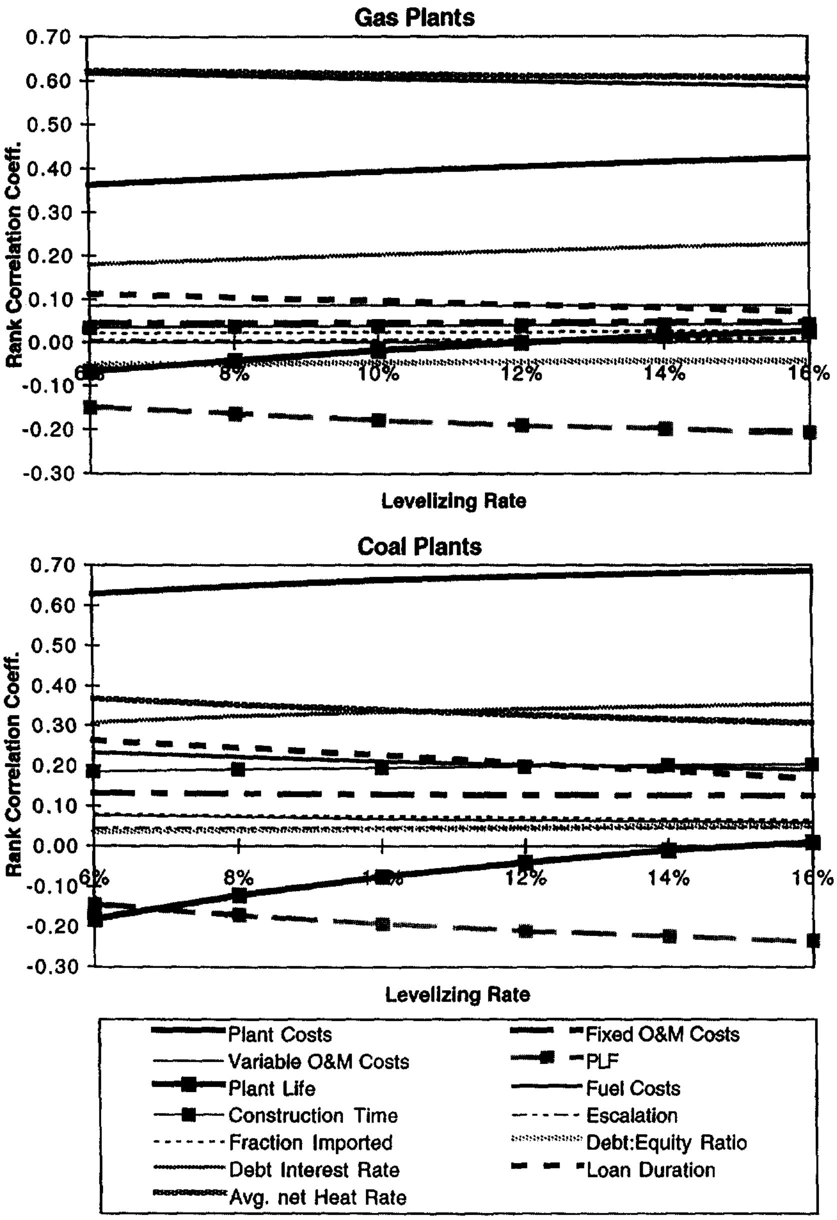

Figure 7 Importance analysis for levelized cost of power. Parameter values and ranges are given in Table 5.

The life of the plant is only somewhat important for low levelizing rates. For coal, the most important factor is plant costs, much more so than fuel costs and heat rates. The effect of PLF is similar, and the importance of plant life (negative factor) is more pronounced than for gas. Like gas, the debt interest rate is also more important than the duration of the loan. Debt: equity ratio is not a very important factor, but it is a negative factor for gas plants as in the base case, we are assuming cheaper debt than equity. However, for coal plants, this is more than off-set by the increased interest during construction, which only applies to the debt portion of the project. As expected, construction time is much more important for price of electricity from coal than from gas.

However, it is important to remember that this is based on the average input conditions. The relative importance of parameters will change across wider variation due to non-linear relationships. How much are the parameters likely to vary? That is a subjective matter, and often out of the hands of the IPP. While geographically determined, the price of coal is likely to vary less than gas, as the latter can have an administered (domestic) price of approximately \$2.5/MMBtu or an imported LNG price of approximately \$4/MMBtu.[11] Other parameters that might vary significantly between projects include the debt package, both interest rate and duration. While data are currently not available, an actual stochastic

[11] Based on conservative assumptions on heat rates, Enron's stated fuel charges after re-gassification (Parikh, 1996) work out to approximately \$3.75/MMBtu *in 1995 dollars*.

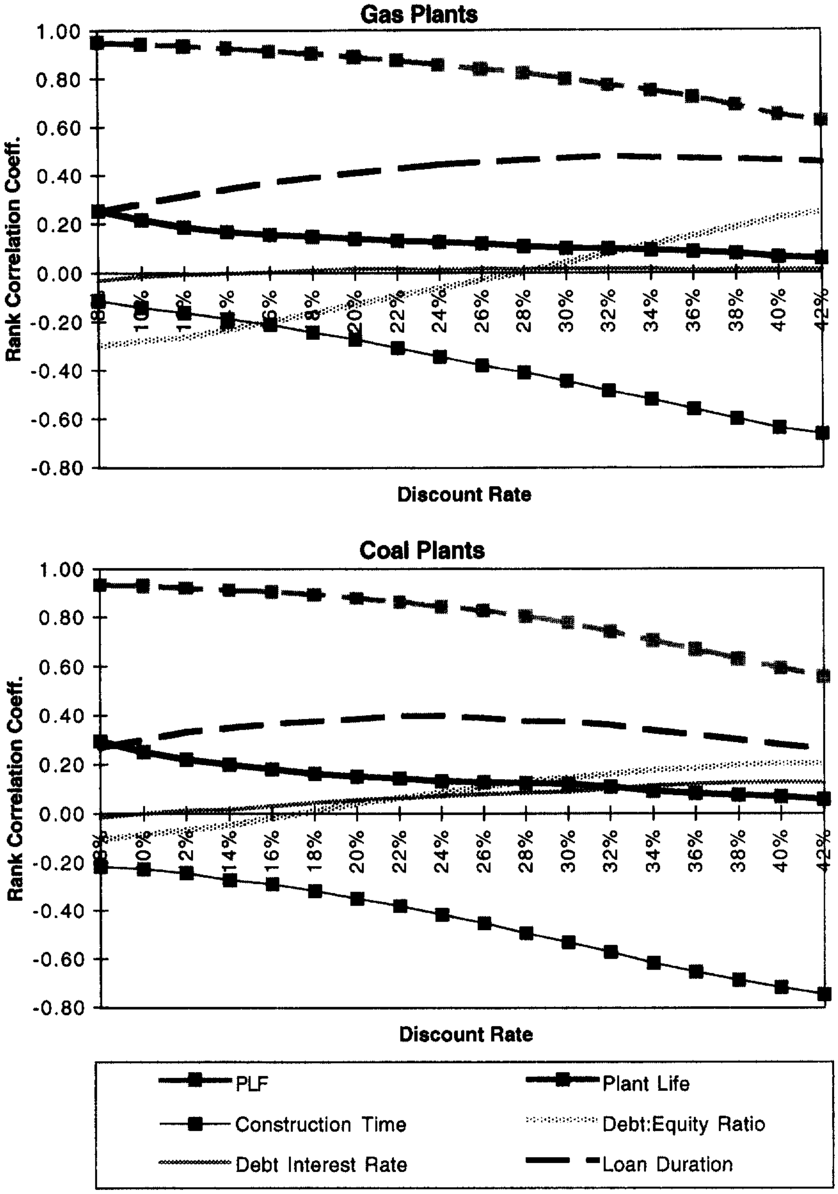

Figure 8 Importance analysis for NPV. Parameter values and ranges are given in Table 6.

model for price of electricity might include more accurate distributions for input parameters. For example, the overnight construction costs might include positively skewed distributions. However, the goal of this importance analysis is simply to show the relative importance of input parameters relating to price.

IPP NPV

Figure 8 shows a similar importance analysis for NPV. Table 6 shows the values used in the analysis. While the resulting coefficients vary between gas and coal, there are many similarities between the two. PLF is overwhelmingly the most important factor. This is because to an IPP, generation of power above the normative PLF earns more nominal RoE per kWh than power part of the normative level of generation, i.e., the first 6000 kWh. After this, construction time is an important (negative) factor, because of pro-rata equity and debt expenditure during construction. The loan duration is important, as the tariff reflects interest charges only during the loan duration. The effect of interest rate is much smaller, and almost zero for gas plants. Thus, there is little incentive to find cheaper loans, unless the company chooses to declare a higher loan rate than what it actually operates under. For the IPP, the life of the plant is not as important. We can see that debt:equity ratio, while not the most important factor, changes sign at some discount rate. At low discount rates, increased debt leads to lower returns, while at higher discount rates, increased gearing leads to increased returns.

Table 5 Importance analysis for levelized cost of power median parameters

	Units	Median value Gas	Coal
Plant costs	$/kW(net)	430	860
Fixed costs	$/kW/yr	26.5	38.6
Variable costs	¢/kWh	0.04	0.3
Plant load factor[a]		68.5–81.5%	68.5–81.5%
Plant life	yr	27	27
Fuel costs	$/MMBtu	3.5	1.8
Construction time	months	24	48
Escalation	per yr	4%	4%
Fraction imported		70%	50%
Debt:equity ratio[b]		3	3
Debt interest rate	per yr	12%	12%
Loan duration	yr	12	12
Avg. net heat rate	Btu/kWh	7520	9736

Note: This assumes a uniform distribution with $\pm$ 10% variation from the median value. Sample size 500.
[a] For PLF, the range is shown rather than the median value. This range is slightly less than 10% variation from 75%, the median value. This is to allow PLF to be above normative level of generation, i.e., allow full recovery of fixed costs.
[b] 4:1 debt:equity is the ceiling.

Table 6 Importance analysis for NPV median parameters

	Units	Median value Gas	Coal
Plant load factor		80%	80%
Plant life	yr	27	27
Construction time	months	24	48
Debt:equity ratio		3	3
Debt interest rate	per yr	12%	12%
Loan duration	yr	12	12

Note: This assumes a uniform distribution with $\pm$ 10% variation from the median value. Sample size 125 (highest computationally feasible). Similar to the values used for the importance analysis for levelized cost of power, the PLF was chosen at a higher value than 68.5%, such that there is full recovery of fixed charges.

Discussion

Returns on investment

The most striking feature of the results is that the IRRs are likely to be well above the nominal 16% RoE prescribed in the CEA guidelines. For the base case calculations (at 68.5% PLF), the IRR for gas projects is 30%, and for coal projects is 24%. The government guidelines allow for depreciation over 12 yr to be included as part of the tariff. While this is partly necessary to repay the principal amount of the loan (only the interest is part of the tariff for thermal power plants), this quickened amortization, resulting in a higher initial tariff, increases the returns for the investor. The expected life of the plant is likely to be 30 yr (EPRI, 1993), and even if an accounting life of 25 yr is taken, it is still significantly more than the 12 yr allowed by CEA guidelines for depreciation. The repayment of the loan will obviously require annual payments greater than the interest portion of the tariff. However, based on an annuity function (equal payments over the life of the loan), the amount necessary for loan repayment will depend on the interest rate *and* the term of the loan. For our base case of 12% loan for 12 yr, the necessary annual payment is 0.1614 per unit borrowed. However, when adding the depreciation to the interest, the tariff includes 19.5% as the cash generated in the tariff that is separate from the equity. As long as the loan is at such terms so as not to require a payment greater than the loan rate plus 7.5% every year (= 19.5% for the base case), there is incentive to increase gearing, increasing the effective cash available for return on equity.

What are the likely terms of the loans? It is difficult to say as IPP financial information is not public information in the US or India. However, one can make assumptions based on the capital market in the two countries. The prime lending rate in the US has been about 8.25% for a number of years (Federal Reserve, 1997). Utilities are able to raise money at bond rates, that too for reasonably long-term loans (30 yr). Assuming IPPs must pay more of a premium, 12% for 12 yr seems like a reasonable base case assumption. The Indian market rates are higher, with the State Bank of India prime lending rates recently reduced from 14% to 13.5% (Ministry of Finance, 1996). In addition, the loans are typically for a shorter duration, often 7 to 10 yr. For these cases, the annual repayment required is much higher, *and* the tariff will only reflect interest charges for a shorter period of time. The CEA depreciation allowance is more in tune

Table 7 Effect of different loan packages on cost of power and IRR

	8 Year, 16% Loan Gas	8 Year, 16% Loan Coal	12 Year, 12% Loan Gas	12 Year, 12% Loan Coal
IRR	24%	20%	30%	24%
Levelizing Rate	Cost of Power [¢/Rs. per kWh]		Cost of Power [¢/Rs. per kWh]	
6%	5.01/1.78	6.20/2.20	4.97/1.77	6.02/2.14
8%	5.14/1.83	6.52/2.31	5.08/1.80	6.27/2.22
10%	5.27/1.87	6.81/2.42	5.18/1.84	6.49/2.30
12%	5.38/1.91	7.06/2.51	5.27/1.87	6.68/2.37
14%	5.48/1.94	7.29/2.59	5.34/1.90	6.85/2.43
16%	5.56/1.97	7.49/2.66	5.41/1.92	6.98/2.48

Note: This assumes a 68.5% PLF, 30 yr plant life, 12% levelizing rate, gas costs $4/MMBtu, coal costs $1.8/MMBtu, and 4:1 debt:equity ratio (other parameters are given in Tables 1 and 2). The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).

with a 10 yr loan at 15%, which needs an annual repayment of 19.9%. In such a case, some of the equity component depreciation is needed to repay the loan.

One can compare the effect of having a 12 yr loan at 12% versus an 8 yr loan at 16% (Table 7). Clearly, access to longer-term loans at a lower rate is in the interest of the IPP and, in many cases, the utility.

Based on our interpretation of the guidelines, for a given loan interest rate, a longer repayment period decreases the debt servicing requirements for the IPP, while simultaneously raising the tariff. Clearly, CEA (or other regulatory agency) would not approve a 30 yr loan at 12% when the depreciation allowance adds to the cash flow of the IPP. However, from the utility point of view, fixing the length of the period during which interest is charged into the tariff at a constant level keeps the tariff manageably low. After that point, it should be up to the IPP to take longer to pay back the loan (if it is able to do so). This brings us to the point of verification of loan schedules. In practice, if a large multinational IPP firm claims a certain debt structure, it is both difficult and expensive to verify this. There is all the incentive for the IPP to 'lie' in stating that the interest rate is higher than what they have really been charged. For companies with multiple projects under debt financing, it can be difficult to separate the debt rates for the projects. More likely, even without lying, it is not unreasonable for a company to refinance its debt at more attractive terms and not pass on the benefits to the SEBs. If there truly were competition between IPPs for power purchase agreements, then, all other things being equal, an IPP with the longer period loan would be able to bid for a lower price while still achieving the same IRR, or keep the same price and receive a higher IRR.

The rule that debt and equity expenditure during construction must be pro-rata might explain why, despite limited availability of natural gas in India, there is considerably more interest in natural gas plants than coal plants. As coal plants' construction is expected to take longer, there is earlier outlay of equity capital, which does not accrue interest during construction. This reduces the IRR.[12] Clearly, in terms of capital costs only, utilities would favor increased equity share, reducing the interest during construction. However, IPPs would like to spend equity later during construction (especially as they can capitalize IDC). It is difficult to know exactly what the construction schedules will be, and what is expended when. For a large company, debt and equity are simply cash sources. An IPP can arrange a short-term loan (undisclosed to CEA), perhaps at 2% above the debt interest rate, to pay for equity cash requirements during construction. For base case calculations, they will raise their IRR from 30% to 34% and 24% to 30% for gas and coal projects, respectively, *without increasing the tariff.*

This simply shows that any tariff-setting structure which is a function of debt: equity choices will be treated differently by different companies, depending on their finances. If IPPs can arrange credit with suppliers to pay for equipment a few months later than as per the CEA approved package, that is also to their benefit.

Current depreciation policy is to have a depreciation schedule spelt out in the guidelines,[13] resulting in 7.5% per annum for the plant overall, for a period of 12 yr, reaching 90% depreciation (with 10% salvage value). However, this quickened straight-line depreciation in itself raises the return on equity because of the time value of money. Our understanding is that depreciation should be part of the expenses *for tax purposes*, and need not be part of the tariff. Removing depreciation from the tariff (while allowing for loan repayment including the principal) would result in a lower tariff. If depreciation still is to be included, extending it to 25 or 30 years would also lower the levelized cost of power.

More importantly, the fact that depreciation is part of the tariff directly raises the IRR. IRR already accounts for the fact that there was an initial expenditure generating returns over time. A simple example will show the relationship between nominal return on equity and IRR. Say we are considering a one-time $100 (or Rupee) investment, that will give us a 16% nominal return on equity for 30 yr. This leads to an internal rate of return of 15.8%. Not quite 16%, because there was the initial investment. However, the IRR is not lower than 16% by 1/30, which is what a simplistic (but incorrect) application of flat-line depreciation over the life of the project would imply. In fact, if one looks at an annuity function, one which will pay off a $100 loan over 30 yr at 16%, the annual payment is only $16.19. For a simplified example with only an equity investment of $100 (expended through-out the construction period), the tariff would reflect $16 as RoE charges per year (at normative level of generation), and, for the first 12 yr, $7.5/year as depreciation charges. Such a tariff would lead to an IRR of 20%.

If the goal of the CEA is to actually provide a cost-plus tariff structure, it can even attempt to give a fixed IRR. For a tariff structure as intrusive as this, the tariff can do away with depreciation altogether, accounting for the exact debt servicing schedule and setting the tariff so as to allow a net IRR of 16% (or higher if that is deemed necessary for ensuring investment). However, we do not recommend this, as one of the strongest complaints of the CEA guidelines is their intrusive nature.

Debt: equity choices

Debt: equity ratio is a choice that a company makes based on market realities. In an idealized world, the two

[12] Other reasons for interest in natural gas plants are their higher expected availability, shorter construction times, and lower environmental concerns.

[13] The entire depreciation schedule is tedious, with different rates for different components. For example, land has an infinite life, and does not depreciate. The main components have allowed values of 7.84% or 8.24%, depending on the equipment. This leads to an overall plant value of 7.5%.

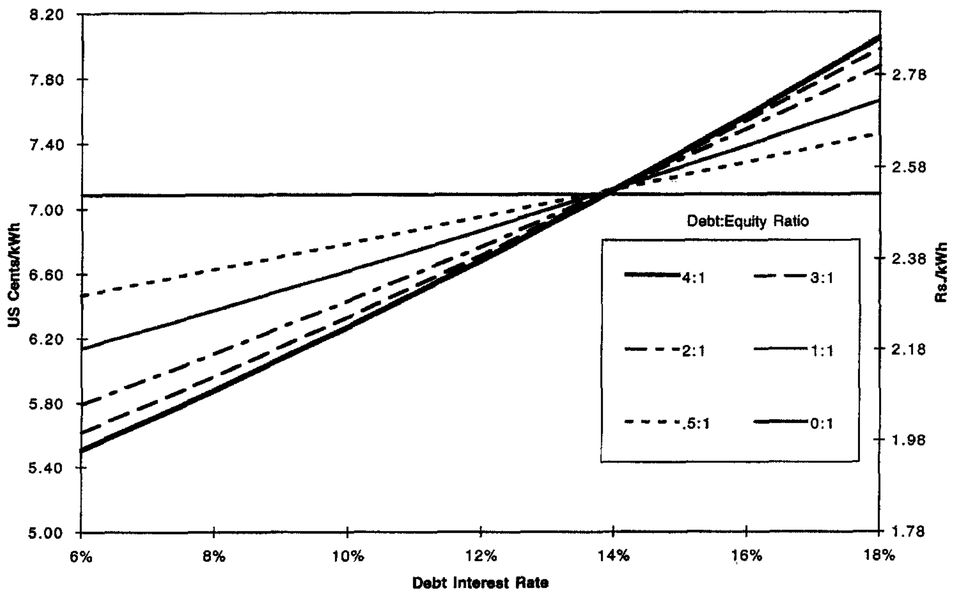

Figure 9 Levelized cost of power from coal plants based on varying debt rates and debt: equity ratios. This assumes 68.5% PLF, 12% levelizing rate. Other parameters as per base case (Tables 1 and 2). The cost of power is in year of commercialization dollars, i.e., 2001 dollars (see text for explanation).

would be treated indifferently, as has been shown by Modigliani–Miller (Carstairs and Ehrhardt, 1995). However, 'Capital structure is irrelevant *as long as the firm's investment decisions are taken as given*' (our emphasis) (Brealey and Myers, 1996, p. 447). In the case of the CEA guidelines, both expenditure (construction outlay) as well as revenue streams are different for different capital structures. Thus, we must examine the choice of debt:equity from the IPP's point of view.

CEA guidelines allow a 16% return on equity. Debt servicing is done on an actual basis, i.e., the tariff reflects whatever the project borrowing interest rate is. However, as the money can be borrowed in US$, with repayments (up to normative level of generation) allowed in foreign exchange, it is typical for debt interest rates to be lower than 16%. Thus, it is to the advantage of the utilities to have a moderately high debt portion in the capital structure. However, there is a trade-off involved, as increased debt leads to increased IDC.[14] The comparative effects for the utility are shown in Figure 9.

When examining the NPV of equity as a function of debt: equity ratios, we see that the highest IRR is with maximum allowed gearing, i.e., a 4:1 debt: equity ratio. However, there is a cross-over point, a discount rate below which a higher NPV is achieved by *lower* gearing.[15] It remains to be seen whether or not this cross-over point is above or below the company's chosen discount rate for evaluating the project capital structure.[16]

$$\text{Company cost of capital} = \frac{D}{V} r_{debt} + \frac{E}{V} r_{equity} \qquad (1)^{17}$$

where

D = debt
E = equity
V = value = debt + equity
r_{debt} = debt discount rate
r_{equity} = equity discount rate

Taking 4:1 debt: equity ratio, r_{debt} as 12%, we can then evaluate a reasonable cost of capital based on the equity discount rate. Even if r_{equity} is taken as 30% (the IRR we have calculated for our base case gas plants), the company cost of capital comes out to 15.6%.[18] For coal plants, taking r_{equity} as 24% brings the cost of capital (with full gearing) to 14.4%, which is just below the

[14] Government projects in India have a typical debt: equity ratio of 2:1 or 2.33:1. However, certain public sector corporations have demanded a 1:1 ratio. Increased government equity would result in lower IDC, more so for the case of coal or nuclear power, which have long construction times.

[15] As long as there is no capital rationing, companies are better off maximizing NPV at an appropriate discount rate, rather than maximizing IRR (Brealey and Myers, 1996).

[16] The NPVs calculated in this study are all per unit capital costs. This NPV can be multiplied by the total capital costs to obtain the equity NPV in dollars (or Rupees). The interest during construction varies with debt: equity ratio, so the total capital costs are not the same for different debt: equity ratios. However, this does not affect the relative shapes of the NPV curves significantly, e.g., the cross-over points.

[17] See Brealey and Myers, (1996, p. 214)

[18] Applying the capital asset pricing model is difficult because the market premium would be different for different countries. An analysis of 17 large utilities in the US from 1990–1994 shows a portfolio β of 0.47, with a Standard Error of 0.09 (Brealey and Myers, 1996, p. 219). Based on 1995 numbers, that implies an equity discount rate of about 10%. Is this to mean that a US power company investing in India would take 10% as the cost of equity capital? The likely answer is no, as the *project's* riskiness is likely to be higher. However, due to an undeveloped private power sector in India, it is virtually impossible to accurately determine what β should be.

cross-over point. Thus, at this set of parameters, IPPs might be more interested in a higher equity component than full gearing. The exact effect of any capital rationing as well as varied debt rate or tax profile must be calculated on a case-by-case basis.

PLF & incentive

So far, we have not considered the level of generation. By the CEA guidelines, there is full recovery of fixed charges at a normative level of generation, currently fixed at 6000 kWh/kW/yr. Above normative levels of generations, the tariff does not include any charges towards fixed costs, except a bonus RoE as per the CEA guidelines. The higher the normative PLF, the lower the cost of power will be. However, setting the normative PLF too high might result in incomplete recovery of fixed charges.

Whatever the normative PLF may be for full recovery of capital charges, there arises the issue of how to price the power that is purchased (sold) above this point. Consider if any additional power is purchased at simply the marginal cost (fuel + variable O&M, which is currently not part of the CEA guidelines). That would be the cheapest power that the utility (SEB) can buy. However, from the producer's point of view, this 'extra' power would not earn any return on equity.

The CEA guideline for extra power is to give an incentive for a higher PLF than normative, 0.7% additional RoE for every increased percentage of PLF. However, the way this is set up, the bonus RoE from an extra kWh over 6000 kWh is worth more than the regular RoE from a single (normative) kWh. Depending on the debt: equity ratio, as well as the year (whether depreciation and loan payment are over), a single kWh over the 6000 hr point ('extra power') could cost more to buy than the kWh that makes up the normative level of generative ('normative power'). For our base case, in the early years (with loan payment and depreciation as part of the tariff), extra power is cheaper than normative power by 1.6 and 3.3 cents/kWh for gas and coal, respectively. However, as the equity share increases, extra power becomes more expensive than normative power. This would occur at a little under 1:1 debt:equity ratio. For the later years, when depreciation and interest charges are no longer part of the tariff, there is no level of gearing which makes extra power cheaper than normative power.

The bonus RoE for higher PLFs increases the IPP's incentive for increased equity share. Looking at the NPVs for gas and coal plants (Figure 4), we see cross-over points for NPV versus discount rate, below which lower gearing leads to higher NPVs. While the cross-over points are approximately 17% and 15% for gas and coal, respectively, at 68.5% PLF, these increase to 24% and 19%, respectively, at 80% PLF. Increased equity generally increases the cost of power, not only because of bonus RoE for higher PLFs, but also because the 16% RoE is likely to be higher than the cost of debt. This shows that the utility would not always want extra power above the normative level of generation, at least based on the CEA guidelines of bonus RoE. One other concern is that the high bonus for generation above the normative level would increase the incentive for IPPs to understate their capacity, and thereby operate at high PLFs.[19]

From the utility point of view, extra power should be cheaper than normative power, as the loan, depreciation, and fixed O&M are already covered (here, we are considering the early years of generation). Clearly, they can pay some additional return on equity, and still find it cheaper than buying normative power. One level of bonus RoE might be to reward each additional kWh with the *same* RoE as normative power, namely, 0.16/6000, or 0.23% additional RoE per percent additional PLF. The actual bonus chosen can be within a range, while the above framework is a suggestion. The lower bound for this range would be for zero bonus RoE. The cost of extra power would then be as low as possible, but there would be little incentive for the IPP to go in for additional generation (except for heat rate and other hidden savings, discussed later). The upper bound for the bonus would be that which would make the cost of extra power the same as the cost of normative power. This is not favorable from the utility point of view. The CEA guidelines for RoE fall above the proposed framework, and depending on the share of equity, above the upper bound! The pricing of this extra power can be thought of as an economic rent problem. A solution that gives both the producer and the consumer some of the benefit should be acceptable to both. This framework would allow both the utility to gain (more extra power means lower average costs) as well as the IPP (higher RoE). The CEA guidelines allow for a very high nominal RoE at 90% PLF, equal to over 14% more than the 16% nominal at 68.5% normative level of generation. Under the suggested alternative framework, a 90% PLF would lead to a nominal RoE of a little over 5% more than at normative PLF. It is important to remember that up to the normative level of generation, this is post-tax, in US$ (or whatever currency is used for the equity).

Coal vs gas

The actual PLFs will (should) depend on the demand profile. A 90% PLF should only be the case for a base-load plant.[20] For argument's sake, let us assume that all

[19] Such a phenomenon is not restricted to the power sector. Examination of the Indian fertilizer sector by Parikh (1997) shows considerable understatement of capacity. This sector also operates on a cost-plus basis, with a normative plant capacity utilization factor of 90%. Parikh found the weighted average capacity utilization for nitrogenous fertilizer plants in 1995–96 was 122%, resulting in significantly higher returns than normative.

[20] Gas plants are likely to have higher availabilities, and thus potential PLFs. It is estimated that a gas plant will have a downtime of 15 days/yr, while a coal plant, 30 days (EIA, 1996a).

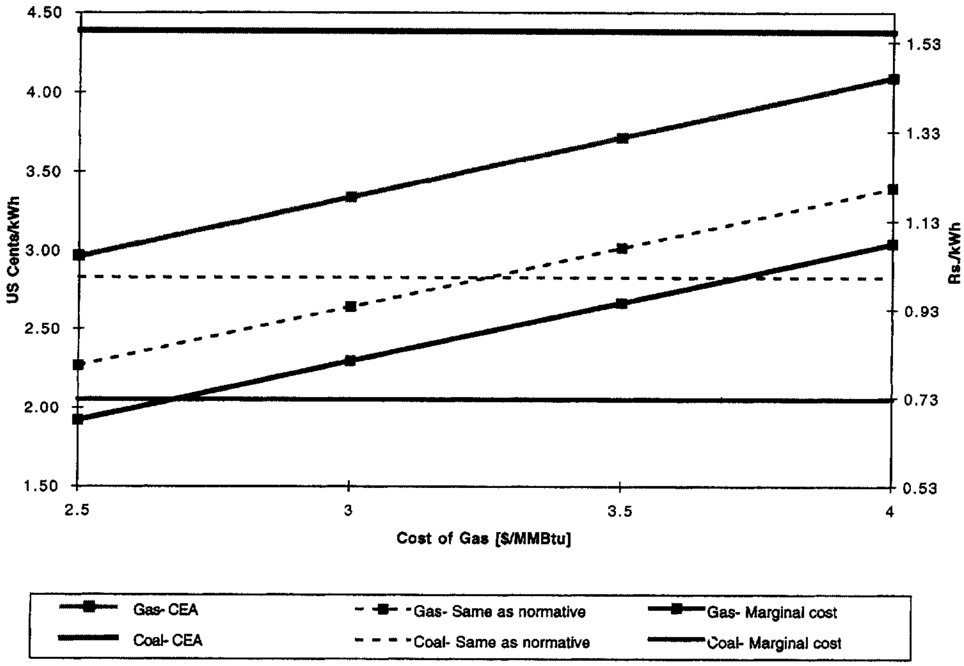

Figure 10 Cost of power above normative level of generation. This shows the cost to the utility for power purchased after fixed costs are recovered. RoE for such power could be as per CEA guidelines, at the same level as for normative power, or zero (i.e., marginal cost). The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).

plants that have an availability over 68.5% also have a PLF over 68.5% (or whatever the normative level may be). Thus, the fixed costs are accounted for. For the periods of peak demand, which should be the plants that supply this extra power? Based on likely ranges for values and calculations for gas and coal plants, the average cost of (normative) power from gas plants is likely to be lower than for coal, but the marginal (incremental) cost of power for gas is likely to be higher, due to the higher fuel costs.[21] As the fixed cost are already covered, from the utility point of view, the proper despatch would be to buy power from the type of plant that would sell it at the lowest rate. In this case, that would not quite be marginal cost, because of the bonus RoE, whatever that might be (CEA guidelines, above framework, or something else). Figure 10 shows the cost of power above the normative level of generation to the SEB based on different gas costs and bonus RoE methods. We can see that for the CEA method bonus RoE, for all likely ranges of gas costs, gas-based power beyond normative generation is *cheaper* than coal-based power. As we are largely considering imported gas for new IPP projects, the price of gas is likely to be on the higher side of the range indicated.[22] The price of coal is likely to fall in a narrower range. The effect on average cost of power above the normative level of generation is shown in Table 8.

Table 8 Levelized cost of power at 80% PLF

	CEA guidelines (¢/Rs. per kWh)	Raising the normative PLF to 80%[a] (¢/Rs. per kWh)
Gas	5.10/1.81	4.95/1.76
Coal	6.35/2.25	6.02/2.14

Note: This assumes a 12 yr loan at 12% interest, 30 yr plant life, 12% levelizing rate, gas costs $4/MMBtu, coal costs $1.8/MMBtu, and 4:1 debt:equity ratio (other parameters are given in Tables 1 and 2). The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).
[a] Equivalent to paying marginal costs over 68.5% PLF.

Under the CEA guidelines, if gas and coal plants compete for extra power, the utility would favor gas-based power. This would mean the gas-based producer receives a nominal RoE over 16%, while the coal producer only receives the nominal 16% RoE. At this point, the coal producer can *voluntarily* offer to sell power at a price lower than the prescribed bonus RoE + variable costs + fuels costs. In fact, being bound by the marginal cost, the coal-based IPP can bid anything low enough to be cheaper than the gas plant, while still attaining a higher RoE. The same tactic is available to the gas-based IPP. This would lead to a pseudo-market pricing mechanism (only applies to power beyond the normative level of generation). While the exact case for which plant offers cheaper extra power depends heavily on the price of fuel, which is ostensibly out of the company's hands, the other details of the project financing and capital matter. How is the SEB to know what the true costs of additional power are? It can ask for bids for the extra power.

[21] This is not a phenomenon of Indian conditions. Ellerman (1996) shows the increased use of coal for incremental generation in the US is the result of sunk costs when considering peak versus off-peak generation.
[22] For comparison, US power producers pay approximately $2.3/MMBtu for their gas (EIA, 1996a).

Table 9 Effect of varying coal plant overnight construction costs on cost of power

		Average levelized cost of power			Cost of extra power (above normative) for various RoE methods		
Overnight construction costs ($/kW)	**Total plant investment** ($/kW)	**68.5% PLF CEA** (¢/kWh)	**80% PLF CEA** (¢/kWh)	**Raising normative to 80% PLF** (¢/kWh)	**CEA** (¢/kWh)	**RoE same as normative** (¢/kWh)	**Marginal cost** (¢/kWh)
700	1197	5.96	5.67	5.40	3.97	2.69	2.05
750	1280	6.18	5.88	5.59	4.10	2.74	2.05
800	1363	6.41	6.10	5.78	4.23	2.78	2.05
850	1446	6.64	6.31	5.98	4.36	2.82	2.05
860	1463	6.68	6.35	6.02	4.39	2.83	2.05

Note: This assumes base case parameters, unless otherwise noted. The cost of power is in year of commercialization dollars, i.e., 2001 dollars (see text for explanation).

Table 10 Levelized cost of power from coal plants based on varying construction and fuel costs

	Cost of coal ($/MMBtu)				
Overnight construction costs ($/kW)	**1.2** (¢/kWh)	**1.4** (¢/kWh)	**1.6** (¢/kWh)	**1.8** (¢/kWh)	**2.0** (¢/kWh)
700	5.37	5.57	5.76	5.96	6.15
750	5.60	5.79	5.99	6.18	6.38
800	5.83	6.02	6.22	6.41	6.61
850	6.05	6.25	6.44	6.64	6.83
860	6.10	6.29	6.49	6.68	6.88

Note: This assumes base case parameters and 68.5% PLF, unless otherwise noted. The cost of power is in year of commercialization dollars, i.e., 2001 dollars (see text for explanation).

Table 12 Potential IRR using superior heat rates than nominally stated in CEA guidelines

	68.5% PLF		80% PLF	
Debt:Equity	2:1	4:1	2:1	4:1
Gas	30% (25%)	38% (30%)	37% (31%)	45% (36%)
Coal	22% (21%)	26% (24%)	27% (25%)	30% (28%)

Note: This assumes the tariff is set according to CEA guidelines heat rates while the actual heat rate is superior. The numbers in parentheses are the IRRs using (and charging based on) the base case heat rates (Table 2). This assumes a 12 yr loan at 12% interest, 30 yr plant life, gas costs $4/MMBtu, and coal costs $1.8/MMBtu (other parameters as per Tables 1 and 2).

Much of the analysis has shown that coal is not likely to be competitive with gas. However, there are indications that the capital costs of coal will depend on whether the equipment is Indian or imported, and what level of environmental controls are required. In addition, the price of coal will vary mainly with distance from the pithead. Table 9 shows the effect of varying the coal plant's overnight construction costs on cost of power. Table 10 shows the effect of varying coal prices on cost of power.

CEA guidelines: other issues

Jones (1991) states that one of the two biggest risks with large infrastructure projects is that capital costs might be higher than expected. This is more so with maturing technologies than mature technologies. Looking at the guidelines, there are attempts to reduce such risks for the investor. If the actual expenditure (whether construction or operating) is higher than projected, the tariff will reflect that (subject to CEA approval). The other major risk with such large projects is demand for output.

Recent moves by the CEA indicate that the level of electricity generation would not be based on actual generation but on availability. Specifically, if an IPP is told to back down by the Regional Electricity Boards, that is 'deemed generation'. There is no benefit in paying for electricity that is not used. In addition, newer plants, especially gas-based ones, are likely to have a very high availability. We strongly suggest other policies for ensuring recovery of fixed costs, if that is the rationale for such a move. If this is being done to increase investors' returns, then it is suggested that be done separately and explicitly.

A criticism of the CEA guidelines is that they attempt to dictate operating parameters. By making fuel, loan, etc., all passed through into the tariff, that reduces the

Table 11 Comparison of nominal CEA heat rates with known market heat rates

	CEA heat rate (gross) (Btu/kWh)	**Auxiliary consumption** (%)	**Net CEA heat rate** (Btu/kWh)	**1993 US (model) net heat rate**[a] (Btu/kWh)
Gas	7937	3	8182	7520
Coal	9921	8[b]	10783	9756

Note: Newer commercial plants are likely to have superior heat rates than those used in the model, especially newer combined-cycle gas turbine plants.
[a] *EPRI-TAG 93*.
[b] Steam driven pumps.

Table 13 Levelized tariff based on different heat rate assumptions

	Model heat rate[a] (¢/Rs. per kWh)	Nominal CEA heat rate (¢/Rs. per kWh)
Gas	5.27/1.87	5.54/1.96
Coal	6.68/2.37	6.87/2.44

Note: This assumes base case parameters (normative 68.5% PLF), unless otherwise noted. The cost of power is in year of commercialization dollars, i.e., 1999 and 2001 for gas and coal, respectively (see text for explanation).
[a] Based on *EPRI-TAG 1993*.

incentive of the IPP to find less expensive fuel and debt. In addition, CEA states what the heat rates should be for the plant, at least in terms of tariff. While a bound is useful, it does not reflect technological improvements. Table 11 shows the difference between nominal CEA and commercial heat rates.

The difference between the model and the nominal CEA heat rates is quite significant, 662 and 1047 Btu/kWh for gas and coal, respectively. Given higher fuel costs for gas in $/MMBtu, this implies potentially significant extra earnings. In fact, if the IPP were able to pocket this difference, the tariff would be higher than calculated in the model, as would the IRR. This would be an incentive to increase gearing, and also find *more expensive* fuel. Table 12 shows the effect of such a heat rate bonus on IRR. However, we are uncertain whether IPPs will claim to only use nominal heat rates or superior ones (especially in the case of gas plants). Thus, our model assumes superior heat rates rather than as per CEA guidelines. The NPV importance analysis shown in Figure 8 also does not account for possible variations (improvements) in actual versus stated heat rates.[23] While some level of superior operation incentive is standard, the possible heat rate benefits are not unlike the benefits available to companies that can construct plants at a lower $/kW price than what the CEA accepts in their project review. Such cost reductions are not passed on to the consumers. The effect on tariff if nominal CEA heat rates are used is shown in Table 13.

There are concerns that poor grid discipline and despatch will result in significant low-load demand, leading to poor heat rates. Based on heat rates at various loads (EPRI, 1993), we calculated possible average heat rates across a wide variety of load, availability, and generation levels. The assumed average heat rate corresponds to an average load of approximately 75%. Such an average value can approximate a variety of load conditions. As an example, consider a plant generating 6000 kWh/kW but which is on for 85% of the time. If it operates only at full load or 50% load (day and night), it would operate at full load for 52% of the time, 50% load for 33% of the time, and be off for the remaining 15% of the time. Even such a non-optimal loading would result in an average net heat rate of 7546 and 9722 Btu/kWh for gas and coal plants, respectively, not very different from the assumed averages (Table 2).

The last concern we discuss here is the complexity and the scope for manipulation in the CEA guidelines. Even without deception, the perception of unfair practices can be a powerful obstacle to smooth and rapid establishment of generation capacity. In our calculations, we find that the IRR increases significantly if the actual loan package is at a lower rate and/or for a longer period of time than stated (the latter does not affect tariff, though). Such changes might not even be purposeful manipulations; the loan package might be refinanced. This incentive to inflate costs is just one of the many negative aspects of a cost-plus mechanism.

As an example of why we feel the rates of return as per the CEA guidelines are very generous, consider an IPP which states a 12 yr, 12% loan and goes for a 4:1 debt:equity ratio. If the IPP uses short-term borrowing at a 2% premium (= 14%) to cover the equity cash requirements during construction and is able to operate at 80% PLF, the CEA guidelines would provide for an IRR of 41% and 36% for gas and coal plants, respectively. In addition to this, if the IPP is able to set the tariff using CEA heat rates, but actually operates on the model heat rates, the IRR would rise to 54% and 39% respectively.[24]

Policy and conclusions

The existing CEA guidelines are ambiguous, and appear to offer room for maneuvering (legal and otherwise) for investors. The expected IRRs are likely to be significantly higher than the nominal 16% RoE, which we calculated for our base case to be 30% and 24% for gas and coal-based plants, respectively. The other concerns with the CEA guidelines are:

- little incentive for IPPs to find cheaper loans,
- no benefits of technology improvement for consumers,
- no benefits for IPPs for reducing capital costs,
- loan package affects IRR significantly,
- gas appears more attractive to the IPP than coal, despite being limited in availability,
- the bonus for RoE above normative generation is high, reducing the benefits to consumers from base-load plants.

In addition, there is an unwelcome incentive for the IPP to inflate costs, the loan package or operating

[23] Adding such a heat rate bonus to the NPV importance analysis changes the values for other parameters. Heat rate is now the most important characteristic for gas plants NPV, followed by PLF. For coal plants NPV, PLF is still the most important, while heat rate is amongst the more important.

[24] However, this last move would result in higher tariffs than calculated in the model. Comparing the gas and coal-based tariffs levelized @12% for 80% PLF with or without such a heat rate bonus, the tariff would be 5.10 ¢/kWh versus 5.37 ¢/kWh for gas plants, and 6.35 ¢/kWh versus 6.54 ¢/kWh for coal plants. These prices are in 1999 and 2001 dollars for gas and coal, respectively (see section on real versus nominal prices for explanation).

parameters. This increases the returns for the investor at the expense of the consumer. Whatever cost reductions/operation improvements are made are likely to benefit the IPP, rather than being passed on to the consumers.

While the returns calculated in this study appear to be very high, there arises the question as to why there is little progress in actual generation (in contrast to the numerous Memoranda of Understanding (MoU) and Letters of Intent (LoI) issued signifying interest in the Indian power sector)? Concerns for IPPs may include the following:

- Indian inexperience with such large private projects at the state level (as opposed to projects with multi-lateral agency funding),
- poor financial condition of the State Electricity Boards,
- political risks and regulatory delays.

The goals of any regulatory agency should be to keep the tariffs affordably low, while providing required rates of return for investors. In addition, newly growing economies will require smooth and rapid addition of generation capacity. In this context, it is important that utilities negotiate favorable deals with IPPs, as this process is unlikely to be a sprint but rather a long marathon. The CEA guidelines are officially a ceiling, and they state that nothing prevents utilities from entering into contracts with lower prices. However, in the absence of true competition, there has been little evidence that the prices are coming down.[25] It is likely that increased transparency in projects would reduce the time between techno-economic clearance and financial closure. Such a move might also minimize the opposition to these projects, reducing their riskiness.

[25] A small sample analysis of US IPPs shows considerable heterogeneity in electricity prices, much of which cannot be explained by input price variation (Comnes *et al*, 1996). The authors state that buyer willingness to pay is an important factor in determining prices.

References

Brealey, R A and Myers, S C (1996) *Principles of Corporate Finance* International Edition, McGraw-Hill, New York

Carstairs, J and Ehrhardt, D (1995) Financial structure in the Indian power sector *Energy Policy 23*(11), 981–990

Central Electricity Authority (1997) *Tariff Notification for Generating Companies* Central Electricity Authority, Govt. of India

Comnes, G A, Kahn, E P and Belden, T N (1996) The performance of the U.S. market for independent electricity generation *The Energy Journal 17*(3), 23–39

Dunkerley, J (1995) Financing the energy sector in developing countries *Energy Policy 23*(11), 955–965

EIA (1996a) *Annual Energy Outlook* 1997 Energy Information Administration, US Dept. of Energy

EIA (1996b) *Assumptions for the Annual Energy Outlook* 1997 Energy Information Administration, US Dept. of Energy

Ellerman, A D (1996) The competition between coal and gas *Resources Policy 22*(1/2), 33–42

EPRI (1993) *TAG Technical Assessment Guide 1993* Electric Power Research Institute

Federal Reserve (1997) *Federal Reserve Bulletin 83*(6)

Jones, C V (1991) *Financial Risk Analysis of Infrastructure Debt: The Case of Water and Power Investments* Quorum Books, Westport

Ministry of Finance (1996) *Economic Survey 1996–97* Govt. of India, Ministry of Finance, Economic Division

Ministry of Petroleum and Natural Gas (1995) Natural gas in India: strategies for development *Chemical Weekly 40*(39), 147–155

Ministry of Power (1994) *India's Electricity Sector — Widening Scope for Private Participation* Ministry of Power, Govt. of India

Ministry of Power (1997) *Presentation on Power Sector in India* Infrastructure Forum on Energy and Transportation, Washington, DC, U.S.–India Business Council

Morgan, M G and Henrion, M (1995) *Uncertainty — A Guide to Dealing with Uncertainty in Quantitative Risk and Policy Analysis* Cambridge University Press, Cambridge

NTPC (1996) *20th Annual Report 1995–96 NTPC* National Thermal Power Corporation (NTPC) Ltd.

Parikh, K S (1997) Fertiliser: evidence of goldplating *The Economic Times* 26 May, 1997, Mumbai

Parikh, K S (1996) *The Enron Story and Its Lessons* Indira Gandhi Institute of Development Research, Mumbai

RCG/Hagler Bailly Inc. and K&M Engineering and Consulting Corp. (1994) *IPPI Power Plant Cost Study— Compilation of "Hard" and "Soft" Costs for Power Plant Development in India* USAID

Roeder, T (1995) *Technologies for the Future Power Market* Presented at Shell International Petroleum Company Ltd. Workshop The Emerging Power Industry

Sant, G, Dixit, S and Wagle, S (1995) *The Enron controversy, Techno-Economic Analysis and Policy Implications* Prayas, Pune, India

U.S. Bureau of the Census (1996) *Statistical Abstract of the United States 1996 (116th Edition)* Washington, DC, US Dept. of Commerce

Venugopal, K (1997) *Personal Communication* Director, Financial and Commercial Appraisal, Central Electricity Authority, India