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Sri Lanka Electric Power Technology Assessment (SLEPTA)

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Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP)

Contents

Acknowledgement

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1

Introduction

Sri Lanka's power sector stands at a crossroad. Historically, the country has been almost entirely dependent upon hydro-electricity, and since independence has relied largely upon on a Government-owned, vertically integrated monopoly -- the Ceylon Electricity Board (CEB) -- to generate and deliver this power. Sri Lanka now confronts two fundamental issues.

The first concerns the choice of generating technology. With its hydro potential largely developed, a transition to thermal generation is inevitable. While renewable energy and demand side management have significant roles, neither is likely to be able to eliminate the need for fossil-based generation. Given significant increases in the load, the potential emerges for exploiting the scale economies inherent in larger thermal generation units. Yet these scale economies also give rise to a lock-in effect. If, for example, coal is chosen for the first new 300 MW baseload unit, it requires a commitment not just to that first unit, but to at least an additional two units. LNG is subject to even greater lock-in effects.

On the other hand oil-based units can be built in smaller increments, avoiding such lock-in effects. But they expose Sri Lanka to other risks, notably the volatility of price and susceptibility to geopolitical supply disruption.[1] The environmental trade-offs may also be difficult to resolve: while oil avoids the particulate and solid waste pollution from coal, the cheapest heavy fuel oil has three to four times the uncontrolled sulfur emissions of a coal plant. At the same time, LNG -- certainly the most attractive option from an environmental point of view – appears to be the most expensive.

The second major issue concerns the institutional arrangements. The Government has already indicated its desire for reform and restructuring of the power sector in an effort to mobilise private capital. But the transition from concessionary to private financing has profound implications for the cost of power. Private financing offers made so far appear to be significantly more expensive than the concessionary financing that has

[1] At the time of the 1973 oil crisis, while the country as a whole was seriously affected, Sri Lanka's power sector was little affected because at that time its dependence on oil was minimal. But that has changed: in 2000, a normal hydro year that saw relatively few power cuts, 48% of electricity generation was from oil. Sri Lanka's vulnerability to any future oil supply disruptions will be severe in all energy sectors.

been available in the past. At the same time, very different institutional structures are implied by these two financing modalities.

The Government (and in particular the Ceylon Electricity Board) has requested assistance from the World Bank in providing an economic and financial analysis of technology and fuel options. Therefore, this study is focused mainly upon the first set of issues. The objective of the study is to review the technology and fuel choices available to Sri Lanka, and document the economic and financial aspects of these options to a similar level of detail, in order that decision-makers may judge for themselves the advantages and disadvantages of each.

Much of the material presented here is documented fully in a Background Report, to which the reader is referred for more detail.[2] The more important sections of the Background Study are included here as Annexes.

1.1 Critical assumptions

Environmental costs**:** This report focuses mainly on the economic and financial costs of different generating options. A full trade-off analysis between economic and environmental attributes of policy options, including those in the transportation sector, and including consideration of air emission damage costs, is reported elsewhere.[3]

The present study includes the costs of environmental compliance in the capital and operating costs of each option. Thus, for example, in the case of oil-steam plants, whose unconstrained emissions using the cheapest imported heavy fuel oil (with 3.5% sulfur by weight) do not meet proposed sulfur emission standards, we add the costs of either fitting such plants with flue gas desulfurisation (FGD), or of blending fuel oil with more expensive low-sulfur fuel oils to a level which assures compliance with environmental standards. The capital costs of coal plants similarly include the cost of electrostatic precipitators (ESPs) necessary to meet particulate standards.

The cost of capital**:** The conventional practice in economic analysis is to price projects funded in the public sector at the real social discount rate (SDR) which is taken here at 10%. This is also the rate used by CEB in its recent generation planning studies, as well as by CEB's consultants for cost benefit analysis in detailed feasibility studies. Selected sensitivity analyses are provided for alternative values of 8%, 12% and 14%.

However, in the case of privately financed projects, particularly foreign-financed IPPs, the actual cost of capital may be significantly different. For example, the weighted cost of foreign capital for the 250 MW oil-fired project proposed by ECNZ in 1999 was 21%! However, in others (such as the AES project), the apparent weighted cost of capital is fairly close to 10%.

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2 International Development and Energy Associates, *Sri Lanka Electric Power Technology Assessment (SLEPTA): Background Report,* April 2000.

3 P. Meier and M. Munasinghe, *Environmentally Sustainable Energy Development in Sri Lanka: Impacts, Issues and Policy Options*, World Bank, 2002. Environmental valuation techniques are explained in M. Munasinghe, *Environmental Economics and Sustainable Development,* 1992.

1.2 Limitations

This report has several limitations, mostly a consequence of limitations of time and resources:

- For some technologies, we have only reviewed such information as is immediately available in the public domain, or data which project proponents have chosen to make available to CEB. For example, in the case of the ENRON LNG project in Puerto Rico (which has been held up as an example of a small scale LNG development), the available information is quite limited.
- The only environmental impact that is monetised is the potential value of carbon offsets. However, on the basis of the best current estimates, this value is likely to significantly exceed the monetised value of other air emissions. Moreover, as noted, for other pollutant emissions, the costs of environmental compliance (such as FGD in the case of oil-steam burning high sulfur fueloil) have been included.
- While sensitivity analyses are provided as appropriate, time and resources did not allow a full risk analysis.
- We have not conducted an independent audit of the information provided to us. For example, the financial costs of diesel fuel to various IPPs and CEB were taken as given to us by the Ceylon Petroleum Corporation

1.3 Options evaluated

The following technology-fuel options were evaluated

- Steam cycle plants: coal and imported heavy fuel oil
- Diesels: residual oil, imported heavy fuel oil, diesel oil
- Combustion turbines (combined and simple cycle): diesel oil, naphtha, LNG
- Hydro conventional and mini-hydro
- Renewables: wind, dendro-thermal

A preliminary screening identified a number of technology and fuel options that are not likely to be viable in Sri Lanka. Therefore, these technologies were not examined in great detail. A first group (listed below) represent technologies that have been advocated for Sri Lanka, but which may be eliminated from consideration during the next decade, since they are quite far from the stage of being commercially proven or are economically unviable.

- Wave and tidal energy
- OTEC
- Solar thermal (solar chimneys, etc.).

- Many of the so-called "clean coal" technologies, including in particular integrated gasification-combined cycle (IGCC) and pressurised fluidized bed combustion (combined cycle) PFBC.

This is not to say that they do not have long term potential, or that they are not appropriate as subjects of research. However, it does mean that these options are not candidates for the short to medium term, and progress in any one of these technologies is unlikely to affect the decisions that must be taken over the next few years. In the case of IGCC and PFBC, neither can yet be viewed as commercially available. PFBC is presently offered by only a single vendor, and has been applied elsewhere only in developed countries in situations of extraordinary ambient air quality requirements.

A second category of technologies may be deemed to be technologically proven and commercially available, but their advantage is limited to circumstances that simply do not apply to Sri Lanka. These include

- AFBC (atmospheric fluidised bed combustion), that is of interest primarily where a country has large domestic resources of poor quality solid fuel (such as India and China).
- Nuclear: that may be excluded on grounds of cost and unit size.
- LPG: that may be excluded for large plants on grounds of high fuel cost, and for small plants on grounds of cost and limitations of import infrastructure.

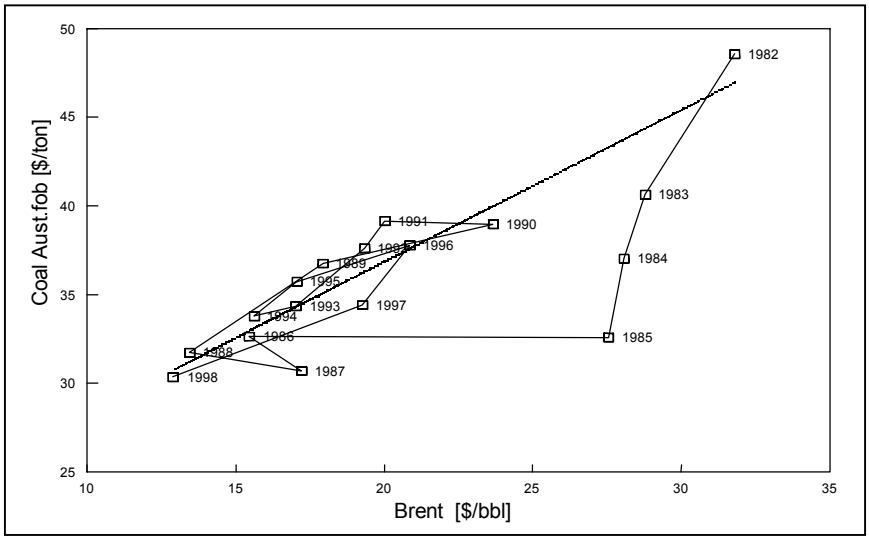
However, since clean coal technologies have been examined in detail in some past studies of Sri Lanka, an analysis of AFBC is provided for comparison of costs and emissions of other baseload options.

1.4 Structure of study

The first step was to develop a set of consistent fuel price projections related to marker crude-oil prices. It was observed that many past studies suffered from inconsistencies, and economic prices were not properly defined. For example, Figure 1.1 shows the historical relationship between Brent and Australian export coal, which suggests that long-term average coal prices are much more sensitive to world oil prices than has been assumed in past studies of generating options in Sri Lanka.[4] Petroleum product prices (Gulf and Singapore) were then linked to marker crude prices using similar statistical relationships, and adjusted for freight to Sri Lanka. A sensitivity analysis was conducted for selected fuels to test the impact of future deviations from the historical patterns. The details of the methodology to ensure consistency in fuel price projections are provided in Section 2 of the Background Study.

[4] For example, in CEB's 1999 generation plan, the sensitivity analysis assumes a change in oil price, keeping the coal price constant. This is a case of interest, but the more probable situation is that the coal price would also change, suggesting that the most useful sensitivity analysis is to run a range of world oil prices --say from $13/bbl (reflecting the low 1998 average) to $25/bbl (reflecting the December 1999 price) -- with corresponding adjustments in both coal and petroleum product prices.

Figure 1.1: Historical relationship between Brent and Australian prices (annual averages)



Next, one-on-one comparisons of technologies were evaluated using a screening curve analysis that evaluated unit cost/kWh and lifetime cost (as NPVs) as a function of assumed plant load factors. Given the uncertainty of capital cost estimates, a sensitivity analysis was conducted to identify switching values. The assumptions for each technology (capital costs, heat rates, operating costs, etc.,) were discussed in detail, again with a view to resolving inconsistencies in the assumptions of previous studies. This analysis was conducted in terms of economic prices.

At the express request of CEB, two options were analysed in particular detail, namely oil-fired steam cycle plants and LNG (for which ENRON has made a proposal to CEB) – the results of which are presented here. A 1998/1999 proposal by the Electricity Corporation of New Zealand for the Marsden B oil-fired plant is presented in Annex V of the Background Report.

We then considered the impact of assumptions about the financing package. These prove to have a far greater impact on the results than the distortions imposed by fuel taxes and excise duties on equipment.

All of the options were then offered as candidates in a power systems planning study. Model runs were conducted in terms of financial as well as economic prices, and the results compared to the simple one-on-one screening curve analyses. We also compare the results of our studies with those of the latest CEB Generation Expansion Plan.

2

Economic Analysis

2.1 Screening curve analysis

Simple one-on-one comparisons of different technologies were undertaken using a screening curve model that assessed cost/kWh and lifetime NPV as a function of annual plant factor. Although most assumptions were based on the 1998 CEB generation plan and project feasibility studies prepared by CEB's consultants, these have been modified as necessary in the case of inconsistencies and other anomalies.[5]

Table 2.1 lists the assumptions for the one-on-one comparisons based on an $18.5/bbl Saudi Light price (about 20.4$/bbl for Brent). It is assumed that oil-steam uses imported fuel oil blended to 1.6% sulfur.[6] The indicated capital costs are adjusted for opportunity cost of capital and the infrastructure penalty.[7]

Coal is seen to be least cost for baseload duty, combined cycle for cycling duty (PLF 15-40%), and open cycle combustion turbines for thermal peaking (Figure 2.1). However, the advantage of coal over oil-steam is small, and in the range of 40-50% PLF the costs are essentially identical. Indeed, when the analysis is repeated for the lower oil price of $16/bbl (Figure 2.2), the differences between coal and oil-steam are smaller still.

The differences between technologies are further illuminated by looking at the lifetime cost differences between coal and the other alternatives for some constant PLF -- as shown in Table 2.2. The lifetime NPV advantage to coal is in the range of $8-37million when oil prices are in the range of 16 to 18.5 $/bbl; in the present trading range of 20-25$/bbl, the advantage to coal is greater still.

Table 2.1: Input assumptions

[5] Some of the more important issues concern assumptions for capital and non-fuel operating costs for oil steam-cycle plants. See Annex I for details.

[6] This is the assumption used by ECNZ in their proposal for a 250 MW oil steam-cycle plant . However, if the emissions standards as proposed by the Central Environment Authority are actually implemented, the sulphur content of heavy fuel oil would need to be reduced to around 1.1%S.

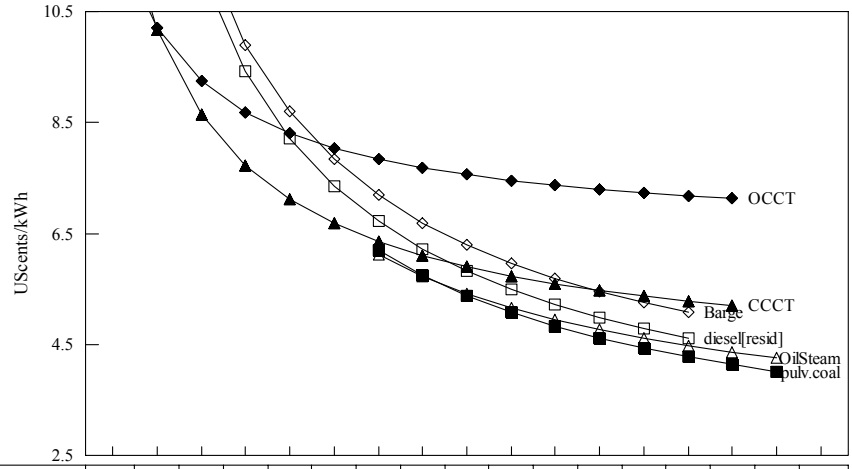
[7] For example, the overnight capital cost of coal is taken as $1,008/kW (as per Electrowatt-- see Annex Table A1.5). This is adjusted to 1999 prices to yield $1,071/kW. This is adjusted by 7% for the up-front-infrastructure penalty of 7% (see Box 1 in Annex I) to yield $1,146/kW. Finally this is adjusted for the opportunity cost of capital to $1,303.

		pulv. coal	*OCCT*	*CCCT*	*diesel [resid]*	*diesel [barge]*	*Oil Steam*
input data							
total capacity	[MW]	300	105	300	150	300	300
capital cost	[$/kW]	1303	386	725	1332	1334	1063
life	[years]	30	20	30	25	25	25
fixed O&M	[$/kW/month]	0.56	0.36	0.28	0.92	0.92	0.48
variable O&M	[mills/kWh]	2.79	2.85	2.72	7.36	7.36	2.37
scheduled maintenance	[days]	40	30	30	30	30	30
forced outage rate	[ ]	0.03	0.08	0.08	0.15	0.15	0.06
heat rate, net	[KCal/kWh]	2293	3060	1890	1954	1954	2293
primary fuel		coal	auto diesel	auto diesel	resid	Furnace oil	imp. fuel oil
heat content	[KCal/kg]	6300	10550	10550	10300	10300	10300
fuel price, cif plantgate	[$/bbl]	0	28.1	28.1	11.6	15.3	15.8
	[$/ton]	49	212	212	78	103	106
	[$/mmBTU]	1.96	5.05	5.05	1.91	2.51	2.6
	[cents/GCal]	779	2006		756	997	1031
fixed charge factor	[ ]	0.11	0.12	0.11	0.11	0.11	0.11
annual capital cost	[$/kW/year]	138.2	45.3	76.9	146.7	147	117.1
fixed O&M/year	[$/kW/year]	6.7	4.3	3.4	11	11	5.7
total fixed cost	[$/kW/year]	145	49.6	80.2	157.8	158	122.9
fuel cost	[UScents/kWh]	1.79	6.14	3.79	1.48	1.95	2.36
variable O&M	[UScents/kWh]	0.28	0.29	0.27	0.74	0.74	0.24

Table 2.2: Lifetime cost difference $US million (NPV at 10% over 30 years) for baseload duty at 75% PLF

	$16/bbl		*18.5$/bbl*	
	NPV	*(coal)*	*NPV*	*(coal)*
coal	776		794	
CCCT	886	110	982	188
diesel (residual)	821	45	857	64
diesel (furnace oil)	909	133	946	152
oil-steam	784	8	831	37

Figure 2.1: Screening curve (Arab Light 34 $18.5/bbl)

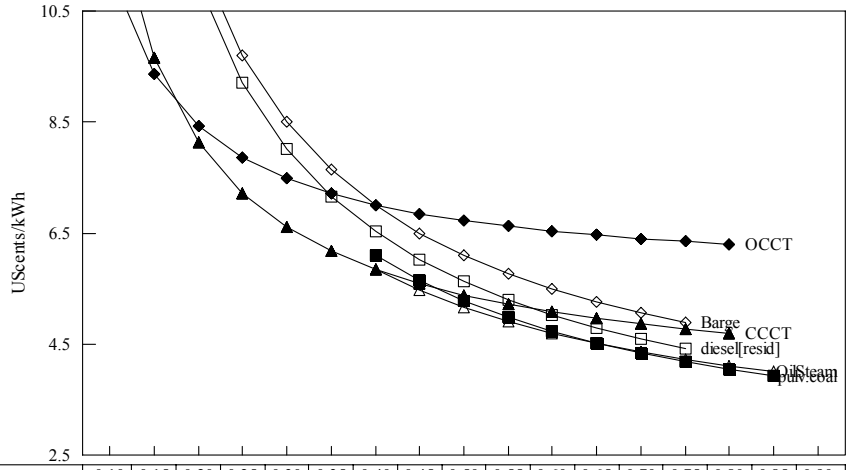


annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ OCCT	12.09	10.20	9.26	8.69	8.31	8.04	7.84	7.68	7.56	7.45	7.37	7.29	7.23	7.18	7.13		
▲ CCCT	13.22	10.17	8.64	7.73	7.12	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
⊟ diesel[resid]	20.22	14.22	11.22	9.42	8.22	7.36	6.72	6.22	5.82	5.49	5.22	4.98	4.79	4.61			
◇ Barge	20.72	14.71	11.70	9.90	8.70	7.84	7.19	6.69	6.29	5.96	5.69	5.46	5.26	5.09			
△ OilSteam							6.11	5.72	5.41	5.15	4.94	4.76	4.61	4.47	4.36	4.25	

Table 2.3: Capital cost switching values

	baseline estimate, $/kW	*switching value $/kW*	*reduction in baseline to attain switching value*
Coal	1303		
CCCT	725	98	86.5%
diesel (residual)	1332	1127	15.4%
diesel (furnace oil)	1334	846	36.6%
oil-steam	1063	944	11.3%

Figure 2.2: Screening curves for $16/bbl (Arab Light)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.11	5.65	5.28	4.98	4.73	4.52	4.33	4.18	4.04	3.92	
◆ OCCT	11.26	9.37	8.42	7.86	7.48	7.21	7.01	6.85	6.72	6.62	6.53	6.46	6.40	6.35	6.30		
▲ CCCT	12.71	9.66	8.13	7.21	6.60	6.17	5.84	5.58	5.38	5.21	5.08	4.96	4.86	4.77	4.69		
⊟ diesel[resid]	20.02	14.02	11.02	9.22	8.02	7.16	6.52	6.02	5.62	5.29	5.02	4.79	4.59	4.42			
◇ Barge	20.53	14.51	11.51	9.70	8.50	7.64	7.00	6.50	6.09	5.77	5.49	5.26	5.06	4.89			
△ OilSteam							5.85	5.46	5.15	4.90	4.68	4.51	4.35	4.22	4.10	4.00	

Clearly the most problematic assumptions are for capital costs. The basis is relatively firm in cases where recent capital costs have been revealed in international competitive bidding in Sri Lanka (such as for open cycle combustion turbines, or auto-diesel-fueled combined cycle plants). In other cases (such as for oil steam cycle plants or LNG, discussed below), such cost estimates are subject to high uncertainty. Therefore our approach is to start with the coal plant (for which extensive site-specific costing studies have been conducted by CEB's consultants), and then assess the credibility of the other estimates through a comparative switching values analysis.

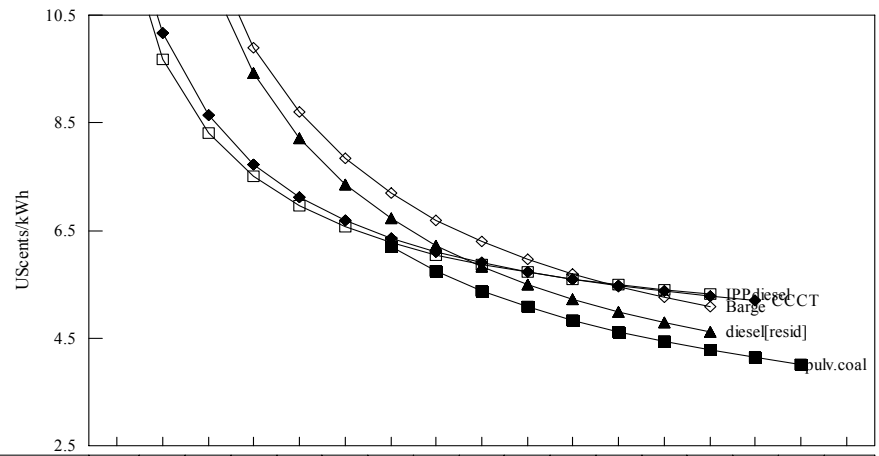
For example, if the switching value of an alternative to coal requires a more than 86% decrease in capital cost (relative to the baseline) in order to be competitive - as in the case of auto-diesel fired combined cycle for baseload duty -- one may be reasonably sure that coal is least cost (other things equal). However, if such an alternative requires only a 11% decrease (as in the case of oil-cycle steam), then the assumptions for that option require further scrutiny. These switching values are shown in Table 2.3. At the switching value, the life-cycle costs and unit electricity price of the selected alternative are the same as for coal.

2.2 Small diesels

The 22.5 MW Lakdanavi and the two recently signed 20 MW “medium term” 10-year BOO projects at Anuradhapura and Matara, running on furnace oil, have been implemented as IPPs. Unlike diesels using residual fuels (such as those at Sapugaskanda), such units have significantly lower capital costs -- but correspondingly higher fuel costs.

Figure 2.3 shows the screening curve for small diesels (compared to options suited to intermediate and baseload), in which we assume a capital cost of $600/kW. It is evident that at such capital costs, plants are uneconomic for baseload operation, but are similar to CCCTs for load factors of less than 40%.

Figure 2.3: Screening curves for small diesels (10% discount rate; 18.5$/bbl Arab Light price)

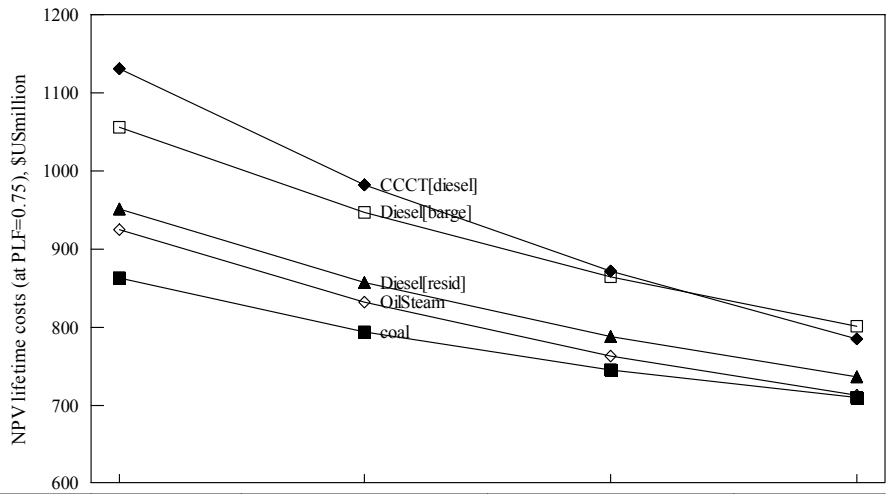


annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ CCCT	13.22	10.17	8.64	7.73	7.12	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ diesel[resid]	20.22	14.22	11.22	9.42	8.22	7.36	6.72	6.22	5.82	5.49	5.22	4.98	4.79	4.61			
⊟ IPPdiesel	12.41	9.68	8.32	7.50	6.96	6.57	6.28	6.05	5.87	5.72	5.59	5.49	5.40	5.32			
◇ Barge	20.72	14.71	11.70	9.90	8.70	7.84	7.19	6.69	6.29	5.96	5.69	5.46	5.26	5.09			
△																	

2.3 Impact of the discount rate

The above analysis uses a 10% discount rate to reflect the opportunity cost of capital. Since generation technologies vary in capital intensity, the results may be sensitive to the rate assumed. In Figure 2.4 we show the lifetime costs at a typical value of plant load factor (PLF = 0.75), for a range of discount rates from 8 to 14%. Technology rankings are unchanged in the 8-12% range, but at 14% CCCT using auto-diesel is cheaper than diesel (using furnace oil). However, at 14%, the advantage of coal over oil-steam is very small indeed.

Figure 2.4: Sensitivity to discount rate: lifetime NPVs (at 75% PLF) in $US million



discount rate	0.08	0.10	0.12	0.14
■ coal	862	794	745	710
◆ CCCT[diesel]	1130	982	871	785
▲ Diesel[resid]	950	857	788	736
⊟ Diesel[barge]	1055	946	864	801
◇ OilSteam	925	831	763	713

(World oil price: 18.5$/bbl for Arab Light)

2.4 The impact of delay

In terms of NPV of lifetime costs, the differences between some technologies (e.g. between coal and oil steam-cycle plants for equivalent baseload duty, a range of $8 - 37 million) are seen to be relatively small. Equally important, these differences are also relatively small compared to the cost of delay. Suppose, for example, a one-year delay in making a commitment to a 300 MW baseload plant, and that the power lost (1,971 GWh assuming 75% PLF) has to be generated in thermal peaking units. Suppose further that the alternative generation capacity has a shorter gestation time, and could be advanced from its least cost commissioning date by one year. Then the impact of delay is the difference in fuel cost between generating this 1,971 GWh in the coal plant, versus having to generate this power with diesel oil in either OCCT or CCCT plants, *less* the saving attributable to deferring the capital costs of the coal plant by one year, *plus* the cost of advancing the alternative plant by one year.[8] As indicated in Table 2.4, the penalty for this delay is in the range of $24-$60 million (in NPV terms).

[8] The difference between an outlay of λ, n years hence, to an outlay of λ today, is $\lambda-\lambda/(1+r)^n$ where r is the discount rate.

Table 2.4: Impact of a one-year delay

		pulv. coal	*OCCT*	*CCCT*
capital cost	[$US million]	411	116	217
capacity	[MW]	300	300	300
PLF	[ ]	0.75	0.75	0.75
replacement generation	[GWh/year]	1971	1971	1971
fuel cost	[UScents/kWh]	1.79	6.14	3.79
annual fuel cost	[$US million]	35.2	121	74.7
delta(coal)	[$US million]		85.8	39.5
capital cost impacts				
delay coal by 1 year	[$US million]		-35.5	-35.5
advance alternative by 1 year	[$US million]		10.5	19.8
total impact	[$US million]		60.7	23.7

However, this assumes that the adjustment required is to advance the alternative by one year. If that alternative (with shorter gestation time) must be advanced by more than one year (relative to the least-cost expansion plan), then the impact is correspondingly greater. For example, if the advance time is 3 years, the total impact of delay rises to $58-79 million,[9] significantly above the difference between lifetime NPVs of coal and oil-steam ($8-37 million).

Nevertheless, this is not true of *all* technology comparisons. The lifetime cost difference between an auto-diesel fueled CCCT and a steam-cycle plant lies in the range of $110-188 million -- which is well above the cost of a one to two-year delay.

Several conclusions may be drawn at this point

1. The most significant uncertainty in this analysis is capital cost. In the present highly competitive international power generation equipment market, capital costs for all power generation plant have fallen dramatically over the past few years (though particularly for combustion turbines). Nevertheless, the switching values analysis for capital costs shows that for baseload duty, only oil-steam running on heavy fuel oil, or diesel using residual oil, are in the competitive range with coal. Since additional quantities of residual oil from the Sapugaskanda refinery would only be available if the refinery were expanded, large scale use of such diesels is not feasible for the time being. Therefore we may say that

[9] If, at worst, adjustment of the construction schedule is not possible, and the output is lost (as for example occurred in 1996 during the drought, when as a consequence of delays in decisions there was inadequate thermal capacity in the system), then if the value of unserved energy is 10 cents/kWh, the value of the lost output rises $197 million. The cost of the 1996 power crisis has been attributed largely to the failure to implement the thermal capacity additions called for by the expansion plans of the early 1990s (see Lanka International Forum on Sustainable Development, *Linkages between Economic Policies and the Environment in Sri Lanka*, December 1998). This report estimated the economic costs of the power crisis at around $73 million (including $50 million spent on emergency generator sets, and $23 million in loss of manufacturing GDP).

- For baseload duty, the steam cycle - - be it oil or coal -- is least-cost. This is not unexpected given that Sri Lanka does not benefit from low cost domestic gas (which often changes the economics in favor of combined cycle plants even for baseload).
- For cycling duty with load factors in the 20-50% range, combined cycle plants using auto-diesel (or naphtha) are least-cost.
- For thermal peaking, open cycle combustion turbines using auto-diesel are least cost.

2. Clearly oil-cycle steam plants, as an alternative to coal, merit more detailed analysis (presented below). However, the differences are likely to be small, and do not justify any delay in making a commitment to the needed additional baseload capacity.
3. It has been the practice of CEB (and its consultants Electrowatt) to compare the coal plant against an auto-diesel fueled CCCT to justify the former in economic analysis: the CCCT is claimed to be the "next best" option. This assumption is unjustified. Our results show that the second best option for baseload is steam-cycle oil.
4. As discussed at some length in the Background Report (and Annex I), we note a number of inconsistencies in assumptions in the various studies conducted to date, although it does not appear that this has resulted in conclusions that are substantively different to those obtained by us in this report. Nevertheless, we recommend that future analyses adopt these more consistent assumptions.

2.5 Steam cycle oil

Switching values for capital costs of oil steam-cycle plants will be dependent upon a variety of assumptions including the world oil price, the discount rate, and assumptions about the sulfur content of the fuel necessary to meet ambient SOx standards. Table 2.5 shows the capital cost switching values for a broad range of oil prices from 10-13$/bbl (that reflects the 1998 low, and average 1998 conditions) to $21/bbl (that reflects current conditions). The assumption here is that fuel oil will be blended to meet the proposed sulfur emission standard (520 mg/MJ).

Table 2.5: Switching values for steam-cycle oil plants

		oil plant capital cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
Baseline estimates			
Coal	1303		
oil cycle steam	1063		
Switching values for oil-cycle steam at:			
10$/bbl	1245	17%	0.96
13$/bbl	1126	6%	0.86
16$/bbl	1007	-5%	0.77
18.5$/bbl	908	-15%	0.7
21$/bbl	809	-24%	0.62

Oil price is for Arab Light; fueloil blended to 1.1% sulfur.

This shows, for example, that at 16$/bbl, the capital cost would need to fall by 5% of the baseline estimate for the lifetime costs to be equal. Moreover, at this value ($1007/kW) the capital cost of oil plant would need to decline to 77% that of the coal plant.

Alternatively we may examine the lifecycle costs (Table 2.6), which show that the economic consequence of choosing *oil* rather than coal is a *benefit* of $20 million if the (Arab light) oil price (averaged over the lifetime of the plant) is $13/bbl, but a *loss* of $79 million if the oil price (average) is 21$/bbl. Based on the consensus forecasts for a probable average oil price over the next decade of 15-20$/bbl, coal is seen to have an advantage (if the capital cost of the plant is at the Electrowatt estimate). Note, however, that if the capital cost falls to the switching value (say $908 at 18.5$/bbl, see Table 2.5), then the lifetime costs are the same. The NPV of the coal plant also increases with increases in the oil price, because long-term coal prices are linked to long term changes in the world oil price (as illustrated in Figure 1.1).

Table 2.6: Switching Life-cycle costs, NPV ($US million)

Oil price, $/bbl	*coal*	*oil*	*consequences of the choice of oil*
10	734	677	57
13	755	735	20
16	776	794	-18
18.5	794	842	-48
21	811	891	-79

10% discount rate; 75% PLF; Oil prices for Arab Light

These results assume that fuel-oil blended to 1.12% sulfur would be used, such

that the proposed emission standard for SOx from oil plants (520 mg/MJ) could be met. However, whether emissions at this level would also satisfy the ambient air quality standard is unclear. In the case of the proposed coal plant, whose emissions are between 340-542 mg/MJ, depending on assumptions, the Environmental Impact Assessment shows that FGD is not required to meet ambient standards (proposed at 520mg/MJ for coal plants larger than 73MW) when low-sulfur coal is used.[10] In order to be sure of compliance, an oil plant may need to have SOx emissions that are no higher than those of the corresponding coal plant. This would again require either an FGD system, or the use of a fueloil blended to 0.8% S. The detailed analysis provided in Chapter 5 of the Background Report suggests that blending is more cost-effective than FGD, so we assume here the blended fuel option.

The corresponding switching values for this worst case for heavy oil are indicated in Table 2.7. For 18.5$/bbl, the switching value falls from 908$/kW to 886$/kW -- in other words, if more expensive lower sulfur oil must be used, the capital cost will need to fall further to remain competitive with coal. Nevertheless, capital costs in the range of 887-988$/kW (for $16-18.5/bbl) imply that these are between 76 to 68% of the capital cost of coal -- which seem only slightly lower than values assumed elsewhere (such as the 75% used in the recent World Bank study of generating options in the Philippines).

Table 2.7: Capital cost switching values for steam oil cycle plants, fueloil blended to 0.8 %S

		oil plant capital cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
baseline estimates			
coal	1303		
oil cycle steam	1063		
switching values for oil-cycle steam at:			
10$/bbl	1232	16%	0.95
13$/bbl	1110	4%	0.85
16$/bbl	988	-7%	0.76
18.5$/bbl	886	-17%	0.68
21$/bbl	785	-26%	0.6

The corresponding life-cycle impacts are shown in Table 2.8. The costs of choosing oil (in the 16-18.5$/bbl range), rather than coal, increase from $18 - 48 million (Table 2.6) to $24-55 million.

[10] The Environmental impact statement also looks at a "worst case" coal of 0.7%S and lower heat content of 6,050 KCal/kg: this just meets the proposed standard.

Table 2.8: Lifecycle costs, NPV ($US million)

oil price, $/bbl	*coal*	*oil*	*consequences of the choice of oil*
10	734	681	53
13	755	740	15
16	776	800	-24
18.5	794	849	-55
21	811	898	-87

10% discount rate; 75% PLF; Oil prices for Arab Light

These results are for a discount rate of 10%. But since oil plant is less capital-intensive than coal, it follows that higher discount rates would favor oil. Indeed, the weighted cost of capital in IPPs is likely to be higher than the 10% that may be appropriate for public sector projects. Moreover, in an IPP financing, soft costs (financing and legal fees, development fees, IDC, etc.) add at least 25% to the baseline cost - which will therefore again be higher for coal than for oil. Thus, in Table 2.8, we show the corresponding results for 12% discount rate. As expected, the switching values of capital cost are closer to those of coal than those previously indicated in Table 2.5: for example, at $18.5/bbl, the capital cost of the oil plant would need to be only 79% of the coal plant cost, as opposed to 70% at 10% discount rate (Table 2.5).

Table 2.9: Life Capital cost switching values for steam oil cycle plants, with fueloil blended to 1.1%S and 12% discount rate cycle

		oil plant capital cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
baseline estimates			
coal	1671		
oil cycle steam	1363		
switching values for oil-cycle steam at:			
10$/bbl	1618	19%	0.97
13$/bbl	1516	11%	0.91
16$/bbl	1413	4%	0.85
18.5$/bbl	1327	-3%	0.79
21$/bbl	1241	-9%	0.74

Baseline estimate for coal=$1303/kW x 1.25 soft-cost multiplier for IPPs;
for oil=$1063/kW x 1.25=$1329/kW.

The lifecycle costs (Table 2.10) -- assuming the 1,363 $/kW capital cost -- now show a benefit of $15 million at $16/bbl, versus a *cost* of $11million at $18.5/bbl.

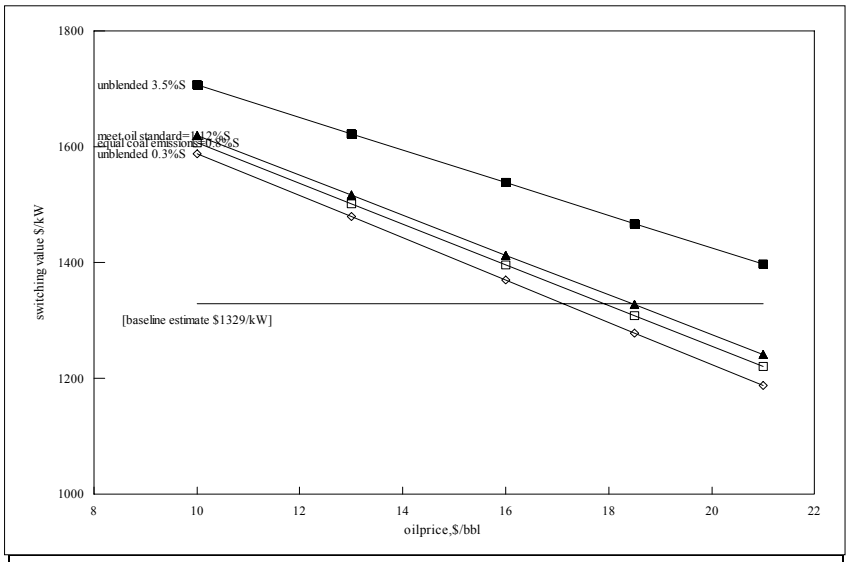
Table 2.10: Lifecycle costs, NPV ($US million), 1.1% S

	coal	*oil*	*consequences of the choice of oil*
10$/bbl	794	716	79
13$/bbl	812	765	47
16$/bbl	830	815	15
18.5$/bbl	845	857	-11
21$/bbl	860	898	-38

12% discount rate; 75% PLF; Oil prices for Arab Light

The complete sensitivity for switching values as a function of both oil price *and* sulfur content is shown in Figure 2.5. This figure is to be interpreted as follows: for any capital cost that is lower than the curve (for a given level of sulfur), oil will be cheaper than coal. For example, at $16/bbl, and 3.5%Sulfur oil, the switching value is $1,538/kW (as opposed to the baseline cost of 1,363$/kW); this means that any capital cost lower than $1,538/kW makes oil cheaper. Table 2.11 shows the corresponding life-cycle costs (for the baseline oil plant capital cost).

Figure 2.5: Sensitivity analysis for oil capital cost switching values ($/kW)



	oil price (Arab Light), $/bbl				
	10	13	16	18.5	21
unblended fuel 3.50%S	1707	1622	**1538**	1467	1397
blended to meet oil standard (340 mg/MJ)=1.1%S	1618	1516	1413	1327	1241
blended to meet same emissions as coal plant (171 mg/MJ)=0.8%S	1607	1501	1396	1308	1220
unblended fuel 0.30% S	1588	1479	1370	1279	1188

assumptions: 12% discount rate, 75%PLF

Table 2.11: Benefits of oil steam-cycle versus coal, $US million at baseline estimate of $1,363/kW

	oil price (Arab Light), $/bbl				
	10	*13*	*16*	*18.5*	*21*
unblended fuel 3.50%S	106	80	54	32	10
blended to meet coal standard (520 mg/MJ)=2.49%S					
blended to meet oil standard (340 mg/MJ)=1.63%S	79	47	15	-11	-38
blended to meet same emissions as coal plant (171 mg/MJ)=0.82%S	75	43	10	-17	-44
Unblended fuel 0.30%S	69	36	2	-26	-54

But now suppose that the ratio of oil to coal capital cost is not 80%, but 75% (the assumption of the Philippines study) -- with a baseline oil capital cost estimate of $1,253. Then the benefits (and costs) of oil work out as indicated in Table 2.11. Under such assumptions, if the presently proposed sulfur standard for oil is to be met, oil is cheaper at any cost lower than about 19.5$/bbl (and brings a benefit of $23million even if the Arab light oil price is at $18.5/bbl (Brent at around $20/bbl).

Table 2.12: Benefits of oil steam-cycle versus coal, $US million at baseline estimate of $1,253/kW

	oil price (Arab Light), $/bbl				
	10	*13*	*16*	*18.5*	*21*
unblended fuel 3.50%S	140	114	88	66	44
blended to meet oil standard (340 mg/MJ)=1.63%S	113	81	49	23	-4
blended to meet same emissions as coal plant (171 mg/MJ)=0.82%S	109	76	44	17	-10
unblended fuel 0.30%S	103	70	36	8	-20

12% discount rate, 75%PLF

2.6 Conclusions concerning oil vs. coal steam cycle

These results permit several important conclusions

- Whether imported heavy fuel-oil or coal steam cycle is least cost depends critically upon assumptions. Small changes in assumptions may switch the least-cost choice.
- Thus it cannot be ruled out that in a competitive bid in which the choice of fuel/technology were left to the bidder, that coal would necessarily win -- though it would appear somewhat unlikely if the fuel price risk is assigned to the seller. Nevertheless, there may be scope for optimisation and hedging techniques that would be within the competence and experience of an international IPP, which may make oil more attractive to a private owner.

- In the foreseeable future, a return to oil prices in the 10-15$/bbl is most unlikely. At current oil prices (on the 20-25$/bbl) we may conclude with high confidence that coal will be the least-cost choice.
- If the fuel price risk is taken by the buyer, then comparison of bids across different fuels and technologies would involve a risk evaluation, in which the higher fuel price risk associated with oil needs to be traded-off, quantitatively (and transparently) against the lower capital cost. Such a risk assessment (and related questions of benefit sharing, structuring and quantifying the corresponding criteria for evaluation of proposals, etc.) falls outside the scope of the present study, but should certainly be undertaken before one could consider an RFP that leaves technology and fuel choice to the IPP.
- The results suggest that duel-fuel capability may be advantageous - since when oil prices are low (as they were for much of 1998), a dual-fuel capable plant would almost certainly use heavy fuel oil rather than coal.
- The concept of multi-fuel capable plants also merits some further examination, particularly since the GHG overlay study suggests co-firing of wood (at a low volume ratio) from dendro-thermal plantations as one of the potentially more attractive GHG mitigation measures).

2.7 The impact of infrastructure front loading

One of the contentious issues in the public debate over new generation plants has been the practice of averaging up-front infrastructure costs over all the units of a multi-unit plant in economic analyses. This has been done both by CEB in its generation planning studies, as well as by international consultants in their detailed feasibility studies (such as Tokyo Electric Power for the Kerawalapitiya project, or Electrowatt for the West Coast Coal project). The issue is potentially significant, for the differences between the first and subsequent units is sometime large. Critics claim that this has biased past studies in favor of coal (which have particularly high up-front costs). For example, the first unit cost for coal is $1,451/kW, the average $1,008/kW, and Units 2&3 $787/kW (see Table 2.13).

By looking at lifetime NPVs and comparisons of levelised costs (detailed analysis is provided in Annex II of the Background Report) we find that use of the average value -- in either system planning models or simple one-on-one comparisons -- results in an effective understatement of project capital costs of about 7% (in the case of the coal project, with the second and third units commissioned 3 and 7 years after Unit 1). Clearly use of the first unit costs as a basis for decisions would give an equally biased picture, since subsequent units have substantially *lower* costs.

Table 2.13: Capital costs of the coal plant

	Unit 1 at actual	*Unit 1 at average*	*Units 2&3 at actual*
outdoor site works	38.1	17.16	6.7
buildings and structure	32.9	26.29	23.01
steam generation plant	82.4	80.47	79.5
turbine generator plant	60.0	58.57	57.86
fuel and ash handling	25.5	12.17	5.5
balance of plant	32.7	20.05	13.75
Switchyard equipment:	19	15.45	13.7
Control & instrumentation	6.2	5.59	5.3
Resettlement costs, Environment monitoring	1.5	0.5	0
Subtotal 1	298.2	236.3	205.3
Contingencies	14.9	11.82	10.28
Engineering & supervision	14.9	11.82	10.28
Subtotal 2	328	259.9	225.85
coal unloading	65.29	21.55	
Transmission	41.91	20.96	10.49
Total	435.17	302.4	236.01
$/Kw	1451	1008	787

Source: Detailed Feasibility and Economic Analysis Studies by Electrowatt

However, increasing capital costs by 7% has little impact on the results – we find that coal is still least cost for baseload requirements. Nevertheless, we recommend that in future WASP generation planning studies undertaken by CEB, such an adjustment is made.

To be sure, if *only* the first unit at a multi-unit plant is built, then its effective capital costs are effectively 40% higher than the assumed average. However, it is very unlikely that Units 2 and 3 would not be required. More specifically, there are only three circumstances under which the project would conceivably be abandoned after the first unit.

- The first possibility is that load growth would fall from the expected 7-8% to, say, only 2-3%, circumstances under which the second and third units might see very long postponements. However, even if there is the occasional year that deviates from the long term trend (as occurred in 1996), the probability that there will be a marked deceleration of load growth implies a corresponding decline of the long term GDP growth rate. The latter outcome seems very unlikely given the consensus among all political parties for pursuing economic growth through liberalisation and reform. In fact, over the longer term, there may well be an acceleration of the growth rate once the security problems in the North have been settled.

- The second reason why coal fired units 2 and 3 would not be built is a fundamental change in the structure of international energy prices, under which oil (and LNG) would become much cheaper than coal. However, as noted, coal prices are not unrelated to oil prices over the long term. Thus, any prolonged decrease in oil prices are inevitably accompanied by a corresponding decline in coal prices, as manifestly evident from the recent experience.
- Even if over the next ten years a global carbon tax regime came into place, it is entirely unclear that this would necessarily result in a decline in oil prices relative to coal. While unit rates of carbon tax would certainly be higher on coal than on oil (and gas), coal producers are just as likely to reduce prices to maintain market share, and oil producers increase prices to capture the available premium. In any event, the impact of a plausible level of carbon tax is likely to be far smaller than the potential impact of geopolitical problems in the Middle East, concerted action by OPEC, or the full resumption of Iraqi oil production.11
- The third and final reason for concern would be the unexpected discovery of large natural gas resources in Sri Lanka -- which would put Sri Lanka in the same situation as New Zealand in 1979, (and which there resulted in abandonment of the Marsden B oil-fired station). However, if indeed this were to occur in Sri Lanka, the benefits to Sri Lanka of large natural gas fields would be so overwhelmingly large as to make abandonment of the coal plant a relatively minor matter (again exactly as in New Zealand with Marsden B). Moreover, if Units 2 and 3 at Puttalam were to be converted to gas, some part of the site infrastructure would still be useful to these units, though obviously not the coal unloading and handling facilities.

In short, it is highly unlikely that if a decision to proceed with coal were taken, that a coal project would be abandoned after the first unit).

2.8 Robustness to pessimistic assumptions

The robustness of the conclusions drawn here may be illustrated by a sensitivity analysis using very pessimistic assumptions for some of the input values about which there has been some disagreement. Indeed, a recent analysis by IFC comes to rather different findings, concluding that

> *The least cost options are CCGT and MSD)(medium speed diesels) at 4.2 and 4.3 cents/kWh, respectively . . . both steam options are costlier: oil-steam at 5.3 cents and coal at 5.3 cents.*[12]

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[11] The question of carbon offsets, and the related policy options available to the Government of Sri Lanka, is discussed in more detail in Meier, P. and M. Munasinghe, *Global Overlay Study of Greenhouse Gas Mitigation Options in the Sri Lanka Power Sector*, Environment Department, World Bank, Washington DC, December 1999.

[12] IFC, *Sri Lanka, Review of Thermal Options*, pg.3.

In Table 2.12 we present the results for a variety of deviations from our base case assumptions (with the least cost choice at each step shown in **bold face**). Since is there little disagreement over the role of CCCTs for intermediate loads, this analysis focuses on the technology choice for baseload among diesel CCCT, oil steam, coal, and medium speed diesels: we begin with the SLEPTA basecase, and then add each of IFC's key assumptions step by step. We also start with a world oil price of Brent at $17.3/bbl (Saudi Light $16/bbl) – which is representative of what most observers considered in 1999-2000 to be the likely future trading range of 15-20$/bbl. This assumption is already favorable to oil.

Table 2.14: Sensitivity analysis: Brent $17.3/bbl : US cents/kWh

	diesel-CCCT	*Medium speed diesel*	*oil-steam*	*coal-steam*
1. Base Case SLEPTA	5.21	4.94	4.36	**4.13**
2. 90%PLF for CCCT	5.08	4.94	4.36	**4.13**
3. Better heat rate for CCCT	4.88	4.94	4.36	**4.13**
4. Pessimistic heat rate for coal	4.88	4.94	4.46	**4.27**
5 IFC assumptions for non-fuel O&M costs	5.14	4.83	**4.68**	4.87
6 IFC's shorter plant lives for coal and oil steam cycle	5.25	4.97	**4.68**	4.94
7 IFC's capital costs for oil and coal steam cycle	5.25	4.97	**4.80**	5.58
8. IFC's capital cost for CCCT	4.99	4.97	**4.80**	5.58

Results for 10% discount rate[14]

The cases presented in Table 2.13 are progressive: each adds to the case before it, thus becoming progressively more favorable to CCCT, and less favorable to coal.

1. SLEPTA base case, see Annex Table A1.6 for details. We assume 80% PLF.
2. =case 1+ *Higher PLF for CCCT*. Assuming that CCCT would in fact be used for baseload, this technology offers high availability that may be contractually guaranteed by IPPs. In this case we increase the PLF for CCCTs to 90% (as in the IFC analysis (see Box 7).
3. =case 2+ *IFC heat rate for CCCT*: as discussed in Box 7 of the Detailed Report, the 7,500Btu/kWh rate used by SLEPTA may be improved upon in IPP operation (notwithstanding the contractual rate). This case uses 7,100 Btu/kWh as in IFC's analysis.

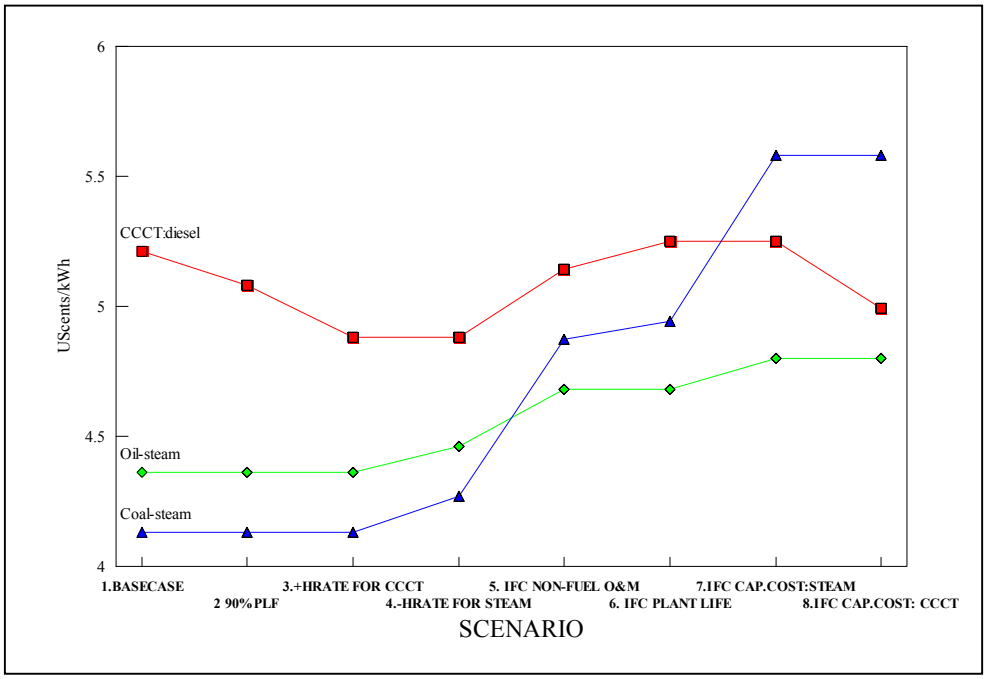
[13] In fact the IFC assumptions are not just pessimistic about coal, but also for CCCT. For example, it assumes a fixed operating cost of $30/kW for CCCT. Yet as noted in Table 3.1 of the detailed report, the AES quoted rate is $16/kw/year (including 11.3$/kW for insurance).

[14] It may be noted that the weighted cost of capital in the IFC analysis is slightly lower than 10%, at about 9.54% (based on 30% equity with a real return of 17.1%, and 30% debt at a real interest rate of 6.3%). However, as indicated by the sensitivity analysis of Figure 2.4, above, such small differences are not likely to affect technology rankings.

4. =case 3+ *IFC heat rate for coal and oil*, for which we take IFC's assumption of 9,800 and 9,500Btu/kWh, respectively. These are quite pessimistic for steam cycle units without FGD.
5. = case 4+ *IFC assumptions for non-fuel operating costs* (though these are, as noted in Annex I, quite pessimistic for *all* technologies).[15]
6. = case 5+*IFC assumptions for steam cycle plant life* (25 years for coal and oil rather than 30 as assumed in SLEPTA)
7. = case 6+*IFC capital costs for steam cycle plant* ($1,500 for coal rather than $1,146)

As is evident from Figure 2.6, where we display the results of Table 2.13 in graphical form, oil-steam replaces coal in case 5; but it is only in case 7 (i.e. using IFC's assumptions for capital costs), that coal becomes more costly than diesel-CCCT. However, even under these assumptions, oil steam cycle, not diesel-fueled CCCT, is least cost at this oil price.

Figure 2.6: Sensitivity analysis (Brent 17.3$/bbl)



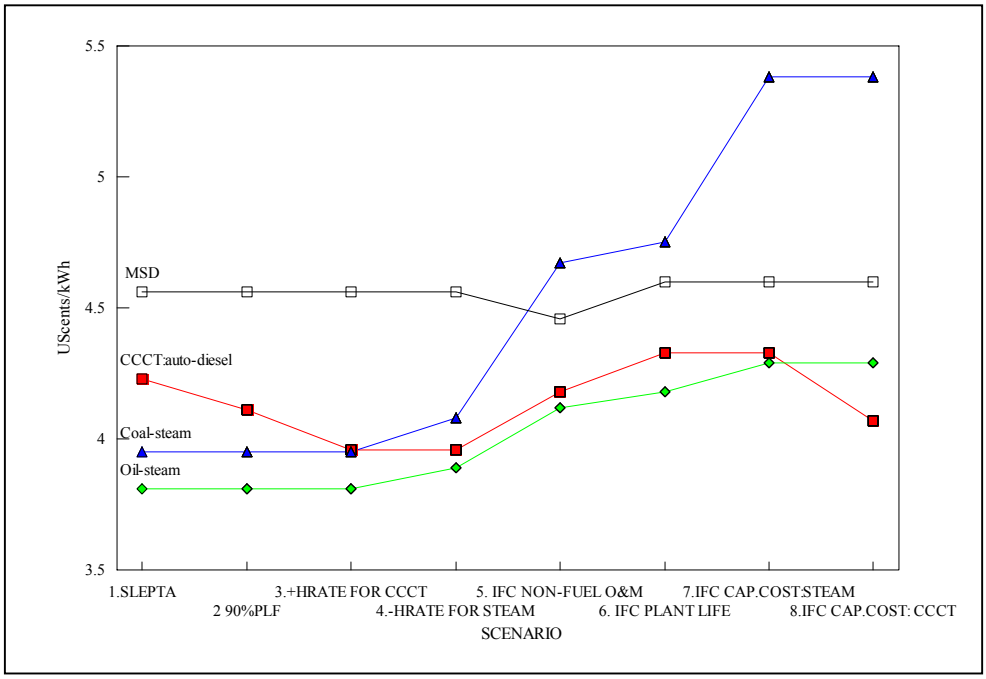
In Table 2.15 we show the corresponding analysis for a Brent price of 14.5$/bbl, the oil price used in the IFC analysis. At this oil price, the SLEPTA result is that oil-steam cycle is least-cost for baseload. And as shown in the Table and Figure 2.7, oil-steam is displaced from least-cost only by IFC's capital cost assumption for CCCT.

[15] In fact the IFC assumptions are not just pessimistic about coal, but also for CCCT. For example, it assumes a fixed operating cost of $30/kW for CCCT. Yet as noted in Table 3.1 of the detailed report, the AES quoted rate is $16/kw/year (including 11.3$/kW for insurance).

Table 2.15: Sensitivity analysis (Brent $14.5/bbl) : UScents/kWh

	diesel-CCCT	*Medium speed diesel*	*oil-steam*	*coal-steam*
1. Base Case SLEPTA	4.23	4.56	**3.81**	3.95
2. 90%PLF for CCCT	4.11	4.56	**3.81**	3.95
3. Better heat rate for CCCT	3.96	4.56	**3.81**	3.95
4. Pessimistic heat rate for coal	3.96	4.56	**3.89**	4.08
5 IFC assumptions for non-fuel O&M costs	4.18	4.46	**4.12**	4.67
6 IFC's shorter plant lives for coal and oil steam cycle	4.33	4.6	**4.18**	4.75
7 IFC's capital costs for oil and coal steam cycle	4.33	4.6	**4.29**	5.38
8. IFC's capital cost for CCCT	**4.07**	4.6	4.29	5.38

Figure 2.7: Sensitivity analysis (Brent 14.50/bbl)



In short, it is evident that IFC's conclusion that CCCT is least-cost for baseload is based largely upon its capital cost assumptions, the choice of $14.5/bbl as an oil price, and the use of a 150MW unit size for comparison purposes.

Given the uncertainty about the future world oil price, use of a single, and low, oil-price forecast[16] does not inspire much confidence about the robustness of the

[16] IFC states that ". . . the real cost of representative crude fluctuates in a narrow range around $14.5/bbl (1999) for the next ten years." Even if this is for Saudi Light (and the report does not say explicitly), it is lower than the Bank's own forecast (see Figure 2.12 of the Background Report), which assesses the price for the period 2000-2010 (in 1998$) in the range of $15.7-16.8/bbl.

conclusion.[17] Indeed, the sensitivity analysis presented here shows that at higher oil prices, *steam-cycle oil, and not CCCT*, is least cost under IFC's capital cost assumptions.

With regard to capital costs, it is clear that the use of $1,500/kW for coal makes this technology uneconomic no matter what the assumptions for other parameters. To argue that the economics of coal can be assessed by burdening a 150MW coal unit with the entire infrastructure costs for a plant in the 600-900MW size range hardly seems unbiased, and most certainly does not give fair consideration to the scale economies available for steam-cycle units (though, as noted elsewhere, we find auto-diesel fired CCCT to be least cost for intermediate duty).

With regard to the IFC assumption of $550/kW as a capital cost for a 150MW unit, this is certainly at the low end of the present cost range according to a recent Word Bank review of CCCT technology.[18]

> *In the range of 50MW-500MW costs range from $500/kW to $750/kW. It is noteworthy that GT manufacturers have currently little spare manufacturing capacity (due in large measure to strong sales in the North America) and this has possibly been a factor in causing prices recently to level off. Prices had been on a downward trend for some time.*

It may be noted that the effective economic cost of the competitively bid AES CCCT project is $644/kW[19], while the completed cost is $674/kW.[20] Moreover, it seems entirely unfair to compare the AES project cost, which is unburdened with any site or fuel infrastructure cost, with a coal project that is burdened with the full costs of *its* fuel infrastructure. There are significant fuel infrastructure costs associated with any green-field CCCT development -- which even if not carried by an IPP are certainly real economic costs to Sri Lanka.

The foregoing point is illustrated by the feasibility study for the proposed Kerawalapitiya CCCT project: costs for the power plant alone (first 150MWunit, including building, spare parts etc.) are $570/kW,[21] but when the costs of associated civil works, access road development etc are added, the total cost almost doubles (to $1,086$/kW).[22] In other words, if CCCT is held to the same assumption as the coal plant, i.e. that the first unit must carry the entire infrastructure burden, then a level playing field requires that if coal is costed at $1,500/MW, CCCT would be charged with around $1,000/kW. Even if the infrastructure costs are shared between two units, the cost falls to $840/kW. In light of such estimates, and the AES cost of $674 (which benefits from a fully developed site), the SLEPTA baseline assumption of $725/kW as a

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17 That is true even for an analysis whose pre-amble declares its purpose as a "preliminary analysis." (IFC, *op.cit.,* pg.1).

18 R. Taud, J. Karg and D. O'Leary, *Gas Turbine Based Power Plants: Technology and Market Status*, World Bank, Energy Issues, No.20, June 1999, Washington DC.

19 Present value of the stream of fixed charges for capital recovery (comprising the equity returns and debt service, but exclusive of fixed O&M).

20 As per AES proforma, capital cost is $110million for a net capacity of 163.3MW.

21 Tokyo Electric Power, op.cit., Table 9-1-1

22 *Ibid*, pg. 9-1-2. Total cost for the first unit is $163million.

representative cost for a greenfield CCCT site hardly seems unreasonable, while IFC's $550/Mw appears low.

2.9 LNG

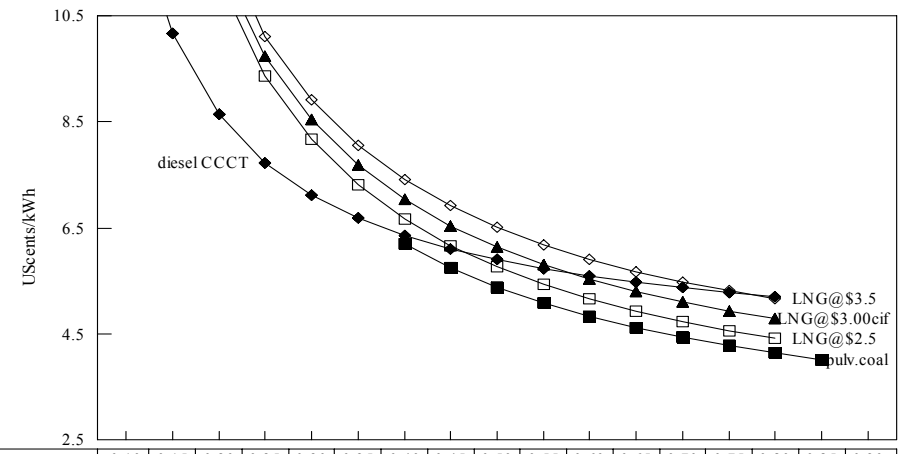
Even under the most optimistic assumptions about the scale of any LNG project, LNG is least cost only for intermediate duty (displacing diesel-oil fueled CCCTs). However, as revealed by the detailed review of Annex IV, and particularly the experience of India, Sri Lanka should view LNG with great caution, for both fuel and capital costs will be high at the scale possible for Sri Lanka.

It may be possible to reduce the cif price of LNG to Sri Lanka by a back-haul supply arrangement, as suggested by ENRON. However, at the economic 2-2.5 mtpy scale, the transportation cost accounts for only a relatively small component of the total, so even if a backhaul operation were feasible, and the savings passed through to Sri Lanka, the cif price reduction would be small. In other words, for a small, power only project, any savings in transportation cost through backhaul is likely to be offset by the diseconomies of scale. If the price at a large project of 2 mtpy is 5.6 UScents/kWh),[23] it is likely that the price of a *small* project (like in Sri Lanka) will be higher.

We have examined LNG in two different implementation modes (see details in Annex IV). The first is under the assumption of a 750 MW power-only project, for which we estimate the overnight capital cost (with penalty for up-front infrastructure) at $1,460/kW (including terminal and regasification). Then if LNG fob is priced at 2.81$/mmBTU (corresponding to an Arab Light price of $18.5/bbl), and an efficient backhaul transportation system keeps freight costs to 0.20cents/mmBTU, the cif Sri Lanka price would be $3.00/mmBTU. However, as shown in Figure 2.8, even at $2.5/mmBTU, LNG would not be competitive with coal.

[23] In the Background Report we analyse in some detail the economics of a large scale (2mtpy) LNG project proposed for Pakistan.

Figure 2.8: Screening curves for LNG (power-only project)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ diesel CCCT	13.21	10.16	8.64	7.72	7.11	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ LNG@$3.00cif	20.58	14.56	11.55	9.75	8.54	7.68	7.04	6.53	6.13	5.81	5.53	5.30	5.10	4.93	4.78		
⊟ LNG@$2.5	20.21	14.19	11.18	9.37	8.17	7.31	6.66	6.16	5.76	5.43	5.16	4.93	4.73	4.55	4.40		
◇ LNG@$3.5	20.96	14.94	11.93	10.12	8.92	8.06	7.41	6.91	6.51	6.18	5.91	5.68	5.48	5.30	5.15		
△																	

The corresponding total life-cycle costs are indicated in Table 2.15. The probable minimum price of LNG for 18.5/bbl is 3.0$/mmBTU, falling to 2.75$/mmBTU at $16/bbl (for which the NPVs and penalties are shown in boldface). We note that cost differentials are significantly higher than the difference between coal and oil steam-cycle (as shown, for example, in Table 2.9).

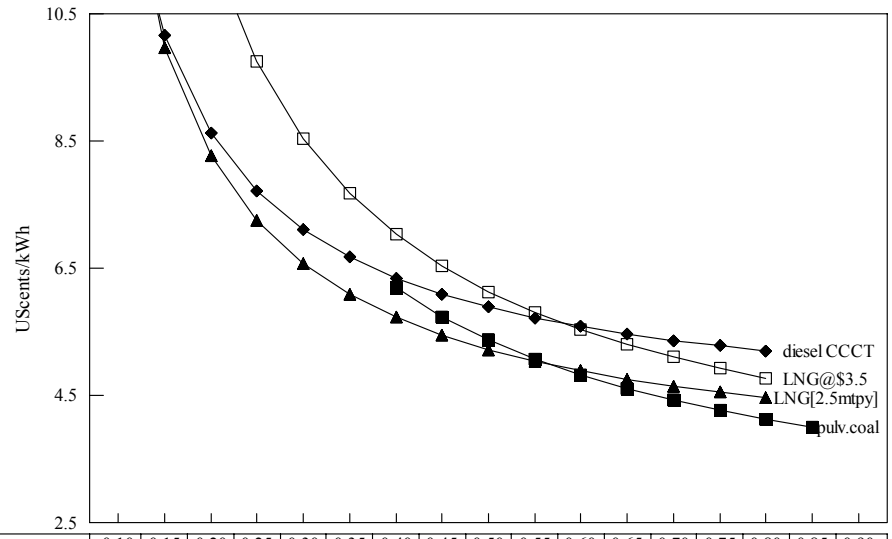
Table 2.16: Lifecycle costs ($USmillion,NPV at 10%), 75%PLF

	Arab Light =18.5$/bbl		*Arab light=16$/bbl*	
	NPV	*□[coal]*	*NPV*	*□[coal]*
Coal	794		776	
LNG@ 2.5$/mmBTU	846	52	846	70
2.75	881	87	**881**	**105**
3.0	**916**	**122**	916	140
3.5	986	192	986	210

The second mode of implementation assumes that the project would be of much larger scale, with significant non-power off-take of gas (which, as argued in Annex IV), would require a large additional infrastructure cost. Under such circumstances, the delivered gas price to the power project would be around 3.75/mmBTU (though with a capital cost limited to the much lower CCCT price of $725 /kW). Since the power generation costs themselves are the same as for diesel-CCCTs, and the diesel price is $5.05mm/BTU (at the same assumed crude price of $18.5/bbl), then any LNG price less than $5.05 mmBTU would be competitive for intermediate duty.

The resulting screening curve is shown in Figure 2.9. As expected, under these assumptions, LNG is least cost for intermediate duty. However, we note that above 55% load factor, coal is again least cost -- a result that is consistent with Japanese operating practice.

Figure 2.9: Screening curve for LNG: 2.5mtpy LNG project



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ diesel CCCT	13.21	10.16	8.64	7.72	7.11	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ LNG[2.5mtpy]	13.36	9.97	8.28	7.26	6.58	6.10	5.74	5.45	5.23	5.04	4.89	4.76	4.65	4.55	4.47		
⊟ LNG@$3.5	20.58	14.56	11.55	9.75	8.54	7.68	7.04	6.53	6.13	5.81	5.53	5.30	5.10	4.93	4.78		

2.10 Clean coal technologies

Atmospheric fluidised bed combustion (AFBC) is the clean technology that is closest to full commercial availability – though as noted in the introduction, its use is indicated mainly for poor quality coal (such as India's very high ash domestic coals). Its life-cycle costs are shown in Table 2.16. The magnitude of the incremental costs, compared to the baseline coal project, are significant, and higher than coal with FGD.

Table 2.17: Life-cycle costs (NPV, $US million)

	NPV	□*(coal)*
Coal	794	
coal+FGD	887	94
AFBC	917	123

Arab light 18.5$/bbl; 75% PLF, 10% discount rate

Table 2.18 shows the corresponding sulfur emission levels, together with those of some of the other options examined in this report. The trade-off between sulfur emissions and cost is shown in Figure 2.10. It is evident that for significant reductions in

sulfur emissions, FGD would be more cost effective than AFBC when using typical low-sulfur 0.5% Australian coal.

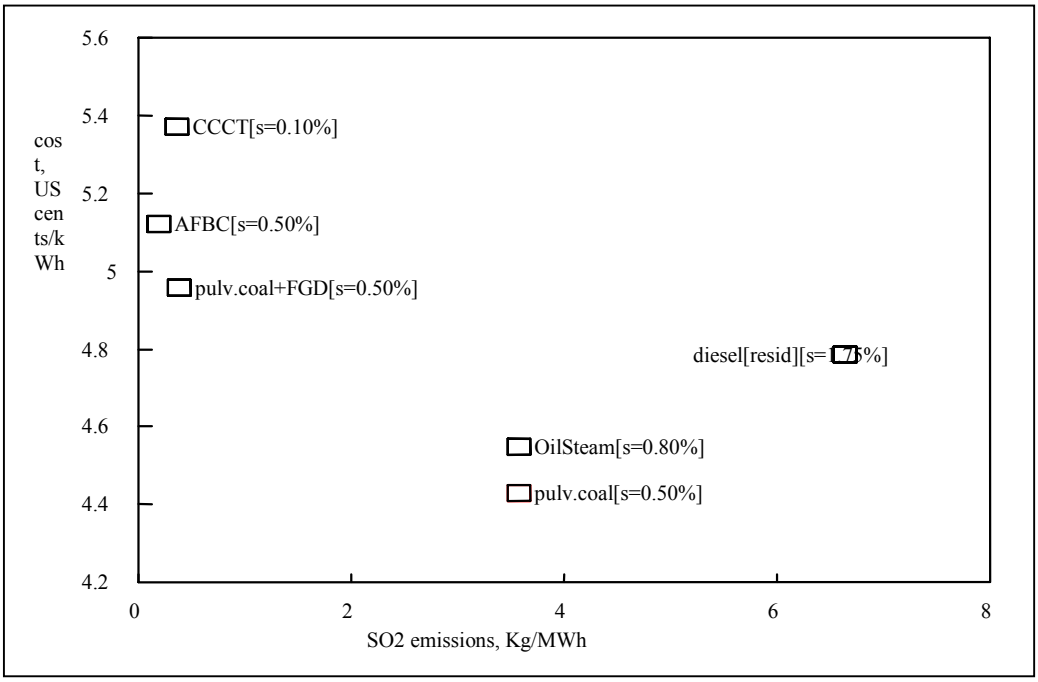
Table 2.18: Summary of sulfur emission levels

	mg/MJ	*$KgSO_2$ /MWh*	*tons/year for 300MW plant at 75%PLF*
proposed emission standard	520		
coal, 0.5%S ("average" e.g. coal at Puttalam project)	372	3.57	7030
oil-steam, 0.8% sulfur	372	3.57	7030
oil-steam, 1.1% sulfur(1)	520	5.28	10409
oil-steam, 1.6% sulfur (as proposed by ECNZ)			
CCCT, autodiesel 0.1%S	45	0.36	706
diesel using Residual (e.g. Sapugaskanda): at 1.75% sulfur(2)	813	6.64	13087
at 3.5% sulfur	1626	13.28	26174
coal + FGD	38	0.38	740
AFBC	19	0.18	359

(1) this is equivalent to use of 3.5% sulfur oil, treating 75% of the stack gas by FGD @ 90% removal.

(2) Though 3.5% S is the specification, actual sulfur content of fueloil used at Sapugaskanda is in the range of 1.75 to 2.25%S. Particularly in recent years this sulfur content has been lower than the specification, because the proportion of low-sulfur crudes has risen..

Figure 2.10: Trade-off between cost and sulfur emissions



2.11 Conclusions of the one-on-one technology comparisons

The most significant uncertainty in this analysis is capital cost. In the present highly competitive international power generation equipment market, capital costs for all power generation plant have fallen dramatically over the past few years (though particularly for combustion turbines). Nevertheless, the switching values analysis for capital costs shows that for baseload duty, only oil-steam running on heavy fuel oil, or diesel using residual oil, are in the competitive range with coal. Additional quantities of residual oil from the Sapugaskanda refinery would only be available if the refinery were expanded, which is unlikely for the time being. Therefore one may conclude that

1. For baseload duty, the steam cycle -- be it oil or coal -- is least-cost. This is not unexpected given that Sri Lanka does not benefit from low cost domestic gas (which often changes the economics in favor of combined cycle plants even for baseload).
2. For cycling duty with load factors in the 20-50% range, combined cycle plants using auto-diesel or naphtha are least-cost.
3. For thermal peaking, open cycle combustion turbines using auto-diesel are least cost.

Renewable energy and demand side management do have a role in Sri Lanka. If carbon offsets become available, the GHG study concludes that dendro-thermal projects may be attractive, initially by co-firing at coal projects. The study concludes further that mini/micro hydro, DSM and dendro-thermal all appear to represent better hedges against uncertainty in the value of the carbon offset than LNG. While the latter also reduces carbon emissions (relative to coal), it will expose Sri Lanka to undesirable lock-in effects.

The error introduced by averaging infrastructure costs over multiple units appears to be small. Only if a site is *not* developed to its full potential as assumed in the calculation of the averaged cost of the first unit, is the effect significant. Nevertheless, for future WASP studies, we recommend adjustment of capital cost inputs to account for this effect, estimated at 1.07 in the case of the 3x300 MW Puttalam coal project unit.

Application of clean coal technology does not appear to be warranted for Sri Lanka. The technologies that are at or close to commercial availability -- such as atmospheric fluidised bed combustion (AFBC) -- are most appropriate at mine-mouth plants using low quality coals (and hence their potential application in India and China). But because Sri Lanka has no indigenous fossil resources, and must import high-quality coal over relatively long distances, the economic rationale for AFBC is absent.

LNG does not appear to be a viable power technology for Sri Lanka for the next decade. It is extremely unlikely that LNG would be offered in any competitive process for either baseload or intermediate load duty.[24]

[24] This raises the question of whether, in an RFP for new capacity, the choice of fuel and technology should be left to bidders. In the case of LNG, leaving this as an option for bidders would certainly settle the debate (and inevitably in favor of other fuels). However, if the fuel is left to the choice of

bidders, there need to be established, in advance of the RFP, very clear principles of how risks are to be allocated, and on what basis relative fuel prices will be evaluated. Given the inevitable problems of delay, keeping the RFP, and the evaluation criteria, as simple as possible, argues in favor of the fuel/technology choice being made by CEB. However, once the power sector has been reformed, a more sophisticated system may be instituted.

3

Financial Analysis

3.1 Impact of fuel taxes

The first difference between economic and financial costs concerns transfer costs -- customs duty on equipment, excise taxes, defense levies, taxes (and subsidies) and duties on fuels. Even if investment decisions are made on the basis of economic costs, whether these transfer payments have a seriously distorting *economic* impact depends, in turn, on

1. The criteria for dispatch -- i.e. whether dispatching is done upon the basis of economic or financial marginal cost. If dispatch is done on the basis of financial cost (to CEB), then, obviously, the consistency of energy taxes becomes an issue. And if investment decisions are made on the basis of economic dispatch in a system planning model, but actual dispatch is on a financial basis, resources may be misallocated.
2. The extent of discrimination against IPPs. If for example, CEB is exempted from duty on liquid fuels, but an IPP is not, then if dispatch is based upon financial marginal costs, the effect may be to discriminate against dispatching an IPP.
3. Even if the equity returns were guaranteed to the IPP through a fixed charge (with additional incentives tied not to generation but to availability[25] -- so that there is no financial discrimination to the IPP from non-optimal dispatch) -- a more efficient IPP may be dispatched less, if it is burdened with a higher tax rate on fuel, than a less efficient CEB-owned plant. This may lead to higher than necessary fuel imports.

Taxes on liquid fuels used in power generation are shown in Table 3.1.

[25] However, at least in the case of the KHD (AsiaPower) project PPA, this is not the case, since it operates under a PPA with a take-or-pay contract for 330 GWh (75% PLF) as minimum guaranteed energy per annum, and with further incentives for production beyond this minimum. As noted by the recent ADB review (ADB, *Energy Sector Strategy Study*, May 1998), the interests of CEB and KHD may diverge in the long run, because once higher efficiency plants are brought on-stream KHD may meet its guaranteed minimum only by operating out of merit order.

Table 3.1: Taxes on liquid fuels for power generation (February 2000)

	Cif Colombo, 11/8/99 Rs/ton	*Price charged by CPC Rs/ton*	*Bank charges, port dues etc.*	*Total tax, Rs/ton*	*%tax*
	[1]	*[2]*	*[3]*	*[4]=[2]-[1]-[3]*	*=[4]/[1]*
Barge Project (IPP), 180cst fueloil	9067	12371	742	2562	28.20%
AES project (IPP)	12000	18597	804	5993	49.90%
Sapugaskanda diesels (residual oil)	8807	12033	736	2490	28.20%
Kelanitissa gas turbines (CEB)	12000	18597	804	5793	48.20%
AsiaPower	8807	12033	736	2490	28.20%
Lakdanavi, 180cst fueloil by bowser	9067	12371	742	2562	28.20%

Source: CPC

It is evident from the above that the rate of customs duty on imported diesel (30% of cif) is significantly higher than the customs duty on fueloil (10%). *Prima facie*, at least according to this nominal pricing structure, IPPs and CEB are subject to the same taxes. However, we understand that CEB has been (or will be) exempted from some or all fuel taxes except the defense Levy. If these same concessions are not also given to IPPs, then the previously noted distortions may well arise. Similarly, given the above structure of levying taxes and duties on oil, then distortions would occur if similar taxes are not also levied on coal.

The World Bank has previously recommended a simplification of the petroleum tax system:

> *The present structure of duties, taxes and levies on petroleum and petroleum products is very complex . . . There is a strong case for simplifying the present system of taxation to have a single point application and collection at the retail level and to save high administrative costs. It is therefore recommended that the Government introduce a simplified taxation system by, for example, combining all taxes and levies into a sales tax on the final retail price.*[26]

Such a simplified system would be desirable also from the power sector point of view. A full analysis of the impact of differential rates of taxes and duties on economic dispatch is beyond the scope of this present study, but should be undertaken. Such a study ought also to examine the impact on dispatch of PPAs signed to date with IPPs. But whatever may be the distortions introduced by these issues under current arrangements, the small size of such plants (48 MW in the case of AsiaPower, 20 MW in the case of Lakhdanavi) ensures that their impact is relatively minor. However, once the 150 MW AES and 60 MW Barge projects come on stream, particularly once they get displaced by

[26] World Bank, Energy and Project Finance Division, Country Department I, South Asia Region, Sri Lanka, *Petroleum Sector Study*, September 1996.

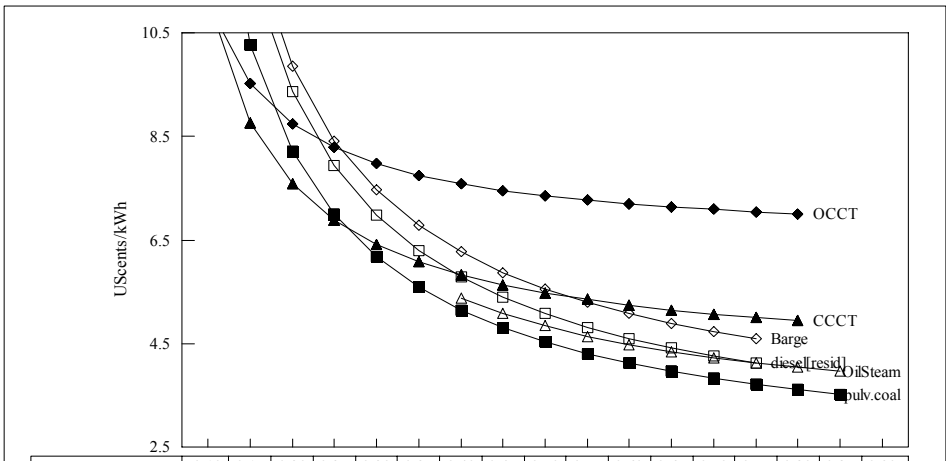
any baseload project in the merit order, the impact of such distortions may become more serious.

3.2 Impact of the financial cost of capital

However the more important issue that potentially affects investment decisions is the financial cost of capital, and the extent to which the financial cost of capital differs to the SDR used for economic analysis. Annex VI provides further details.

For the screening curve analysis using financial capital costs, the question of interest is whether the technology rankings change at the costs of capital that reflect concessionary or private financing. Figure 3.1 shows the results for concessionary financing taking the cost of capital at 7%, which corresponds to OECF financing. It is evident that the advantage of coal over oil-steam (other things like oil price being equal) is more pronounced at this lower cost of capital, as indicated in Table 3.2. Indeed, these lifetime costs shows that even at $13/bbl, coal still has an advantage over oil-steam.

Figure 3.1: Screening curves for OECF financing (cost of capital=7%)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal	14.37	10.27	8.22	6.99	6.17	5.58	5.14	4.80	4.53	4.30	4.12	3.96	3.82	3.71	3.60	3.51	
◆ OCCT	11.07	9.52	8.75	8.28	7.97	7.75	7.58	7.46	7.35	7.27	7.20	7.14	7.09	7.04	7.00		
▲ CCCT	11.11	8.76	7.59	6.88	6.41	6.08	5.83	5.63	5.47	5.34	5.24	5.15	5.07	5.00	4.94		
⊟ diesel[resid]	16.52	11.75	9.37	7.94	6.98	6.30	5.79	5.39	5.07	4.81	4.60	4.41	4.26	4.12			
◇ Barge	17.01	12.24	9.85	8.42	7.46	6.78	6.27	5.87	5.55	5.29	5.07	4.89	4.73	4.59			
△ OilSteam							5.37	5.07	4.83	4.64	4.48	4.34	4.22	4.12	4.03	3.95	

Table 3.2: Lifetime costs at 7% cost of capital (OECF financing)

	$13/bbl		*18.5$/bbl*	
	NPV	*□(coal)*	*NPV*	*□(coal)*
coal	855		906	
CCCT	947	92	1224	317
diesel (residual)	902	40	1008	102
diesel (furnace oil)	1018	162	1124	217
oil-steam	866	10	1008	102

3.3 Conclusions on financial analysis

The financial analysis permits the following conclusions

- While OECF financing at interest rates of 2% and less appears very attractive, the effective cost of capital is likely to be higher as a consequence of the probable continued depreciation of the US$ against the Yen.[27] Depending upon assumptions, the actual effective cost of capital may be several percentage points higher.
- Nevertheless, the effective capital cost of OECF financing (defined as the present value of the stream of equity returns and debt service payments) is still substantially lower than an IPP financing. Even if the dollar:Yen depreciation rate is taken as an average of 4%, and the IPP financing contains no Yen debt component, the difference is in excess of $300 million. Differences of this order of magnitude are significantly greater than differences between technologies.
- At the lower costs of capital implied by concessionary financing, the more capital intensive technologies will have an advantage. In the case of coal v. oil-steam for baseload, under OECF financing coal has an advantage even at oil prices of as low as $13/bbl (under baseline assumptions for capital cost). It seems reasonable to conclude that *if* OECF financing is accepted, coal is the most cost-effective (and robust) technology/fuel choice.
- However, at the higher costs of capital implied by IPPs, the advantage of coal over oil steam cycle is less clear, particularly at low oil prices.
- The analysis of the fixed charges for the proposed Marsden B project[28] shows clearly the importance of competitive bidding, and the potentially high cost of capital implied by the high returns to equity that are characteristic of projects implemented under MoU rather than ICB arrangements. The presentation of capital cost by IPPs give a misleading picture of the true cost of capital, since the effective cost of capital investment will be given by the present value of the stream of fixed plant charges (equity returns and debt service). In the case of the latest ECNZ offer for Marsden B, this actual cost of capital amounts to $353 million -- compared to the $195 stated to be the completed capital cost. We note that such differences are again not only greater than the differences between technologies (for equivalent duty), but are even comparable to the differences between private and concessionary financing.

[27] The impact of the dollar to Yen depreciation rate is discussed in Annex VI. Depending upon assumptions about the Yen component of non-concessionary financing, the actual cost of capital of Yen concessionary finance is likely to be several percentage points higher than typical nominal rates of less than 2%.

[28] This project proposal is discussed further in Annex V of the Background Report.

- The differences in cost attributable to differences in debt financing terms are also far smaller than the range of costs implied by the variations in equity returns encountered in MoU negotiations.
- Even if OECF funding for power projects were tied (i.e. not immediately available to other sectors such as health and education, were the power project to be funded by some other means), the opportunity cost of capital should still be taken at the SDR (10% as assumed here) – notwithstanding that the actual financial costs are significantly lower.[29]

[29] One of the arguments against concessionary financing is that this creates an additional actual or contingent liability upon the Government for which there may be limited headroom. On the other hand, if sovereign guarantees are offered to IPPs, the Government incurs an even larger contingent liability (since the amounts to be guaranteed to IPPs are very much larger than in the concessionary financing case because the cost of capital is also higher).

However, this is a transition issue. Sovereign guarantees may need to be offered to the first few IPPs, but subsequent projects may be able to proceed without them (provided power sector reform as a whole proceeds satisfactorily, and that the regulatory commission establishes a track record of adequate tariff-setting). Indeed, this is the experience in India, where the first few IPPs (the "seven so-called "fast track" projects, Including ENRON's Dabhol project) received federal guarantees, but none are to be given in the future. Nevertheless, the experience with the Indian guarantees is poor: several of the fast track projects went ahead without the guarantees, as administrative delays in Delhi were almost impossible to resolve.

4

Power Systems Planning Studies

Simple one-on-one comparisons and screening curves as used above, while transparent, have important limitations. They cannot say anything about *when* investment decisions should be made; about the optimal *size* of plants required to meet given load increments; or about the *mix* of peaking, intermediate and baseload plants that are required to meet given levels of reliability. Only more sophisticated systems planning models are suitable to answer these latter questions (although as we note below, even system planning models should not be used as the sole basis for decisions, and need to be supplemented with other decision-analysis tools). In this section we therefore turn to such a power systems analysis using the ENVIROPLAN model.[30]

4.1 Free run

We begin with a free run of the systems planning model, i.e. one in which the only plants forced into the system are those actually under construction. We use the CEB 1999 baseline forecast,[31] which projects for the next decade annual increases in peak load of between 100 and 150MW per year. A first question, therefore, is whether 300MW size increments for baseload additions – as proposed by CEB's consultants – is appropriate, or whether smaller units that more closely match the annual growth increments would be more economic.

[30] Developed originally for Sri Lanka by the World Bank's Environment Department (Meier and Munasinghe, *op.cit.*), it has since been used in a wide range of other countries and applications e.g. by the Canadian utility British Columbia Hydro for strategic planning (BCHydro, 1995 Electricity Plan, Vancouver, BC, September 1995: Volume C of this Plan presents the economic and trade-off analysis); by USAID (*Integrated Resource Plan for Andhra Pradesh*, Report to APSEB, Hyderabad, 1995); by the World Bank in 1997 and 1998 for the economic appraisal of power sector reform programmes in the Indian States of Haryana and Andhra Pradesh (*Economic Analysis of the Haryana Power Sector Restructuring and Reform Program*, World Bank, New Delhi, 1997; *Economic Analysis of the Andhra Pradesh Power Sector Restructuring Program*, World Bank, New Delhi, January 1999); and by the World Bank in an on-going study of Environmental Issues in the Indian Power Sector.

[31] Further details of the load forecast are presented in the Background Report.

There are three parts to the issue. The first is the purely technical question of system stability under dynamic conditions and outages, which argues for the smaller size. This has been studied by CEB, who find that 300MW units can be accommodated without difficult.[32] The second concerns the relationship between unit size and forced outage and scheduled maintenance rates, which affects plant availability.[33] And the third -- likely to be the most important -- is the purely economic one of the trade-off between economies of scale versus unused capacity. Some simple calculations confirm that 300 MW units are more economic.[34]

The only plants taken as committed are those actually under construction, or where contracts have been signed (Kukule, Barge BOO project, etc.). For each generic generation option a first possible start-up date had to be specified: in the case of baseload steam cycle (coal or oil), this is 2004; in the case of combined cycle plants, 2001. Five hydro project candidates were offered: Ging Ganga, Broadlands, Uma Oya, Upper Kotmale and Moragolla.

The results (Figure 4.1) show that a 300 MW coal base-load plant is built in 2004, and a second unit in 2007 (and the third in 2010). Two 150 MW combined cycle units are built to their earliest startup dates in 2001 (that correspond to the AES and OECF Kelanitissa projects), with further CCCTs units built in and after 2008. None of the hydro candidate plants are built.

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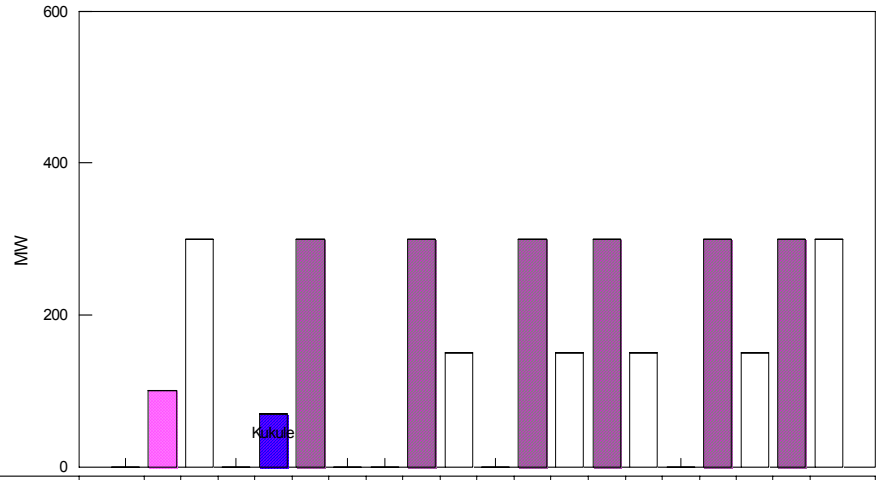
32 The Electrowatt Thermal Options study states "*Conventionally, maximum unit size is taken at around 15% of maximum demand so as to avoid excessive frequency disturbances on loss of a unit, particularly at light load."* However there are many utilities that adopt a more restrictive rule of thumb at 10% of the peak demand, particularly for non-interconnected systems. Based on this argument Electrowatt concludes that "the demand therefore indicates that a unit size of 150 MW is indicated initially, with 300 MW and perhaps larger sizes after 2005."

33 Larger unit sizes tend to have higher forced outage rates and longer scheduled maintenance times. According to the Electrowatt Thermal Options Study, 150 MW units have an 11% FOR and 35 days of scheduled maintenance, while 300 MW units have a 10% FOR and 50 days of scheduled maintenance. When both are combined, 150 MW units would have an annual availability that is 8.5 days/year higher.

34 Since the capacity expansion plan suggests that the second 300 MW coal unit would be required four years after the first, the alternative might be two 150 MW units with the second unit built after two years. A rough comparison would compare the cost of the 300 MW unit (at t=0) versus the present value of a 150 MW unit (at t=0) plus a second 150 MW unit two years hence. To be equal to the single 300 MW unit (1063$/kW), the 150 MW unit alternative would have to have a unit cost of 1163 $/kW (a ratio of 1.09). The data of Box 1, and general rules of thumb indicate that the actual multiplier would be at least 1.2, from which we may conclude that the 300 MW unit -- based purely on a simple economic analysis -- is to be preferred over two 150 MW units.

Figure 4.1: Expansion plan for free run (economic analysis) [plant capacities in net MW]



	1999		2001		2003		2005		2007		2009		2011		2013		2015		2017	
hydro					70															
coal						300			300			300		300			300		300	
liquid fuels			300		-44					150			150		150			150		300
gas																				
diesel		100									-36				-23					
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Model: **ENVIROPLAN**

1 Committed plants:

2 Barge (BOO), 60 MW: 2000

3 KfW Diesel extension at Sapugaskanda, 40 MW : 2000

4 Hydro: Kukule in 2003.

World oil price: 18.5$/bbl; discount rate 10%
Retirements shown as negative numbers.

4.2 Sensitivity analysis

A series of sensitivity analyses were conducted, whose main assumptions and results are summarised in Table 4.1. We draw the following conclusions:

- With respect to baseload additions for the base case load forecast, there was not a single run of the model that which did not build a 300 MW steam-cycle unit at the earliest assumed commissioning date. At low oil prices and low capital costs (relative to coal), the unit built was oil (e.g., case[7]); at higher oil prices and under baseline assumptions on capital costs the unit built was coal (e.g., case [6]).
- The conclusion that a *baseload* unit is required in 2004 is therefore robust. The results are sensitive to the demand that must be met. An aggressive programme of T&D loss reduction (case [5]) to bring losses to 12% from the

present 17.6% shifts the in-service date of the first baseload unit by one year (i.e. to 2005 rather than 2004 in the basecase).[35]

Table 4.1: Sensitivity analysis of the free run

		oil price $/bbl	*disc. rate*	*NPV $US mill.*	*□(base case)*	*summary of main impacts on expansion plan*
1	Free run: base case	18.5	10%	2250		coal units in 2004 and 2008
2	as [1], forcing in 150MW CCCT (Kerawalapitiya) in 2003	18.5	10%	2257	+7	next CCCT delayed from 2009 to 2013
3	as [1] but higher reliability	18.5	10%	2400	+150	coal units in 2004 and 2007
4	as [3] forcing in 150 MW CCCT (Kerawalapitiya) in 2003	18.5	10%	2412	+162	second coal unit delayed to 2008
5	T&D loss reduction (to 12%)	18.5	10%	2104	-146	First coal unit delayed to 2005
6	delay coal plant to 2006	18.5	10%	2297	+47	
7	delay coal plant to 2006 with 300MW CCCT to fill generation deficit	18.5	10%	2320	+70	next CCCT delayed to 2014
8	reduce oil price to 16$/bbl	16	10%	2133	-117	no change
9	as [7], 12% discount rate, reduce capital cost of oil steam-cycle	16	12%	2054	-196	oil-steam built in place of coal
10	as [1] but force in Upper Kotmale plant in 2006	18.5	10%	2296	+46	second coal unit to 2008; next CCCT delayed to 2012
11	Free run, but Upper Kotmale cost adjusted for OECF financing	18.5	10%	2231	-19	Build Upper Kotmale in 2009

- The costs of delaying the commitment to a baseload unit are consistent with those estimated on the basis of simple calculations -- around $70 million for a two-year delay with the generation deficit made up by CCCTs (case [6]).[36]

[35] At first glance this may seem counter-intuitive, since T&D losses are proportional to the square of the load, and hence T&D loss reduction would disproportionately benefit the peak demand periods. All other things equal, this might therefore be expected to change peaking rather than baseload capacity. But this is true only in a purely thermal system. In Sri Lanka's mixed-hydro-thermal system with substantial hydro energy, a greater proportion of the hydro used normally during peak hours will be available to fill base and intermediate loads, and hence the optimisation responds by reducing the expensive baseload capacity costs (where it can), rather than cheap thermal peaking.

[36] As discussed in the Background Report, the calculated cost of delay is a function of what one assumes is committed! If, for example, one treats the 150MW Kerawalapitiya plant as committed in 2003 (as does CEB's 1999 plan), then obviously the costs of delaying the coal unit from 2004 to 2005 or 2006 will be much less.

- For thermal peaking the timing and type of unit is critically dependent upon the reliability constraint. Even though a full risk analysis of this issue goes beyond the scope of this study, it is clear that relatively small changes in assumptions change the magnitude and timing of such units. One of the difficulties in power systems models is that while a reliability constraint (or minimum reserve margin) can be specified as an upper bound, the actual loss of load probability or unserved energy varies from year to year. Moreover, because of the discrete plant size (lumpy investments), it is very difficult to obtain *exactly* the same reliability level across different expansion plans.[37]
- The Upper Kotmale plant is not built in the free run (at 10% cost of capital). However, under OECF financing (case [10]), the *financial* costs are lower by $19 million.

Robustness to pessimistic assumptions

Parallel to the one-on-one technology comparisons based on pessimistic assumptions, presented in Section 2.8, we also ran a series of additional capacity expansion plans based on IFC's assumptions. The following were run as perturbations of case (3) in Table 4.1, with results as shown in Table 4.2 and Figure 4.2.

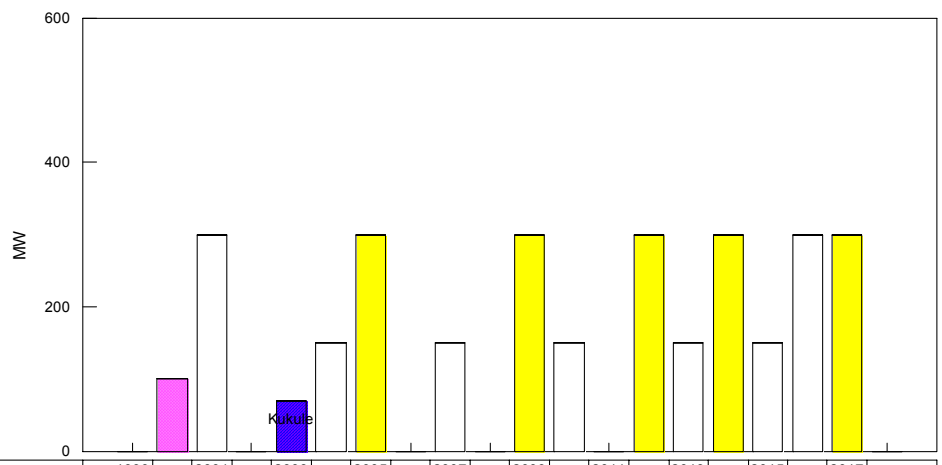
1. IFC's assumptions for heat rates (7100 Btu/kWh for CCCT, 9800 Btu/kWh for coal) at $17.3/bbl for Brent.
2. As Case 1 plus IFC assumptions for capital cost of auto-diesel CCCT ($550/kW)
3. As Case 2 but at $14.5/bbl for Brent
4. As Case 3 but with oil steam capital cost set at 70% of the coal capital cost.

[37] The Background Report discusses this point further in its Section 9.2.

Table 4.2: Sensitivity analysis: pessimistic assumptions

	Case	*PV, $US million*	*Impact on expansion plan*
	Base case Free run, $17.3/bbl for Brent (as case 3 in Table 4.1)	2400	
1	IFC assumptions for heat rates	2427	None: higher cost due to worse heat rates
2	As case 1 + $550/kW for CCCT	2369	None: lower system cost due to lower CCCT capital cost
3	As case 2 at $14.5/bbl for Brent	2118	None: lower costs due to lower oil price
4	As case 3, with oil-steam at 70% of capital cost of coal	2065	See Figure 4.2

Figure 4.2: Expansion Plan for case 4



	1999		2001		2003		2005		2007		2009		2011		2013		2015		2017	
hydro					70															
coal																				
liquid fuels			300		-44	150			150			150			150		150	300		
oil steam							300				300			300		300			300	
diesel		100									-36				-23					
renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

It may therefore be seen that there is indeed an adjustment in the capacity expansion plan at low oil prices ($14.5/bbl) and under optimistic capital cost assumptions for CCCT: the CCCT that in the basecase FreeRun is built in 2009 (Figure 4.1) now gets built in 2004, and the first large baseload unit is shifted from 2004 to 2005 (with parallel adjustments of later units). However, as also expected, it is oil-steam cycle that is used for baseload duty under these conditions, not auto-diesel fueled CCCT.

4.3 Impact of hydro conditions

To test the impact of system reliability assumptions we ran the expansion plan for very dry hydro conditions throughout the planning horizon, and found that there was no change in the expansion plan, though the PV of costs increased by $19million. This

result deserves explanation, particularly in light of the power shortages during the 1996 drought.

The capacity expansion plans presented in the previous sections are based upon the average of five hydro conditions – a standard procedure used also by WASP. The range of energy production between very dry, average, and very wet conditions is relatively small (2,900, 3,900 and 4,600 GWh/year, respectively). An expansion plan that is based on dry hydro conditions throughout therefore has to make up only about 1,000 GWh (i.e. the difference between average and very dry conditions) – which is a little less than a 150MW CCCT would produce at 80% annual PLF.

Beyond 2001 the system has at least 300MW of such capacity (AES and OECF naphtha fired unit at Kelanitissa), which once the coal units are in place after 2004 typically operate at 40% PLF (under average conditions). It therefore follows that in very dry years, the system responds by running the CCCTs at much higher PLFs (i.e. at 80% PLF) – and therefore dry conditions can easily be absorbed by increasing output without adjustment of the capacity expansion plan. However, in 1996, in the absence of sufficient thermal capacity, the resulting shortfall could not be made up, resulting in power cuts. In 2000-2001, with yet further procrastination by the Government in implementing the coal project, exactly the same happened again – lack of thermal capacity in an only slightly drier than normal hydro year resulted in prolonged and severe power cuts that significantly lowered GDP growth.

4.4 Choice of power systems model

WASP is the model used by the Ceylon Electricity Board (CEB) for generation expansion planning, and is the basis for its official generation plan issued annually.[38] The version currently used by CEB is WASP-IIIe, that is part of the Energy and Power Evaluation Program (ENPEP) software package developed by the International Atomic Energy Agency.[39] This is a detailed model providing a sophisticated dynamic programming analysis for capacity expansion and probabilistic production costing subject to reliability constraints. It is widely used for system planning in developing countries.

Given the criticisms raised by some that the recommendation for coal was a consequence of the choice of model, we considered it important to have an independent cross-check on the WASP model results. However, the power systems simulations undertaken for this study with ENVIROPLAN do not differ materially from those obtained by WASP. While a sample of two models is admittedly small, nevertheless we find that the differences attributable to the use of different models are far smaller than the differences attributable to assumptions. CEB's recommendation for coal as the preferred baseload fuel is a consequence of input assumptions, not of the model choice. Whatever criticisms may be appropriate to CEB's generation planning, choice of the WASP model would not appear to be among them.

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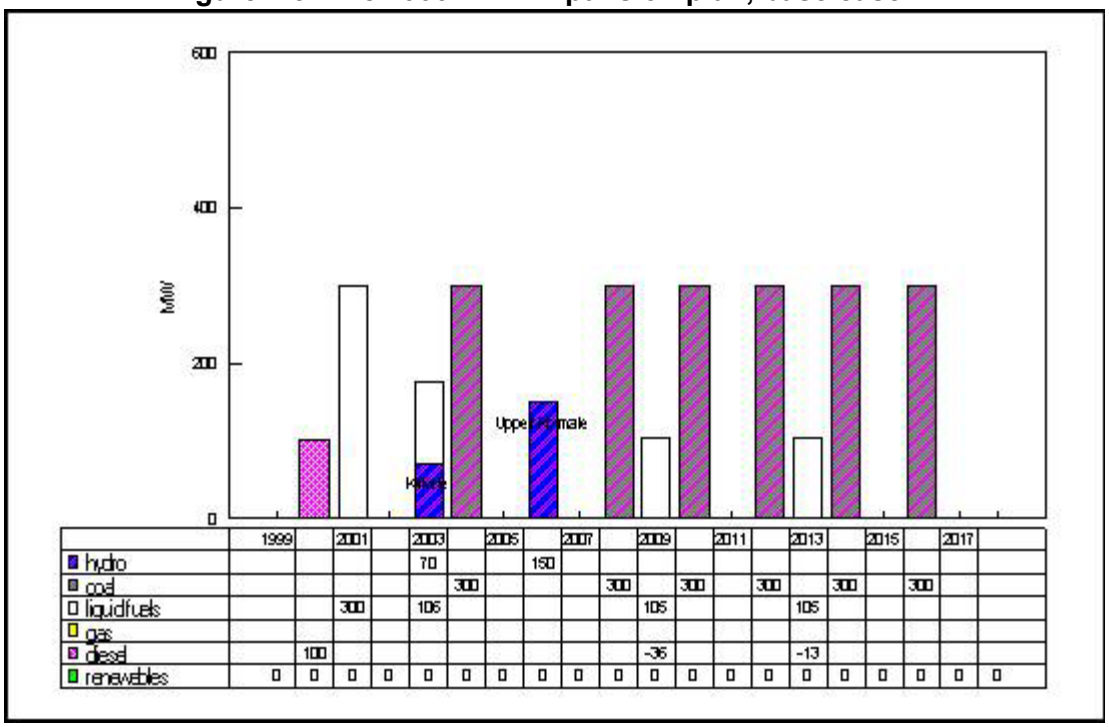
[38] The most recent published Plan is for 1998-2012, published in June 1998.

[39] A detailed description of the model, and its application to the CEB's generation planning studies, may be found in Chapter 7 of the CEB's 1998 Generation Planning Report.

4.5 The CEB expansion plan

CEB's 1999 base case capacity expansion plan is shown in Figure 4.3. A comparison with our own unconstrained, free run base case results is instructive.

Figure 4.3: The 1999 CEB Expansion plan, base case



Model: WASP

Assumptions:

cost of capital: 10%; world oil price (Arab light) $18.5/bbl

Committed plants: Barge (BOO), 60 MW: 2000

KfW Diesel extension at Sapugaskanda, 40 MW : 2000

AES CCCT 150 MW: 2001

OECF (naphtha CCCT) 150 MW : 2001/2002

Kerawalapitiya 150 MW CCCT: 2003

Coal West Coast Unit 1: 2004

Kukule 79 MW: 2003

Upper Kotmale 150 MW: 2006

Retirements: (shown as negative numbers) 44 MW oil steam (Kelanitissa) 2003; 36 MW Sapugaskanda in 2009; 22.5 MW Lakdanavi diesel in 2013.

There are important similarities between the results of our free runs and the CEB's 1999 expansion plan:

- Our free run builds a 300 MW coal unit in the earliest possible year in which such a unit is allowed, i.e. 2004. This result corresponds to the CEB plan. Thus CEB's treatment of the first such coal unit in 2004 as a committed plant does not affect the result -- even if this constraint is removed, the WASP model also builds a first unit in 2004. But our free run advances the cost of the second baseload unit to 2007.
- The CEB's treatment of the AES and OECF 150 MW CCCTs as committed is similarly confirmed by our free run, which also builds 300 MW of CCCT in 2001 in the absence of the commitment constraint.

On the other hand there is also a difference:

- Our free run does not build the 150 MW CCCT at Kerawalapitiya in 2003 (which is treated as committed by CEB). However, this is compensated in the free run by the earlier in-service date of the second coal unit, and an advance of the next thermal peaking addition from 2009 to 2008.

There are also some minor differences that are not material to any short-term decisions:

- We could find no basis for the inclusion of the 10 MW diesel plant projected by CEB for 2013. This is explicable only as an end-effect in the WASP model, although it has a negligible effect on the results.
- In general, the free run prefers CCCTs to the OCCTs projected by the CEB -- though both the free run and the CEB base case build the first such unit in 2009. However, with short gestation times for this type of capacity, this difference is of no consequence to decisions that must be made in the short term.

Therefore we may conclude that as far as the base-case is concerned, the free run conducted by us is in general agreement with the CEB's results.

However, the sensitivity analysis raises a number of questions. The first point concerns the low demand cases examined by CEB -- one due to lower T&D losses, the other to a lower GDP growth rate. In both cases, the first coal unit continues to be treated as committed in 2004 by CEB. In *our* free run, lower T&D losses results in a *deferral* of the first coal unit from 2004 to 2005.

Given the CEB's past record of failing to attain stated T&D loss reduction targets, it may well be reasonable for CEB to doubt whether the goals of the present loss reduction programme can be met. Therefore, it may not be prudent to defer a decision on the baseload unit premised on the promise of lower T&D losses. However, a lower T&D loss rate reduces the generation system NPV by around $150 million -- and these *exceed* the costs of delaying the coal plant by even two years (which we estimate at between $47-70 million).

It is evident that these kinds of issues can only be satisfactorily resolved by a formal decision analysis procedure, which not only calculates the real option values of delaying decisions, but which provides a transparent and complete analysis of the consequences of uncertainty.

The second point concerns the relationship between reliability objectives and the timing of thermal peaking. As noted, the free run does not build the 150 MW CCCT in 2003. However, when we force in this unit, the difference in system NPV is only $12 million (with the result that the second coal unit is shifted to 2007, identical to the CEB plan). Reliability improves, with an implied cost of unserved energy of US$1.50/kWh.

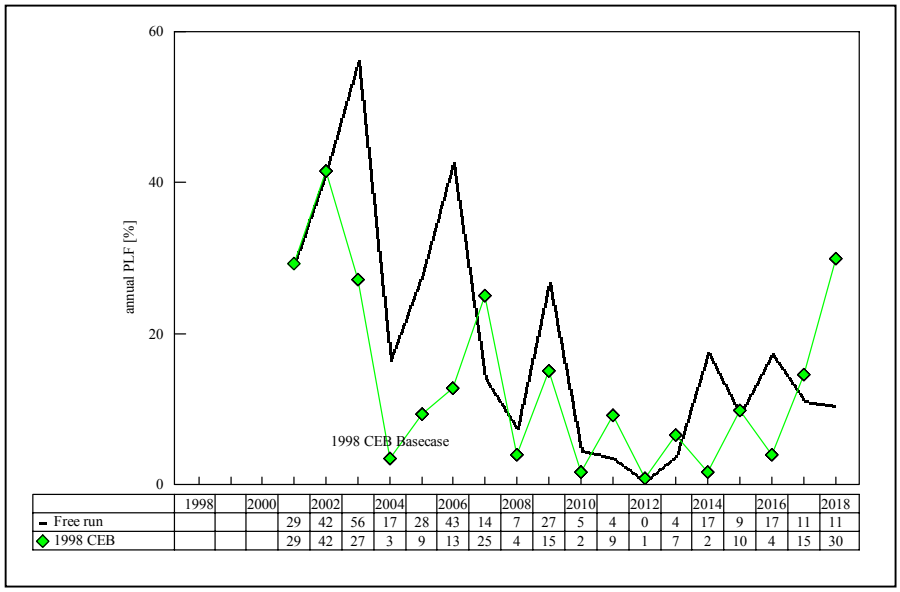
The 1999 CEB WASP runs imposed a reliability constraint that required a 10% reserve margin under the driest hydro conditions. As discussed in the Background Report, this results in rather lower LOLP than in earlier years. Although the trade-offs between reliability, cost, and the optimal expansion plan do not appear to have been systematically examined by CEB, our own (though admittedly limited) analysis of alternative hydro conditions and cost of unserved energy suggests that the optimal plan responds by adjusting the timing of intermediate-duty units. The need for baseload units is unaffected.

4.6 Transition issues

The dynamic performance of the power system is especially important in a system undergoing a transition from a publicly owned, vertically integrated monopoly to one where IPPs have a growing role, because assumptions about how IPPs would be dispatched at the time that PPAs are negotiated may or may not hold in practice.

This is illustrated by the example of Figure 4.4, where we show the annual PLF of the AES plant in the CEB Base case, and in our free run. Note the much lower dispatch in the CEB base case in the years 2004-2006, a consequence of CEB forcing in Kerawalapitiya (a plant not built in our free run basecase). These are averages over the five hydro conditions: in dry years, the annual PLFs would be significantly higher.

Figure 4.4: Merit order dispatch of the AES plant



	1998		2000		2002		2004		2006		2008		2010		2012		2014		2016		2018
Free run				29	42	56	17	28	43	14	7	27	5	4	0	4	17	9	17	11	11
1998 CEB				29	42	27	3	9	13	25	4	15	2	9	1	7	2	10	4	15	30

However, the more important points are

- that actual dispatch will not only vary from year to year, but over time gradually decline as newer thermal units (with better efficiencies) displace older plants in the merit order.
- that under economic dispatch, load factors may be significantly lower than presently contemplated (particularly if the coal plant is built). Consequently PPAs should be structured in such a way that the additional incentives to IPPs are related to availability, rather than generation.
- that dispatch should be on the basis of *economic* marginal costs, not financial consequence to CEB.

5

Summary

5.1 Main findings

The main conclusions of this study are as follows

- For baseload duty, steam cycle plant is indicated. While coal is least cost under most sets of assumptions, the switching value analysis suggests that steam-cycle oil plants, burning imported fuel oil (and blended to meet the proposed sulfur oxide emission standard) may be competitive at oil prices (Brent) consistently below $16/bbl. Combined cycle plants running at load factors exceeding 55-60% are not viable for baseload duty.
- For cycling duty, combined cycle plants burning auto-diesel or naphtha are indicated.
- LNG is not a viable option for Sri Lanka in the next decade. Even if the Puttalam baseload project were bid as an IPP and the fuel choice were left to the IPP to decide, it is extremely unlikely that any IPP would bid an LNG project (quite apart from the question of whether LNG could be unloaded at this exposed site). If a combined cycle project for the South Coast (say at or near Galle Harbour) were advanced, again it is extremely unlikely that an LNG-based project would be among the top-ranked proposals.
- If any additional combustion turbines are built in Sri Lanka (beyond the AES project), they should be fueled by naphtha (at least to the point at which in average hydro years, naphtha no longer needs to be exported).
- The case for the application of new clean coal technology to Sri Lanka remains weak, since it is significantly more expensive than FGD as a way of reducing sulfur emissions. However the available evidence suggests that air emissions from coal (and heavy oil) could meet the proposed emission standards without the need for the more expensive FGD or AFBC technology.
- Simple one-on-one comparisons (and screening curves) appear to give results that are consistent with those given by more sophisticated least cost system planning tools, and serve a valuable function particularly for sensitivity analysis which is more easily conducted in such simpler models. They also have the merit of transparency.

- But these simple tools also have important limitations. They cannot say anything about *when* investment decisions should be made; about the optimal *size* of plants required to meet given load increments, or about the *mix* of peaking, intermediate and baseload plants that are required to meet given levels of reliability. Only more sophisticated systems planning models are suitable to answer these latter questions (although as we note below, even system planning models should not be used as the sole basis for decisions, and need to be supplemented with other decision-analysis tools).
- The differences in lifecycle costs among viable technology options for the same duty (e.g. coal or oil-steam for baseload) are significantly smaller than the differences due to choice of financing (IPP or concessionary financing), or the costs of delay. It necessarily follows that the choice between coal and oil as a fuel is far less important than the choice of IPP or concessionary financing, or making decisions in a timely way.
- At the same time, without a more formal decision analysis, it is difficult to assess the real impact of uncertainty. The conclusions about the need for a baseload plant in 2004 are critically dependent upon assumptions about load growth, or, for example, whether the generation requirement can be reduced by T&D loss reduction or DSM. However, given the inevitable delays in implementing projects, it is clear that it is far preferable to err on the side of caution, especially when the costs of inadequate capacity during dry years may impose large economic costs (as occurred in 1996, and even more so in 2002-2002).
- However, one might more reasonably conclude that it is better to improve decision-making and project management through reform and restructuring. Indeed it is clear that the capacity shortages in the 1996 drought year were a consequence of the failure to make timely decisions for additional capacity, rather than poor forecasts of either demand or hydrology. In short, the results of conventional power system planning tools used in this report should be seen as *inputs* to a decision-and risk analysis, rather than as justification for a plan.

5.2 Recommendations for further analysis

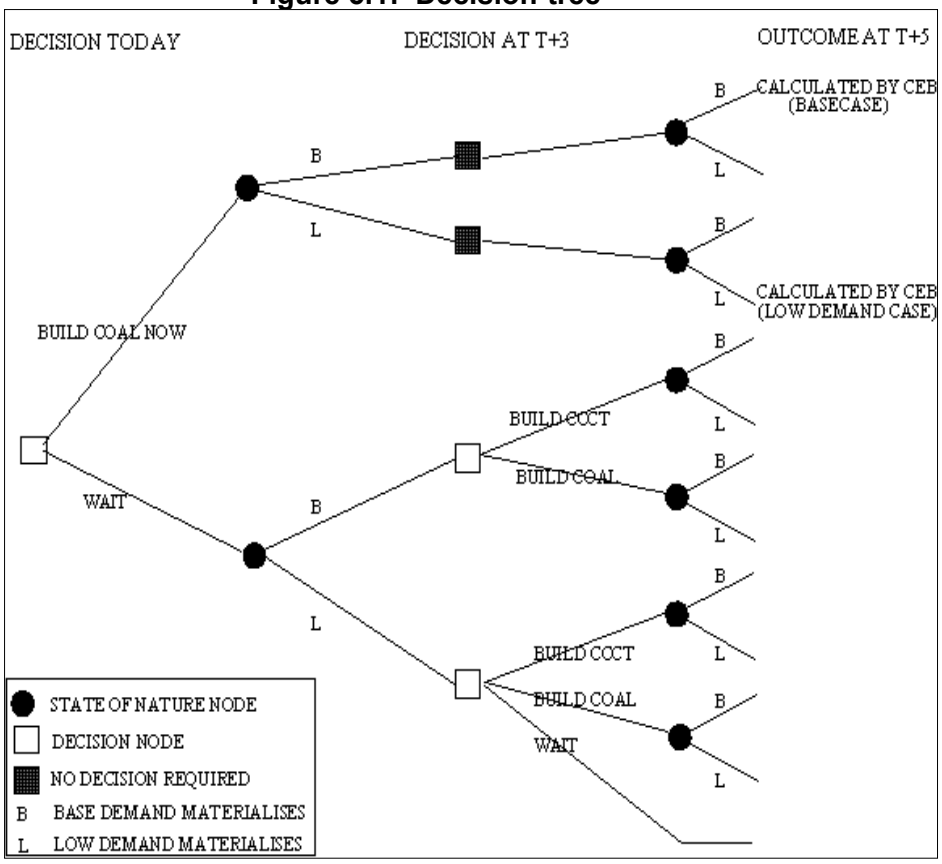
As is evident from the above, the classical tools of screening curves and power systems analysis tell only part of the story. These tools enable us to identify the consequences of particular sets of assumptions, but they do not necessarily clarify the critical decisions. What is needed is a decision analysis framework that includes a calculation of the real option value of alternatives (and of taking investment decisions).[40] Moreover, investment decisions in generation must be evaluated in the context of investments in other parts of the system, particularly T&D and T&D loss reduction.

Figure 5.1 illustrates such a framework – in simplified form. The typical question posed is whether one should commit today to the coal plant, or if there is any benefit to waiting so that uncertainties may be clarified? The (simplified) structure assumes two

[40] Such a real options framework was used in the Sri Lanka GHG Overlay study.

time points for decision: either today, or at T+3, when it is assumed that if high demand materialises, one could still build a short gestation plant (say CCCT) and meet the demand at T+5; but if low demand materialises, one can again wait, build coal, or build a CCCT.

Figure 5.1: Decision-tree



Each branch requires a run of the power systems planning model to calculate the present values of the outcomes at t+5. We note that the CEB generation plan examined only the two branches of the tree indicated -- both based upon a decision to commit today. But without knowledge of the consequences of the outcomes of waiting, the benefit (or cost) of a commitment today cannot be known.[42] We note that this approach is still based on a very simplified tree:

41 The optimal decision is assessed by first assigning probability distributions to the states of nature (in this example whether basecase or low demand growth actually materialise). Then the expected values are calculated from values estimated to occur at T+5, back through the tree (from right to left), to obtain the NPVs associated with the choices at the present decision point.

42 The optimal decision is assessed by first assigning probability distributions to the states of nature (in this example whether basecase or low demand growth actually materialise). Then the expected values

- it assumes that a commitment today to build the coal plant can in fact be implemented in the five year period assumed (which may in fact be dependent upon choices about how the project is implemented).
- it ignores the additional choices implied by different financing options (i.e. OECF v. IPP).
- it shows only two time steps (decision today or at t+3, outcome at t+5).
- it ignores the outcome of T&D loss reduction (which may reduce the generation requirement even if basecase GDP and consumer demand growth occurs).

A second priority for analysis is a more detailed look at the costs and benefits of dual (and even multi) fuel capability. With the economics of the oil steam cycle option so close to those of coal (at least when oil prices are below $20/bbl), the question of whether the incremental costs of dual fuel capability (additional storage/unloading facilities, boiler modifications) are less than the benefits to be obtained during periods of depressed oil prices[43] clearly merits further analysis.[44]

Finally, a full examination of the impact of fuel taxation and import duties needs to be conducted. Such a study should establish what distortions, if any, result from financial rather than economic dispatch. At the same time, one should examine the implications of take-or-pay clauses in PPAs.

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are calculated from values estimated to occur at T+5, back through the tree (from right to left), to obtain the NPVs associated with the choices at the present decision point.

43 This occurred from mid 1998 to early 1999 -- when any plant with such a capability would clearly have used oil rather than coal.

44 However this by no means suggest that a decision about the baseload unit should be further delayed while such studies proceed (though again, only actual calculation of the real option value would confirm this). In any event there may be additional benefit to considering such capability for the second baseload thermal unit (needed around 2007-2008), by which time the value of any carbon offset would be clarified. Oil plants have lower GHG emissions than coal, so a case could be made for carbon reduction payments.

Annex I: Basic Thermal Options

A1.1 Simple technology comparisons

In a simple technology comparison we calculate the average cost of electricity per kWh and lifetime NPV given capital cost, fixed and variable (non-fuel) operating costs, fuel cost, and heat rate, as a function of the number of operating hours each year. Capital costs are adjusted to account for construction periods of different lengths, and then annualised, based on economic life and a discount rate set equal to the opportunity cost of capital (taken here at 10%).[45] The cost of electricity, ***e***, in US cents/kWh, may be stated as

$$e = OMV + 1000\ F\ \square\ 100/\square\ + 100(k\ C^{*}\ CRF(r,n) + OMF)/(8.76\ PFa) \qquad \text{Eq.[A.1]}$$

where *OMV* = variable O&M cost in cents/kWh

F = cost of fuel, $/ton

□ = net heat rate, in KCal/KWh

□ = gross calorific value (GCV) of the fuel, in KCal/kg

OMF = fixed O&M cost, in $/kW/year

CRF(r,n) = capital recovery factor, discount rate *r*, economic life *n* (years)

C^{*} = overnight capital cost, in $/kW

C = $k\ .C^{*}$ = nominal economic capital cost = overnight cost adjusted for the opportunity cost of capital

PFa = annual plant factor

A1.2 Non-fuel O&M costs

Table A1.1 shows the assumptions as found in various Sri Lankan studies for non-fuel O&M costs.

[45] Notwithstanding the focus on economic analysis, in some of the technical literature on generation planning (such as the WASP User Manual published by IAEA), this adjustment is called "interest during construction." Indeed the WASP User Manual provides a set of tables for this adjustment based upon a theoretical "S" curve of the time pattern of construction period capital costs (see also below for a discussion about the consistency of this adjustment with estimates of construction outlays in detailed feasibility studies). The use of "IDC" in this context is unfortunate, for this adjustment (in economic analysis) has nothing to do with actual interest during construction relevant to financial analysis.

We note the following:

- The 1999 CEB generation planning study estimates for oil-steam are higher than for coal (e.g. variable O&M costs at 4.19 mills/kWh for oil as opposed to 2.79 mills/kWh for coal). This appears to be due to oil-steam units being taken as 150 MW units, whereas the figures for coal are for 300 MW units. This does not seem reasonable, since 300 MW oil-steam would be the indicated substitute for 300 MW coal units.[46] The 1995 Electrowatt thermal options study, however, shows the corresponding variable O&M costs as 2.98 mils/ kWh for oil v 3.54 mils/kWh for coal, which are in the correct proportion.
- Insurance costs in the IPP estimates are significant: in the AES cost breakdown, insurance more than doubles the remaining fixed O&M costs.
- The ECNZ estimates for oil steam-plant O&M costs are on the high side, roughly double those of Electrowatt (though again insurance costs may be an explanation).

Table A1.1: Comparison of non-fuel O&M costs

		fixed O&M $/kW/year			*var O&M mills/kWh*			*total annual cost $Year/year*		
		CCCT	*coal*	*oil-steam*	*CCCT*	*Coal*	*oil-steam*	*CCCT*	*coal*	*oil-steam*
Planning studies										
Electrowatt	900 MW[3]	3.18	7.74	6.51	2.27	3.54	2.98			
CEB 1998	300 MW	3.18	7.74		2.27	3.54				
CEB 1999	300 MW	3.36	6.73		2.72	2.79				
	150 MW	5.86		9.18	4.19		4.2			
IFC	150 MW[5]	30.00	40.00	24.00	3.0	4.0	2.0			
Detailed feasibility studies										
Electrowatt	900 MW[4]								8.19	
	300MW[4]								7.31	4.87
TokyoElectric[1]		5.8		9.1	4.17		4.16			
IPP estimates										
AES	150 MW	4.7			0.8					
		11.3[2]								
ECNZ	222MW			26.9			1.29			8.77

1 Tokyo Electric Power Services, Ltd, Kerawalapitiya CCCT Detailed Feasibility Study.
2 includes insurance (estimated at $1million/year); 4.67$/kW/year excludes insurance.
3 Electrowatt 1996 Thermal Options Study.
4 Electrowatt, 1997 *Detailed Feasibility Study of the 3 x 300 MW West Coast Coal Project.*

46 This bias is further compounded by the differences in capital costs of 150 and 300 MW units, and by the discrepancies in relative fuel prices (as discussed below, see Table A1.3).

[5] IPC, 1999, *Sri Lanka Review of Thermal Options*.

The 1998 CEB planning assumptions may be used except in the case of oil-steam, for which we use 5.76$/kw/year for fixed O&M, and 2.37 mils/kWh for variable O&M (which are in the proportion to coal given in the Electrowatt 1995 Thermal Options Study for comparably-sized plants).[47]

A1.3 Heat rate assumptions

One needs to be clear about the differences between inputs to WASP modeling studies -- which require specification of heat rates as full load, minimum load, and the average incremental heat rate -- and average values that are appropriate for economic analyses -- which need to reflect the probable operating conditions on an annual average basis. Since combined cycle plant efficiencies are particularly sensitive to part-load operation, the full-load values cited by some CCCT proponents need special scrutiny. For example, Electrowatt has noted that a 48.1% full-load efficiency of a CCCT plant would drop to 41.5% at the 66% load that is typical of nighttime conditions.[48] The corresponding annual average efficiency, appropriate for use in economic analysis, would be about 45.5% (and a heat rate of 1,890 KCal/kWh).[49] This is consistent with the value used by AES (see Table A1.2).

Table A1.2: Heat rate assumptions for combined cycle plants

	heat rate (net) KCal/KWh
AES proposal	1908
Kerawalapitiya (Tokyo Electric Power Services)	1968
Electrowatt, Economic analysis of coal-fired plant	1890
MottEwbankPreece/ECNZ	1736
ENRON	1700
CEB/Thermal Options Study:	1788
[WASP inputs]	2457
	1968
	2614

On the other hand, the value used by Mott Ewbank Preece (in its economic comparison with the ECNZ steam-cycle plant) is far too optimistic -- leading to a corresponding under-estimate of the annual fuel cost of about 9%. Similarly, the heat

[47] Namely 6.73$/kW/year for fixed O&M and 2.79 mils/kWh.

[48] Electrowatt, *Economic and Financial Analysis (of the Coal Fired Thermal Development Project, West Coast)*, December 1997, pg. 13.

[49] Electrowatt has reviewed manufacturers data for performance of CCCTs using different fuels (Thermal Options Study Table 3.5).

rate value for LNG-fired CCCTs given by ENRON in its June 1999 presentation[50] reflects full-load conditions, whose chances of being achieved as an annual average are nil. In this study, therefore, we use the Electrowatt value of 1,890 KCal/kWh for our economic analysis.[51]

A1.4 Fuel price assumptions

The Background Report discusses the need for consistency in fuel prices, particularly when fundamental assumptions -- such as the world crude price -- are changed in sensitivity analyses. Table A1.3 shows a comparison of the fuel price forecasts using the methodology derived in the Background Report, and the values used in the 1998 and 1999 CEB generation plans. The differences are small, except for fueloil and residual.[52]

Table A1.3: Fuel price comparisons in UScents/GCal: 1998 CEB generation plan: ($16/bbl Arab Light 34)

	1999 CEB Generation Plan	*SLEPTA Methodology*	*difference*
diesel	1654	1734	-80
naphtha [exports]	1572	1498	74
residual	943	704	239
furnace oil	1180	838	347
coal (West Coast)	746	738	8
coal (Trinco)	698	690	8

Source: CEB 1998, *op.cit.,* Table 1.4

A1.5 Adjusting overnight costs

As noted above, overnight costs[53] need to be adjusted for the opportunity cost of capital, since WASP (and the screening curve model used here) take a single value for capital cost (assumed to be incurred in the year before commissioning), whereas actual construction outlays are spread over a sequence of years. The WASP manual provides a table of such adjustment values, based upon a theoretical "S" curve for construction disbursements.[54] In the case of the coal plant with a 3.5 year construction period, this adjustment factor adds 16% to the overnight costs, and 13.54% to the overnight costs for plants with a three-year construction period.

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50 ENRON, presentation to CEB, June 1999.

51 We find similar discrepancies in the heat rate assumptions for steam cycle oil plants, as discussed below in Annex III.

52 However, the effect is again to bias the CEB analysis against oil-steam cycle using heavy fueloil (though not against CCCTs using diesel-oil).

53 CEB uses the equivalent term "pure construction cost."

54 International Atomic Energy Agency, *Expansion Planning for Electrical Generating Systems: A Guidebook*, Technical Reports Series 241, Vienna, 1984.

The theoretical S-curve pattern of disbursement as used by the WASP manual often does not match the actual time pattern of construction disbursements as estimated in detailed feasibility studies. For example, Electrowatt has estimated a disbursement pattern for the coal plant as given in Table A1.4, as used in their detailed economic analysis.[55]

Table A1.4: Construction disbursements, Unit 1, West Coast Coal[56]

	$US million	*fraction of total*
1999	46.87	0.15
2000	78.11	0.25
2001	109.35	0.35
2002	78.11	0.25

Source: Electrowatt, *Economic and Financial Analysis*, 10/12/1997; Table 3

It seems desirable that the adjustment used in WASP (and any screening curve analysis) be consistent with these detailed estimates.[57] The adjustment (as explained further in Box 1) calculates as follows, where r is the discount rate

$$k = 0.25 + 0.35(1+r) + 0.25(1+r)^2 + 0.15(1+r)^3 \qquad \text{Eq.[A.2]}$$

$$= 1.137 \text{ for a discount rate } r=0.1$$

Note that this value of 1.137 is somewhat smaller than the value of 1.16 that is given by the WASP manual for a plant with a four-year construction period. In the case of a similar calculation for the Kerawalapitiya plant, given the disbursement schedule of the detailed feasibility study, the corresponding value is 1.025, as compared to 1.1354 given in the WASP manual (for a three year construction period).

55 Electrowatt, *Economic and Financial Analysis*, 10/12/1997; Table 3.

56 Subsequent to this analysis, the schedule has slipped by one year, with commissioning now in 2004 rather than 2003, as assumed by Electrowatt in late 1997.

57 This adjustment is the k-value in Eq.[A.1], above.

Box 1: Adjusting capital costs used for WASP runs for up-front infrastructure costs

In order to eliminate the bias introduced by averaging of capital costs for multi-unit plants with high up-front infrastructure costs, the averaged unit costs used by WASP (or simple screening curve models) should be adjusted to eliminate the bias described in the text.

The required adjustment can be illustrated by the example of the West Coast Coal Plant. The table shows the timing of the capital outlays, assuming the commissioning schedule given by the CEB 1998 base case expansion plan. Columns 1-4 take the actual costs (with infrastructure costs burdened to the first unit), while columns 5-8 take the averaged costs. Costs are in $US million, and taken from the Electrowatt economic and financial analysis for the coal plant (see also Table A1.5)

	actual: infrastructure costs assigned to first unit				*averaged infrastructure costs*			
	unit1	unit2	unit3	total	unit1	unit2	unit3	total
sum	435	236	236	907	302	302	302	907
NPV@10%	338	125	103	567	235	160	133	528
2000	65			65	45			45
2001	109			109	76			76
2002	152			152	106			106
2003	109			109	76			76
2004		35		35		45		45
2005		59		59		76		76
2006		83	35	118		106	45	151
2007		59	59	118		76	76	151
2008			83	83			106	106
2009			59	59			76	76

While the **sum** of the costs are the same in the averaged and actual cases ($907 million), the NPVs are $567 million for the actual, and $528 million for the averaged. WASP sees the second, lower figure, and therefore the capital costs given to WASP for averaged units should be adjusted by the ratio of NPVs, i.e.

$$f = 567/528 = 1.07$$

This adjustment factor will of course depend upon the time staging of the units, the discount rate, and the degree of up-front loading of infrastructure costs. But since the timing of units is determined endogenously by WASP, unless several iterations are taken the value of f is necessarily approximate. However, such fine tuning is not indicated (given other uncertainties with much higher error bounds); and whatever the error involved in taking such an approximate value for f, it is certainly smaller than using averaged values which implies f=1.0.

A similar exercise for a 2 x 150 MW CCCT, based on the detailed feasibility study of the Kerawalapitiya project, results in adjustment of f=1.025.

A1.6 Infrastructure costs

ECNZ has made the following criticism of the economic analysis of the coal project:[58]

> *. . .The coal plant analysis includes infrastructure requirements (wharf etc.) which must be constructed at the time the first coal units are constructed. In the Electrowatt economic evaluation, these costs were evenly spread over all three stages of development, which has the effect of artificially reducing the cost of the coal development.*

The point is a good one. It would apply also to LNG, where the proportion of up-front fuel handling and infrastructure costs is even greater. CEB has also used averaged costs in its system planning studies.[59] As shown in Table A1.5, the capital cost for the first coal unit (when burdened with all the up-front infrastructure), is $1,451/kW, as opposed to $1,008/kW for the "average" unit, and $787/kW for Units 2 and 3.

Table A1.5: Unit capital costs of the coal plant ($US million)

	Unit 1 at actual	*Unit 1 at average*	*Units2&3 at actual*
outdoor site works	38.1	17.16	6.7
buildings and structure	32.9	26.29	23.01
steam generation plant	82.4	80.47	79.5
turbine generator plant	60.0	58.57	57.86
fuel and ash handling	25.5	12.17	5.5
balance of plant	32.7	20.05	13.75
electrical equipment: switchyard	19	15.45	13.7
Control &instrumentation	6.2	5.59	5.3
resettlement costs, environment, monitoring	1.5	0.5	0
	298.2	236.3	205.3
contingencies	14.9	11.82	10.28
Engineering & supervision	14.9	11.82	10.28
	328	259.9	225.85
coal unloading	65.29	21.55	
transmission	41.91	20.96	10.49
total	435.17	302.4	236.01
$/Kw	1451	1008	787

Source: Electrowatt, Economic and Financial Analysis, Coal-fired Thermal Development Project, West Coast" 10 December 1997; Table 1 (page 9).

But how significant is the impact of averaging on the levelised cost of electricity of a complete site development? Obviously if one looks just at the first unit, if burdened

[58] Letter of ECNZ to CEB, 12 November 1997.

[59] In the 1998 Study, CEB uses an averaged cost of 1243 $/kW for the West Coast coal project.

with all up-front infrastructure, its cost per kWh will be higher than if one uses just the average. On the other hand, the subsequent units will have a significantly lower cost/kWh.

Analysis of this question goes beyond the capacity of the simple screening curve model, and requires a more detailed economic analysis. This is provided in the case of the coal project in the Background Report.[60] The Electrowatt economic analysis of the West Coast coal project, using averaged infrastructure costs for the first 300 MW unit, shows a levelised electricity cost of 4.15 UScents/kWh.[61]

However, the analysis provided in the Background Report also shows that even if one takes actual disbursements for the West Coast project (with units commissioned as per the 1998 CEB expansion plan in 2004, 2008 and 2010), the levelised price (taking into account the output of the entire 900 MW plant) increases only to 4.23 cents/kWh. This suggests that the bias introduced by averaging is small, assuming that the site is actually developed to its full 900 MW potential.[62] Only if Units 2 and 3 were *not* built is the impact significant: in this case the cost of the first unit increases to 4.98 cents/kWh.

Burdening units of multi-unit sites with actual infrastructure costs requires somewhat tedious manipulation of the WASP model. However, this is not an issue for ENVIROPLAN, which can handle forced sequences of units at single sites, each with different costs. The ENVIROPLAN runs shown in this report all follow this more rigorous treatment -- though the results are little different to the WASP results using averaged costs. Nevertheless, for future runs, rigour requires that the averaged capital costs used for WASP be adjusted as suggested in Box 1.

A1.7 Screening curves

Table A1.6 lists the assumptions for the one-on-one comparisons based on an $18.5/bbl Saudi Light price (about 20.4$/bbl for Brent). It is assumed that oil-steam uses imported fuel oil blended to 1.63% sulfur.[63] The indicated capital costs are adjusted for opportunity cost of capital and the infrastructure penalty described earlier.[64]

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60 SLEPTA Background report, *op.cit*., Annex II: Impact of Infrastructure Costs.

61 Electrowatt, *Economic and Financial Analysis, Coal-fired Thermal Development Project, West Coast*, 10 December 1997: Table 3.

62 Though this bias may well be somewhat greater in financial terms -- see Annex VI for further discussion.

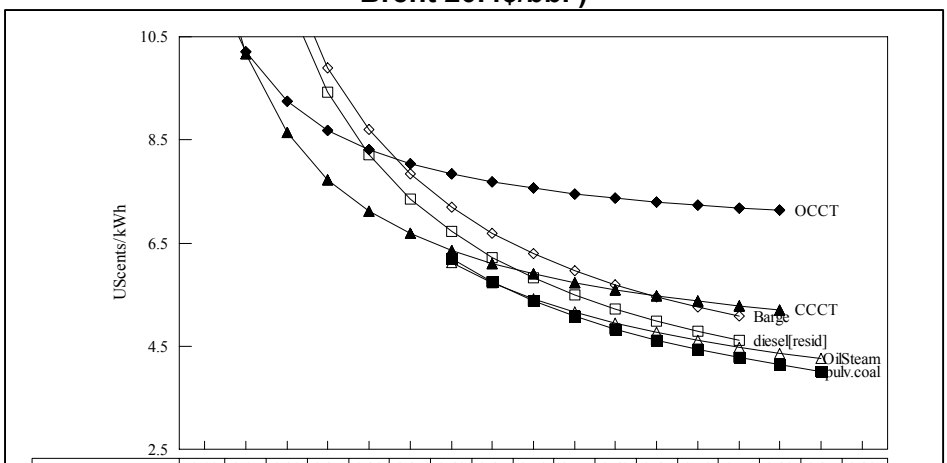
63 This is the assumption used by ECNZ. However, if the emissions standards as proposed by the Central Environment Authority are actually implemented, the sulphur content of heavy fuel oil would need to be reduced to around 1.1%S (See Annex III for further details).

64 For example, the overnight capital cost of coal is taken as $1008/kW (as per Electrowatt-- see Table A1.5). This is adjusted to 1999 prices to yield $1071/kW. This is adjusted by 7% for the up-front-infrastructure penalty of 7% (see Box 1) to yield $1146/kW. Finally this is adjusted for the opportunity cost of capital to $1303.

Table A1.6: Revised input assumptions

		pulv. coal	*OCCT*	*CCCT*	*diesel [resid]*	*diesel [barge]*	*Oil steam*
input data							
total capacity	[MW]	300	105	300	150	300	300
capital cost	[$/kW]	1303	386	725	1332	1334	1063
life	[years]	30	20	30	25	25	25
fixed O&M	[$/kW/month]	0.56	0.36	0.28	0.92	0.92	0.48
variable O&M	[mills/kWh]	2.79	2.85	2.72	7.36	7.36	2.37
scheduled maintenance	[days]	40	30	30	30	30	30
forced outage rate	[ ]	0.03	0.08	0.08	0.15	0.15	0.06
heat rate, net	[KCal/kWh]	2293	3060	1890	1954	1954	2293
primary fuel		*coal*	*auto diesel*	*auto diesel*	*resid*	*furnace oil*	*imp. fueloil*
heat content	[KCal/kg]	6300	10550	10550	10300	10300	10300
fuel price, cif plantgate	[$/bbl]	0	28.1	28.1	11.6	15.3	15.8
	[$/ton]	49	212	212	78	103	106
	[$/mmBTU]	1.96	5.05	5.05	1.91	2.51	2.6
	[cents/GCal]	779	2006		756	997	1031
fixed charge factor	[ ]	0.11	0.12	0.11	0.11	0.11	0.11
annual capital cost	[$/kW/year]	138.2	45.3	76.9	146.7	147	117.1
fixed O&M/year	[$/kW/year]	6.7	4.3	3.4	11	11	5.7
total fixed cost	[$/kW/year]	145	49.6	80.2	157.8	158	122.9
fuel cost	[UScents/kWh]	1.79	6.14	3.79	1.48	1.95	2.36
variable O&M	[UScents/kWh]	0.28	0.29	0.27	0.74	0.74	0.24

Figure A1.1: Screening curve (Saudi Light 34 $18.5/bbl; Brent 20.4$/bbl)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ OCCT	12.09	10.20	9.26	8.69	8.31	8.04	7.84	7.68	7.56	7.45	7.37	7.29	7.23	7.18	7.13		
▲ CCCT	13.22	10.17	8.64	7.73	7.12	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
⊟ diesel[resid]	20.22	14.22	11.22	9.42	8.22	7.36	6.72	6.22	5.82	5.49	5.22	4.98	4.79	4.61			
◇ Barge	20.72	14.71	11.70	9.90	8.70	7.84	7.19	6.69	6.29	5.96	5.69	5.46	5.26	5.09			
△ OilSteam							6.11	5.72	5.41	5.15	4.94	4.76	4.61	4.47	4.36	4.25	

Coal is seen to be least cost for baseload duty, combined cycle for cycling duty (PLF 15-40%), and open cycle combustion turbines for thermal peaking. However, the advantage of coal over oil-steam is small, particularly in the range of 40-50% PLF. Indeed, when the analysis is repeated for the lower oil price of $16/bbl (Figure A1.2),[65] the differences between coal and oil-steam are smaller still.

The differences between technologies are further illuminated by looking at the lifetime cost differences between coal and the other alternatives for some constant PLF -- as shown in Table A1.7.

Table A1.7: Lifetime cost difference $US million (NPV at 10% over 30 years) for baseload duty at 75% PLF

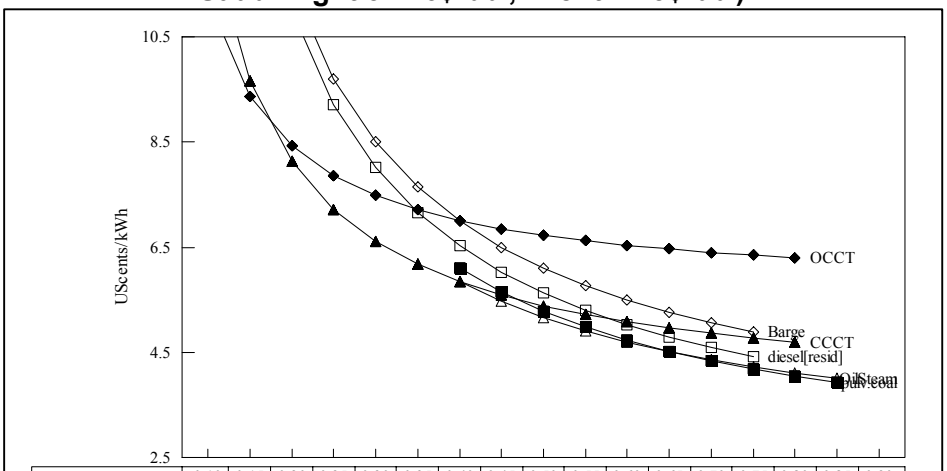
	$16/bbl		18.5$/bbl	
	NPV	Δ(coal)	NPV	Δ(coal)
Coal	776		794	
CCCT	886	110	982	188
diesel (residual)	821	45	857	64
diesel (furnace oil)	909	133	946	152
oil-steam	784	8	831	37

Clearly the most problematic assumptions are for capital costs. In cases where recent Sri Lankan prices have been revealed in international competitive bidding (such as for open cycle combustion turbines, or auto-diesel-fueled combined cycle plants) the basis is relatively firm; in others, such as for oil steam cycle plants (or LNG, discussed below), the estimates are subject to high uncertainty. Therefore the approach in such

[65] For Arab Light. This corresponds to years 2004-2009 of the 1999 World Bank oil price forecast.

cases has been to start with the coal plant (for which extensive site-specific costing studies have been conducted by CEB's consultants), and then assess the credibility of the other estimates through a comparative switching values analysis.

Figure A1.2: Screening curves: World Bank oil price forecast Saudi Light 34 16$/bbl; Brent 17.3$/bbl)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.11	5.65	5.28	4.98	4.73	4.52	4.33	4.18	4.04	3.92	
◆ OCCT	11.26	9.37	8.42	7.86	7.48	7.21	7.01	6.85	6.72	6.62	6.53	6.46	6.40	6.35	6.30		
▲ CCCT	12.71	9.66	8.13	7.21	6.60	6.17	5.84	5.58	5.38	5.21	5.08	4.96	4.86	4.77	4.69		
⊟ diesel[resid]	20.02	14.02	11.02	9.22	8.02	7.16	6.52	6.02	5.62	5.29	5.02	4.79	4.59	4.42			
◇ Barge	20.53	14.51	11.51	9.70	8.50	7.64	7.00	6.50	6.09	5.77	5.49	5.26	5.06	4.89			
△ OilSteam							5.85	5.46	5.15	4.90	4.68	4.51	4.35	4.22	4.10	4.00	

If, for example, the switching value of an alternative to coal requires a more than 86% decrease in capital cost from the baseline to be competitive - as in the case of auto-diesel fired combined cycle for baseload duty -- one may be reasonably sure that coal is least cost (other things equal); but if the alternative requires only an 11% decrease (as in the case of oil-cycle steam), then the assumptions for that alternative require further scrutiny. These switching values are shown in Table A1.8.[66]

Table A1.8: Capital cost switching values

	baseline estimate, $/kW	*switching value $/kW*	*reduction in baseline to attain switching value*
coal	1303		
CCCT	725	98	86.5%
diesel (residual)	1332	1127	15.4%
diesel (furnace oil)	1334	846	36.6%
oil-steam	1063	944	11.3%

The conclusion that steam-cycle is least-cost for baseload is at variance with the results of an IFC analysis that concluded that diesel-fired CCCT was least cost.[67]

[66] At the switching value, the life-cycle costs and unit electricity price are the same.

[67] IFC, *Sri Lanka, Review of Thermal Options*, 1999.

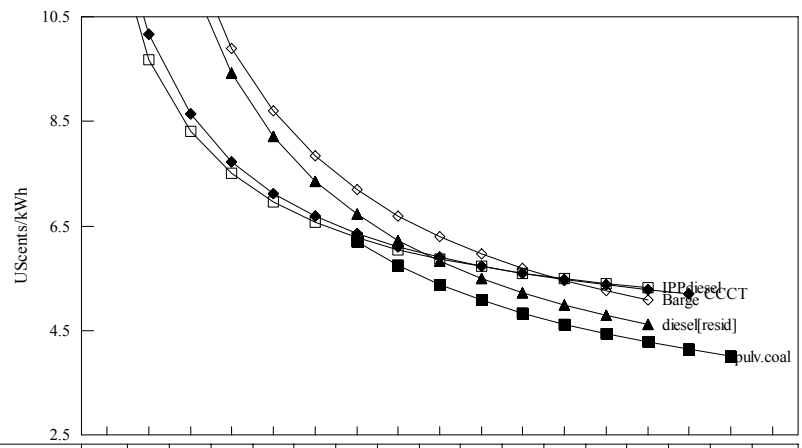
However, the main reason for this conclusion is IFC's approach to the treatment of up front infrastructure costs -- which are allocated entirely to the first unit, without any consideration of the economies of scale achievable with any subsequent units – that with already present infrastructure have very much lower costs. Clearly a 150 MW coal unit with capital costs of $1,500/kW will never be economic compared to CCCT.

A1.8 Small diesels

Over the past few years a number of small diesel IPP plants running on diesel oil have been built in Sri Lanka.[68] Unlike diesels using residual fuels or heavy fueloil (such as those at Sapugaskanda), such units have significantly lower capital costs -- but correspondingly higher fuel costs.

Figure A1.3 shows the screening curve for small diesels (compared to options suited to intermediate and baseload), in which we assume a capital cost of $600/kW. It is evident that at such capital costs, such plants are uneconomic for baseload operation, but are similar to CCCTs for load factors of less than 40%.

Figure A1.3: Screening curves for small diesels



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ CCCT	13.22	10.17	8.64	7.73	7.12	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ diesel[resid]	20.22	14.22	11.22	9.42	8.22	7.36	6.72	6.22	5.82	5.49	5.22	4.98	4.79	4.61			
⊟ IPPdiesel	12.41	9.68	8.32	7.50	6.96	6.57	6.28	6.05	5.87	5.72	5.59	5.49	5.40	5.32			
◇ Barge	20.72	14.71	11.70	9.90	8.70	7.84	7.19	6.69	6.29	5.96	5.69	5.46	5.26	5.09			
△																	

10% discount rate; 18.5$/bbl Arab Light price

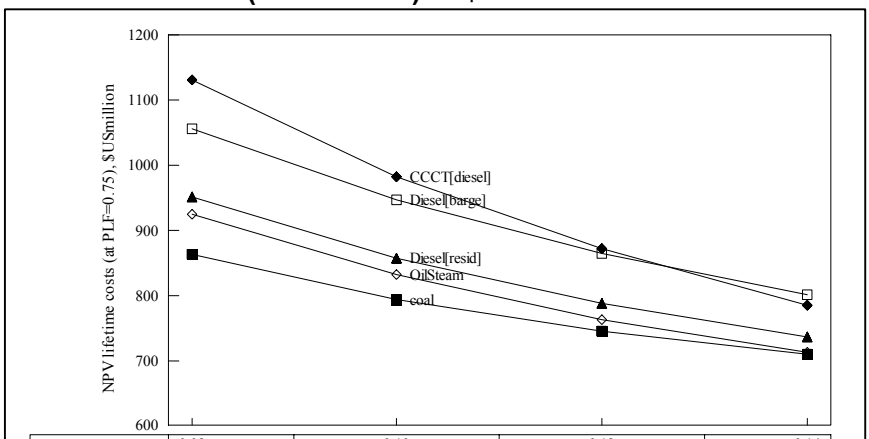
A1.9 Impact of the discount rate

The above analysis uses a 10% discount rate to reflect the opportunity cost of capital (or social discount rate SDR). Since generation technologies vary in capital intensity, the results may be sensitive to the rate assumed. In Figure A1.4 we show the lifetime costs for a range of discount rates from 8 to 14%. Technology rankings do not

[68] Such as the 22.5 MW Lakdanavi and 50.8 MW AsiaPower projects.

change until one moves from 12 to 14%. At 14%, the advantage of coal is very small indeed.[69]

Figure A1.4: Sensitivity to discount rate: lifetime NPVs (at 75% PLF) in $US million



discount rate	0.08	0.10	0.12	0.14
■ coal	862	794	745	710
◆ CCCT[diesel]	1130	982	871	785
▲ Diesel[resid]	950	857	788	736
⊟ Diesel[barge]	1055	946	864	801
◇ OilSteam	925	831	763	713

World oil price: 18.5$/bbl for Arab Light

A1.10 The impact of delay

In terms of NPV of lifetime costs, the differences between some technologies (e.g. between coal and oil steam cycle plants for equivalent baseload duty a range of $8 - 37 million)[70] are seen to be relatively small. Equally important, these differences are also relatively small compared to the cost of delay. Suppose, for example, a one-year delay in making a commitment to a 300 MW baseload plant, and that the power lost (1,971 GWh assuming 75% PLF) has to be generated in thermal peaking units. Suppose further that the alternative generation capacity has a shorter gestation time, and could be advanced from its least cost commissioning date by one year. Then the impact of delay is the difference in fuel cost between generating this 1,971 GWh in the coal plant, versus having to generate this power with diesel oil in either OCCT or CCCT plants, *less* the saving attributable to deferring the capital costs of the coal plant by one year, *plus* the cost of advancing the alternative by one year.[71] As indicated in Table A1.9, this is in the range of $24-$60 million (in NPV terms).

Table A1.9: Impact of delay

	pulv.coal	*OCCT*	*CCCT*

[69] The question of the sensitivity of coal v. oil steam cycle plants to the discount rate, and its relationship to whether such a baseload project is in the public or private sectors, is examined further in Annex VI.

[70] As shown in Table A1.7

[71] The difference between an outlay of λ, n years hence, to an outlay of λ today, is $\lambda-\lambda/(1+r)^n$ where r is the discount rate.

capital cost	[$US million]	411	116	217
Capacity	[MW]	300	300	300
PLF	[ ]	0.75	0.75	0.75
replacement generation	[GWh/year]	1971	1971	1971
fuel cost	[UScents/kWh]	1.79	6.14	3.79
annual fuel cost	[$US million]	35.2	121	74.7
delta(coal)	[$US million]		85.8	39.5
capital cost impacts				
delay coal by 1 year	[$US million]		-35.5	-35.5
advance alternative by 1 year	[$US million]		10.5	19.8
total impact	[$US million]		60.7	23.7
advance alternative by 3 years	[$US million]		28.8	54.1
total impact	[$US million]		79	58

However, this assumes that the adjustment required is to advance the alternative by one year. If that alternative (with shorter gestation time) must be advanced by more than one year (relative to the least-cost expansion plan), then the impact is correspondingly greater: if the advance time is 3 years, the total impact of delay rises to $58-79 million,[72] significantly above the difference between lifetime NPVs of coal and oil-steam ($8-37 million).

Nevertheless, this is not true of *all* technology comparisons. The lifetime cost difference between an auto-diesel fueled CCCT and a steam-cycle plant lies in the range of $110-188 million -- which is above the cost of a one to two-year delay.

A1.11 Conclusions

Several conclusions may be drawn from this analysis:

1. The most significant uncertainty in this analysis is capital cost. In the present highly competitive international power generation equipment market, capital costs for all power generation plant have fallen dramatically over the past few years (though particularly for combustion turbines). Nevertheless, the switching values analysis for capital costs shows that for baseload duty, only oil-steam running on heavy fueloil, or diesel using residual oil, are in the competitive range with coal. Since additional quantities of residual oil from

[72] If, at worst, adjustment of the construction schedule is not possible, and the output is lost (as for example occurred in 1996 during the drought, when as a consequence of delays in decisions there was inadequate thermal capacity in the system), then if the value of unserved energy is 10 cents/kWh, the value of the lost output rises $197 million. The cost of the 1996 power crisis has been attributed largely to the failure to implement the thermal capacity additions called for by the expansion plans of the early 1990s (see Lanka International Forum on Sustainable Development, *Linkages Between Economic Policies and the Environment in Sri Lanka*, December 1998). This report estimated the economic costs of the power crisis at around $73 million (including $50 million spent on emergency generator sets, and $23 million in loss of manufacturing GDP).

the Sapugaskanda refinery would only be available if the refinery were expanded, large scale use of such diesels is not feasible for the time being. Therefore we may say that:

- For baseload duty, the steam cycle - - be it oil or coal -- is least-cost. This is not unexpected given that Sri Lanka does not benefit from low cost domestic gas (which often changes the economics in favor of combined cycle plants even for baseload).[73]
- For cycling duty with load factors in the 20-50% range, combined cycle plants using auto-diesel (or naphtha, as discussed below) are least-cost.
- For thermal peaking, open cycle combustion turbines using auto-diesel are least cost.

2. Clearly oil-cycle steam plants, as an alternative to coal, merit more detailed analysis, which is presented in Annex III. However, the differences are likely to be small, and do not justify any delay in making a commitment to the needed additional baseload capacity.
3. It has been the practice of CEB (and its consultants Electrowatt) to compare the coal plant against an auto-diesel fueled CCCT to justify the former in economic analysis: the CCCT is claimed to be the "next best" option. This assumption is unjustified. Our results show that the second best option for baseload is steam-cycle oil.[74]
4. The error introduced by averaging infrastructure costs over multiple units appears to be small. Only if a site is *not* developed to its full potential as assumed in the calculation of the averaged cost of the first unit, is the effect significant. Nevertheless, for future WASP studies, we recommend adjustment of capital cost inputs to account for this effect, estimated at 1.07 in the case of the 3x300 MW West Coast coal project.
5. We have noted a number of inconsistencies in assumptions in the various studies conducted to date, although it does not appear that this has resulted in conclusions that are substantively different to those obtained by us in this report. Nevertheless, we recommend that future analyses adopt these more consistent assumptions.

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[73] And as we shall see in Annex IV, importing LNG does not change this conclusion.

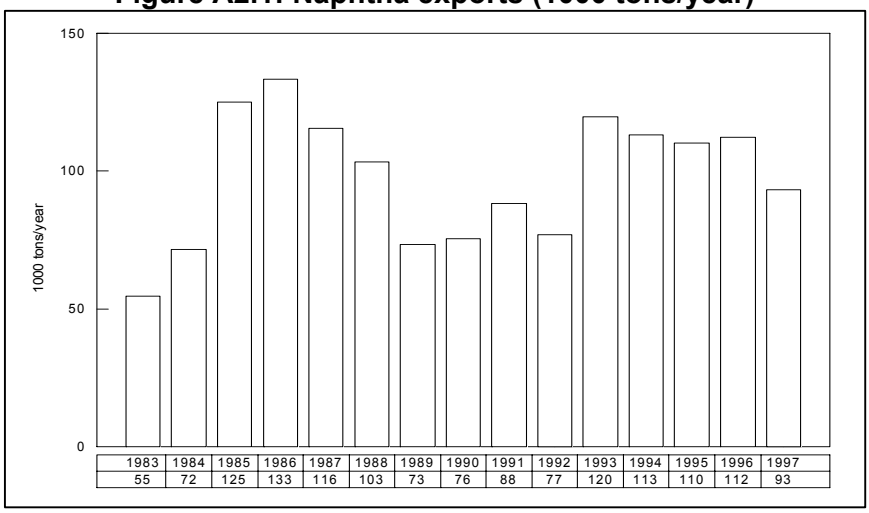
[74] See e.g. Electrowatt, *Economic and Financial Analysis: Coal-fired Thermal Development Project, West Coast*, 10/12/1997; pg. 1.

Annex II: Other Fuels for Combined Cycle Plants

A2.1 Naphtha

Because of the mismatch between domestic demand and the product mix of the Sapugaskanda refinery,[75] Sri Lanka has long produced a surplus of naphtha which has been exported to the Singapore spot markets. As indicated in Figure A2.1, these exports are generally in excess of 100,000 tons/year, and CPC expects that it could supply around 120,000 tons of naphtha/year for domestic power sector use.[76]

Figure A2.1: Naphtha exports (1000 tons/year)



Source: CPC Statistical Review 1983-1992, and 1991-1997

Clearly from a national economic point of view, at a time when large quantities of auto-diesel are being imported, it makes little sense to export naphtha if this could be used in place of auto-diesel as a fuel for CCCTs. In the past there have been concerns about some of naphtha's disadvantages (such as its low lubricity) and general lack of operating experience using naphtha in power combustion turbines,[77] but the evidence

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75 Between 1990 and 1997, gasoline consumption increased from 181,000 tons/yr to 194,000 tons/yr (an average increase of 1%/year). However, over the same period, autodiesel consumption increased from 511,000 tons/yr to 1,294,000tons/yr, an average increase of 14%.

76 See Feasibility Study, *Kelanitissa Combined Cycle Power Plant Project*, January 1996, Annex A-17.

77 For example, the 1996 Electrowatt Thermal Options study states that

Whilst most major gas turbine manufacturers offer units suitably modified to burn naphtha, actual operating experience is very limited. In the few cases where sites have utilised naphtha as a fuel this has normally been only as a standby fuel. Consequently there is currently no long-term experience of

from India, where several large naphtha-based projects have been commissioned over the past few years, now running satisfactorily, should help dispel these doubts.[78]

The economic price of using naphtha for power generation needs careful consideration, and should be based on the relevant opportunity costs. This is CPC's actual fob export price, adjusted for the *differential* between handling cost of moving the naphtha for shipment from refinery to port plus loading costs, and the cost of moving the naphtha by pipeline to a domestic power generation site. Thus the economic cost follows as:

Singapore (Gulf) spot price

- \- transportation costs (at $1.2/bbl)
- = CPC's FOB export price
- \- local transportation (from refinery to port) and handling costs (adjusted by the standard correction factor)
- \+ local transportation and handling costs (from refinery to power plant (adjusted by the SCF).
- = economic cost of naphtha for power generation.

The differential local costs -- at least in the case of the Kelanitissa CCCT -- are likely to be minimal, and may be ignored. However, the transportation costs to other plant sites may be more significant.

Historically, naphtha has been consistently cheaper than diesel on a $/bbl basis in both Gulf and Singapore markets, though the differential narrowed in 1998 during the period of highly depressed world oil prices (see Figure A2.2).

However, comparing volume based prices for products of different densities may be misleading. The density of chemical naphtha is 9.28 bbls/ton, whereas for autodiesel it is 7.52 bbls/ton.[79] When converted to a $/mmBTU basis (Figure A2.3), the differences are seen to be more variable, and indeed naphtha was more expensive than diesel during most of 1997 and 1998. Table A2.1 shows the annual averages.

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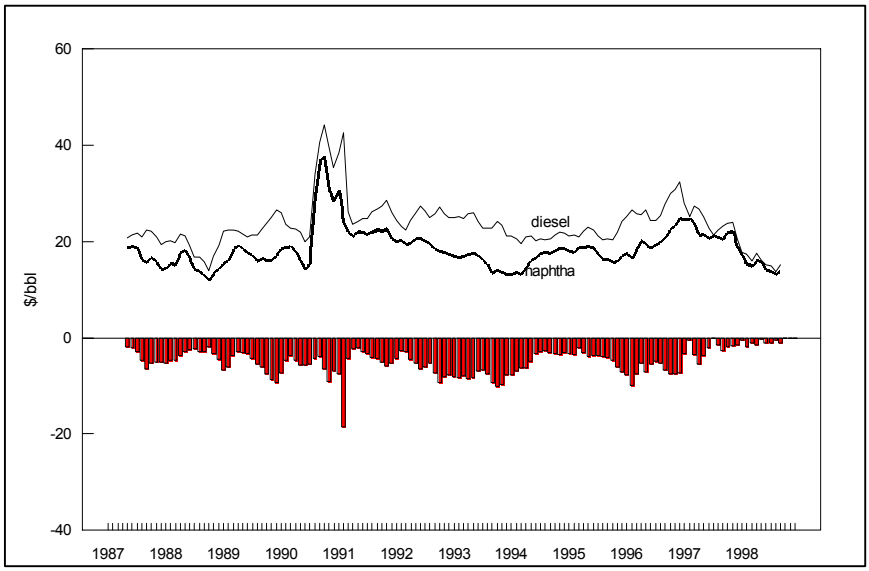
using naphtha in the larger, higher rated gas turbines currently being installed. It is understood that the largest units currently in operation designed for burning naphtha, but only as a standby fuel, are eight Mitsubishi (Westinghouse) 701DA gas turbines each rated at 146 MW which form part of the 1,800 MW CCCT at Teeside, UK, commissioned in 1993. The gas turbines operated with up to 100% naphtha during periods when the normal supply of gas has been unavailable. (pg. 3-16).

[78] Naphtha has been successfully used in captive industrial projects as well as IPPs. For example, the GE/Nuovo Pignone turbines at the Arvind Mills projects in Naroda and Santej have been running continuously on naphtha for over a year. GE turbines at the 515 MW Essar IPP in Gujarat are also running on naphtha.

[79] All values of petroleum product densities used in this report are taken from CPC, *Statistical Review*, 1983-1992, page 29, as given for operating temperature (85 F for distillates, 90 F for fueloil). The mean average temperature in Colombo is 81 F.

Figure A2.2: Naphtha and diesel prices, Singapore spot market[80]



Source: Platt's Oilgram and Petroleum Intelligence Weekly

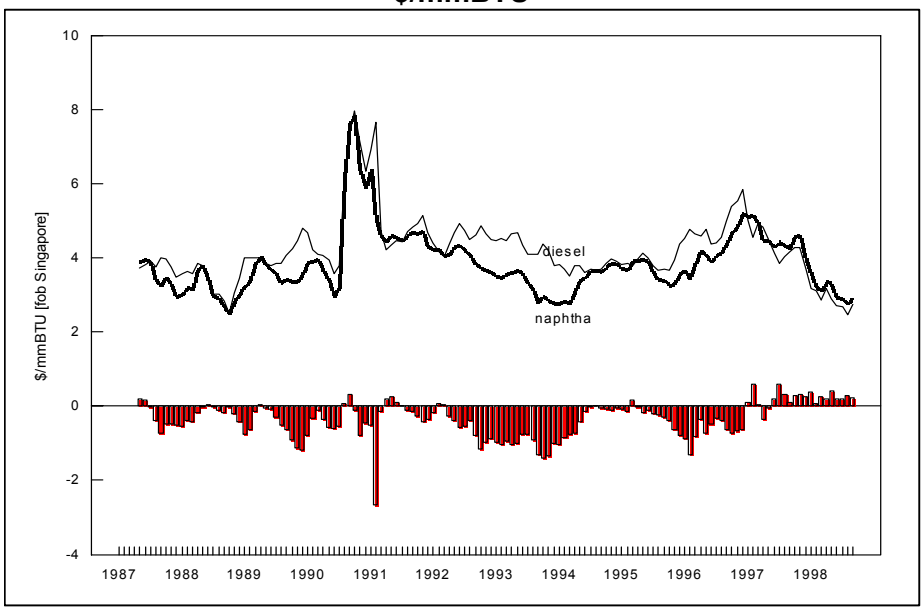
Table A2.1: Annual averages, naphtha v. diesel ($/mmBTU)

	naphtha	*diesel*	*differential: naphtha-diesel*
1987	3.5	3.80	-0.28
1988	3.1	3.31	-0.20
1989	3.5	4.08	-0.53
1990	4.9	5.27	-0.35
1991	4.7	5.08	-0.34
1992	4.0	4.53	-0.50
1993	3.2	4.31	-1.04
1994	3.4	3.75	-0.35
1995	3.6	3.89	-0.24
1996	4.2	4.86	-0.66
1997	4.5	4.35	0.20
1998	3.1	2.15	0.24

80 As shown in the Background Report, there is little historical difference between Gulf and Singapore naphtha prices (unlike the differential for heavy fueloil). Consequently we use the Singapore price as a basis.

81 All values of petroleum product densities used in this report are taken from CPC, *Statistical Review*, 1983-1992, page 29, as given for operating temperature (85 F for distillates, 90 F for fueloil). The mean average temperature in Colombo is 81 F.

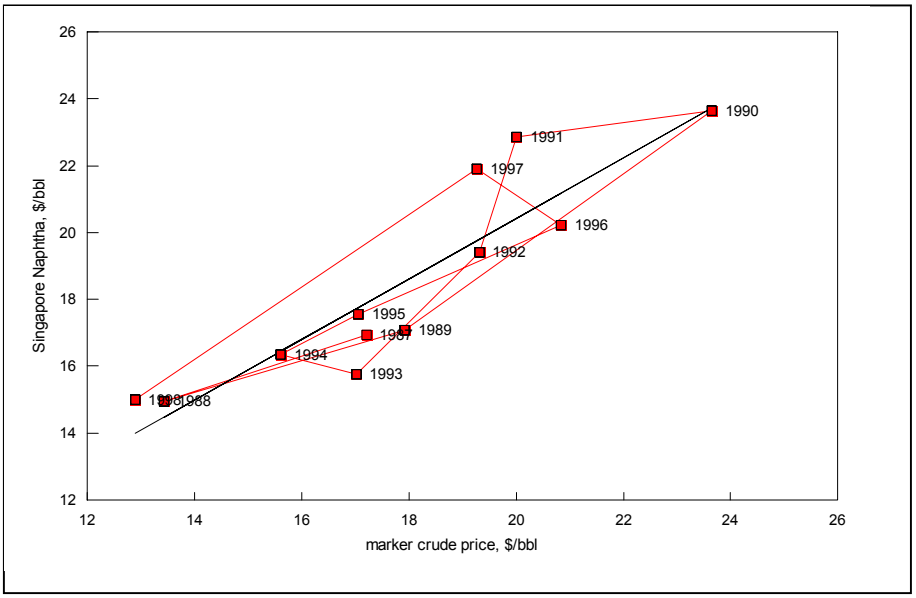
Figure A2.3: Singapore diesel and naphtha prices (FOB), $/mmBTU



The relationship between annual average Singapore naphtha prices and the annual average Brent crude price (Figure A2.4) is given by:

[Singapore naphtha price,$/bbl]=2.35 +0.9 [Brent crude price,$/bbl] :$R^2$=.81

Figure A2.4: Singapore naphtha price v. marker crude price



Source: Annual averages computed on the basis of monthly assessments in Platt's Oilgram and Petroleum Intelligence Weekly

With these assumptions we may examine the relative attractiveness of different fuels for CCCTs.[82] Figure A2.5 shows the screening curves for three cases (assumptions are listed in Table A2.2):

1. Auto-diesel (as proposed for the AES project)
2. Domestic naphtha (as proposed for the OECF funded project under construction at Kelanitissa)
3. Imported naphtha.

Table A2.2: Assumptions for CCCT screening curves

		diesel	*Domestic .naphtha*	*Imported .naphtha*
total capacity	[MW]	300		
overnight cost	[$/kW]	620		
Opportunity cost adjustment	[ ]	1.14		
nominal economic cost	[$/kW]	704		
infrastructure adjustment	[ ]	1.03		
capital cost	[$/kW]	725	725	725
Life	[years]	30	30	30
fixed O&M	[$/kW/month]	0.27	0.27	0.27
variable O&M	[mills/kWh]	2.72	2.72	2.72
scheduled maintenance	[days]	30	30	30
forced outage rate	[ ]	0.08	0.08	0.08
heat rate, net	[KCal/kWh]	1890	1890	1890
heat content	[KCal/kg]	10550	10800	10800
fuel price, cif plantgate	[$/bbl]	24.3	17	19.5
	[$/ton]	183	158	181
	[$/mmBTU]	4.37	3.69	4.23
	[cents/GCal]	1734	1463	1678
representative PLF	[ ]	0.75	0.75	0.75
fixed charge factor	[ ]	0.11	0.11	0.11
annual capital cost	[$/kW/year]	76.9	76.9	76.9
fixed O&M/year	[$/kW/year]	3.3	3.3	3.3
total fixed cost	[$/kW/year]	80.2	80.2	80.2

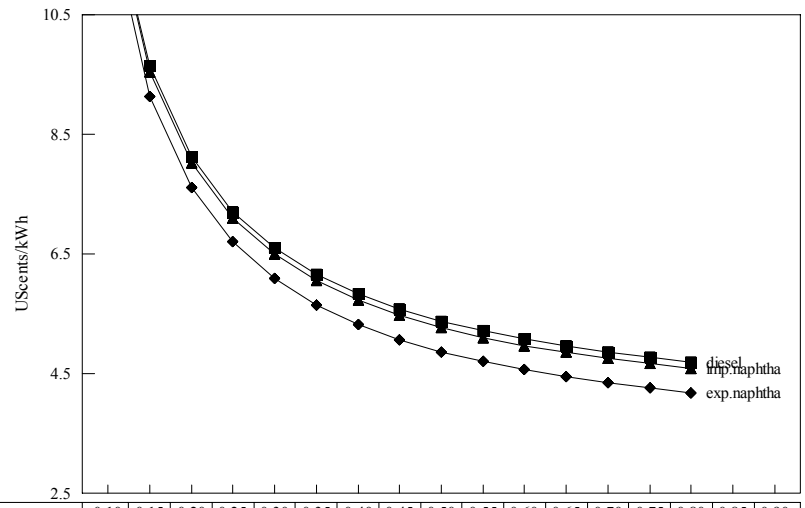
The screening curves reveal significant economic advantage to naphtha-based

[82] Again we find differences in basic assumptions between past studies. For example, the 1996 Electrowatt Thermal Options study, in Table 3.11 "Specification of Fuel Types Currently available in Sri Lanka", states the "gross calorific value" of naphtha at 11,200 KCal/kg. The OECF feasibility study for the Kelanitissa CCCT quotes the "low thermal value" as 10,800 KCal/kg. The CPC figures for "calorific value" are net (LHV) (CPC *Statistical Review*, 1983-1992), and are quoted as 10,783 KCal/kg for light naphtha and 10,716 KCal/kg for chemical naphtha.

This problem is made worse by the use of different units even within the same study. Again the 1996 Electrowatt Thermal Options Study is a good example. Table 3.11 (of the Electrowatt Report), as noted, uses KCal/kg. Table 3.5, which quotes details of CCCT performance, quotes Net (GCV) heat rates in "KJ/kWh" Table 5.1, "Summary of Principal Characteristics of Thermal Plant Options", shows calorific values in kCal/litre, and heat rates in kCal/kWh.

CCCTs over diesel if that naphtha would otherwise be exported; but if naphtha needs to be imported, the costs are roughly equal to that of auto-diesel fired projects.

Figure A2.5: Screening curves for CCCTs



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ diesel	12.70	9.65	8.12	7.21	6.60	6.16	5.84	5.58	5.38	5.21	5.07	4.96	4.86	4.77	4.69		
◆ exp.naphtha	12.19	9.14	7.61	6.70	6.09	5.65	5.32	5.07	4.87	4.70	4.56	4.44	4.34	4.26	4.18		
▲ imp.naphtha	12.59	9.54	8.02	7.10	6.49	6.06	5.73	5.48	5.27	5.11	4.97	4.85	4.75	4.66	4.59		

World oil price: Arab Light $15/bbl

The corresponding lifetime costs are shown in Table A2.3. We show the results for 75% PLF for comparison with the results for baseload options of Annex I, as well as for the more likely 40% PLF for combined cycle plants. The saving for domestic naphtha ($51 million) is about 9% of the corresponding total lifetime cost using auto-diesel.

Table A2.3: Lifetime costs (NPV @10% discount rate, $US million)

	75% PLF			*40% PLF*		
	cents/ kWh	*NPV*	*Δ(auto-diesel)*	*cents/ kWh*	*NPV*	*Δ(auto-diesel)*
coal		776				
CCCT: auto-diesel	4.77	886		5.84	579	
CCCT: domestic naphtha	4.26	791	-95	5.32	528	-51
CCCT: imported naphtha	4.66	300	-20	5.73	568	-11

World oil price: Arab Light $16/bbl.

The decision to use domestic naphtha for the OECF 150 MW CCCT plant currently planned for Kelanitissa (supplied by pipeline from the Sapugaskanda refinery) is confirmed by these results. Although the 1999 CEB expansion plan, correctly, treats this project as a committed plant, this plant is chosen for 2001 even in a completely unconstrained model simulation (as discussed in Section 4, above).

There is concern that this might lead to a requirement for *importing* naphtha. But this appears to be the consequence of assumptions in the economic analysis of the feasibility study,[83] which states that

> *" . . . the project will require about 150,000-200,000 tons/year of naphtha because it will be operated as baseload at an extremely high load factor according to the supply demand balance after 1999. Therefore it will be necessary to import about 30,000- 80,000 tons/naphtha"*[84]

This conclusion appeared to be the basis for rejecting naphtha as a potential fuel for the subsequent CCCT being proposed for Kerawalapitiya.[85]

Yet CEB studies that take actual dispatch into account show that Kelanitissa would in fact be operated mainly for cycling duty, with a maximum expected value of fuel consumption of 121,000 tons in 2001. Consumption after 2003 never exceeds 62,000 tons, and falls to the range of 11,000 to 20,000 tons/year (Figure A2.6).[86]

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83 The use of unrealistically high (and constant) plant load factors in the economic analysis of detailed feasibility studies is common practice, for it tends to increase the economic rate of return (ERR). At the same time, however, these same studies also tend to underestimate the benefits of the incremental power produced, which are typically valued at the average tariff. Particularly in the case of peaking plants, however, the willingness to pay (which is the proper measure of economic benefit that should be used) is likely to be substantially higher. These may of course offset each other, but it would still be better if more rigorous assumptions were applied.

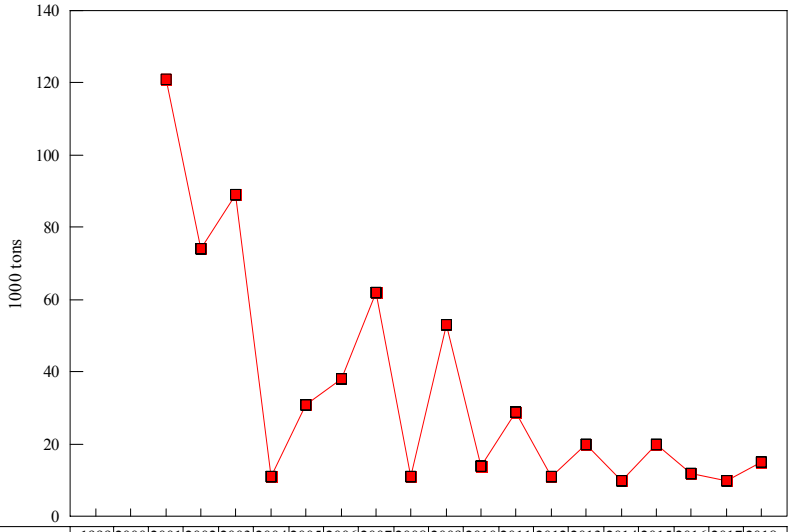
84 OECF, *The Kelanitissa Combined Cycle Power Plant Project*, Final report, Part I, January 1996.

85 Tokyo Electric Power Services Co. Ltd, *Feasibility Study on Combined Cycle Power Development Project at Kerawalapitiya,* January 1999; pg. 4-2-3.

> *It is generally impossible to start up a gas turbine with naphtha fuel ... Furthermore, because naphtha is different from such fuel like diesel oil as it quantity in circulation in the world is numerous, some countermeasures for back-up shall be prepared. But CPC has no remaining power for feeding naphtha for the project, therefore there is no way to cope with such occasion as its feeding is stopped for some causes. . . . As mentioned above, naphtha is not adequate for the project because this fuel involves many big problems.*

86 See 1999 CEB Generation Plan, Annex 4.4

Figure A2.6: Projections of the average CEB naphtha requirement for Kelanitissa CCCT



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1000 tons/year			121	74	89	11	31	38	62	11	53	14	29	11	20	10	20	12	10	15

This Figure shows that once the coal plant is in operation, CCCT operation is limited to intermediate and peaking duty. Consequently, beyond 2005 there may well be scope for further naphtha-fueled CCCTs using domestic naphtha, in the event that the expansion plan requires additional cycling units.

Table A2.4 shows monthly naphtha consumption for the drought hydro condition in the CEB 1998 base case scenario: this corresponds roughly to the 1 in 10 year condition (and is one of five hydro conditions considered by WASP). Under these circumstances the CCCT would be running at maximum availability for six to eight months a year, under which circumstances naphtha would certainly need to be imported. However, the need for imports is certainly no *greater* than if fueled by diesel.

It may be concluded that any requirement for CCCTs beyond the OCEF/Kelanitissa project should also be naphtha fired. To be sure, in drought years, naphtha would have to be imported, but if the CCCT is diesel-fueled, then imports would have to occur in *all* years.[87] The fact that naphtha would need to be imported in some years (or even in every year) is no argument against naphtha; but certainly having to *export* naphtha (while importing diesel) results in an economic loss of about 23$/ton.

[87] The pipeline from the refinery to the harbour normally used for naphtha exports has often been used also for diesel imports over the past few years as the volume of diesel imports has risen. CPC is of the view that importing naphtha -- were that to be necessary -- poses neither technical problems nor economic costs.

Table A2.4: Monthly naphtha consumption at Kelanitissa, drought hydro conditions

	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Total*
													1000 tpy
2002	7048	14081	14081	14081	7048	14081	14081	14081	14081	14081	14081	14081	**155**
2003	9397	14081	14081	14081	9397	14081	9397	14081	14081	14081	14081	14081	**155**
2004	14081	13801	14011	9355	14081	9369	9369	14081	825	14067	14081	1077	**128**
2005	14081	14025	14081	9383	14081	9383	9383	14081	5146	14081	14081	7747	**140**
2006	14081	9397	14081	14081	14081	9397	9397	14081	7537	14081	14081	10152	**144**
2007	14081	9397	14081	14081	14081	9397	9397	14081	14081	14081	14081	14081	**155**
2008	14081	8600	12962	11718	14081	7761	14081	8795	951	13731	13410	811	**121**
2009	14081	10236	13899	11368	14081	10264	14081	10250	8907	14067	14081	11270	**147**
2010	14053	14053	8404	5509	14067	2839	14067	4642	1049	3873	9201	965	**93**
2011	14081	14081	9620	8781	14081	9187	14081	9117	1426	12403	13508	1538	**122**
2012	13242	12683	1692	643	13186	13186	13074	4642	1091	657	741	993	**76**

A2.2 Residual Oil

Despite the low capital costs of CCCT, auto-diesel is an expensive fuel for power generation, and in Sri Lanka, CCCT is indicated for intermediate duty only. However, if residual oil could be used as a fuel, then in principle, CCCT technology may well be competitive for baseload duty as well.

Actual field experience with this fuel is however still quite limited: the Kot Addu plant in Pakistan has the longest operational experience with combustion turbines fueled by residual oil of any plant in the world.[88]

There exist a range of problems related to fuel quality. Deposits on turbine blades gradually turbine output. Turbines must be shut down about every 120 hours for a detergent and water washing of exhaust stages -- which take about 10 hours as the blades must be cooled before cleaning. O&M costs are about three times those of operation in natural gas or diesel fuel. The sodium and vanadium in the fuel has to be washed out before use.

A 1994 assessment by IFC concluded that

> *operation of combustion turbines on residual fuel oil is a demanding technique and the benefits of low capital cost are offset by high O&M costs, reduced availability, and reduced fuel efficiency. Our policy of requesting sponsors of new plants to obtain a solid long-term O&M agreement with the turbine manufacturer is clearly appropriate.*[89]

[88] Kot Addu has four 110MW units from Siemens, four 100MW GEC-Alsthom units (GE 9E design), and two Fiat (Westinghouse design) 100MW. Two of the Siemens units were installed in 1986 and have 30,700 actual operational hours each, mostly on residual fuel; two GE units installed in 1987 have operational 24,500 hours, again mostly on residual fuel.

[89] P. Nickson, *Technical Note: Combustion Turbines Fueled by Residual Oils*, IFC, October 28, 1994.

A more recent assessment by the World Bank is slightly more optimistic, based upon the experience of the 220MW Valladolid power plant in Mexico, which has some 24,000 hours of operating experience since 1994 using heavily contaminated fueloil containing up to 95 ppm sodium and potassium, and up to 300 ppm of vanadium.[90] This plant has had good experience using Epsom Salts (magnesium sulfate) dissolved in water and injected into the gas turbine combustor, where it combines with the vanadium to produce a water-soluble salt that causes only minor blade corrosion, and removed by washing at 150-hour intervals.

IFC's 1999 analysis makes the assumptions as shown in Table A2.5 for operating parameters for CCCTs using diesel and residual fuel:[91]

Table A2.5: Operating assumptions for CCCT

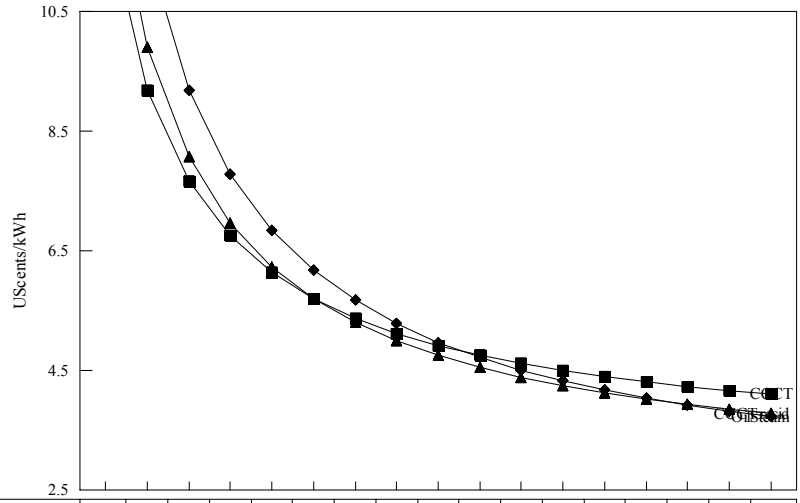
	Diesel	*Residual*	*Ratio resid:diesel*
plant life, years	20	18	0.9
useful capacity	150	135	0.9
installed capital cost	550	575	1.5
plant factor	0.9	0.7	0.8
fixed O&M, $/kW/year	30	50	1.7
variable op.cost, $/kWh	0.003	0.009	3.0
heat rate, Btu/kWh	7100	7700	1.1

When these assumptions are used in our screening curve model, we obtain the results shown in Figure A2.7. It is evident that in the intermediate duty range, residual fired CCCT would have a small advantage over diesel fuel, but at high PLF oil steam is marginally less costly. However, it is evident that the cost differences are quite small given the high risk of operating problems.

[90] R. Taud, J. Karg and D. O'Leary, *Gas Turbine Based Power Plants: Technology and Market Status*, World Bank, Energy Issues, No.20, June 1999, Washington DC.

[91] IFC, *Sri Lanka, Review of Thermal Options*, 1999.

Figure A2.7: Screening curves for residual oil-fired CCCT, $14.5/bbl Brent



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ CCCT	12.25	9.19	7.67	6.75	6.14	5.70	5.38	5.12	4.92	4.75	4.61	4.50	4.40	4.31	4.23	4.16	4.10
◆ OilSteam	16.19	11.52	9.18	7.78	6.84	6.17	5.67	5.28	4.97	4.72	4.50	4.32	4.17	4.04	3.92	3.82	3.72
▲ CCCT:resid	13.59	9.91	8.07	6.96	6.23	5.70	5.31	5.00	4.76	4.56	4.39	4.25	4.13	4.02	3.93	3.85	3.78

Annex III: Steam Cycle Oil

A3.1 Past studies

Serious consideration of oil steam-cycle plants for Sri Lanka appears to be quite recent. The 1999 CEB generation planning study is the first time that this option has been included by CEB, though one recent detailed project feasibility studies for combined cycle plants prepared by CEB's consultants has used oil steam-cycle plants burning heavy fueloil for comparison of economics.[92] Moreover, as we have already noted, the assumptions used by CEB in the 1999 Generation Plan are such that it is not surprising that steam-cycle oil plants are not selected by CEB's modeling studies.

The 1996 thermal options study justified exclusion of steam cycle oil plant on grounds of "relatively high fuel cost."[93] Columns [1] and [2] of Table A3.1 summarises the analysis provided in that study: however, even when differential port costs are taken into account, oil is only some 5% more expensive, which is hard to reconcile with "relatively high fuel cost."

Table A3.1 : Levelised lifetime cost, UScents/kWh

	Coal [1]	*Furnace Oil [2]*	*Residual Oil [3]*
Capital	2.04	1.80	1.80
Fuel	1.81	2.72	2.16
Total	3.85	4.52	3.96
incremental port cost (30$/kW for coal)	0.45		
Total	4.30	4.52	3.96
		+5.1%	-8%

Source: Columns [1] and [2]: Electrowatt, *Thermal Generation Options Study*, *op.cit.*, pg. 4-10

Column [3]: our estimate (based upon the residual oil prices shown in the thermal options report).

The thermal generation options study assumes imported furnace oil as the fuel on grounds that the existing refinery can supply only a maximum of 375,000 tpy of residual

[92] See e.g. Tokyo Electric Power Services Co. Ltd., Feasibility Study on Combined Cycle Power Development Project at Kerawalapitiya, January 1999.

[93] Thermal Generation Options study, op.cit, pg. 4-10.

(for which it assumes diesel generation would be the preferred use).[94] Nevertheless, it may be noted that the economic value of residual oil is considerably lower than that of furnace oil even using the assumptions of the Thermal Options Study (taken as 0.086 $/litre as opposed to .106 $/litre); and were this fuel available, it has an *advantage* of 8% over coal, as shown in column [3] of Table A3.1.[95]

Despite these negative views, it is worth noting that a 1995 argued for steam cycle oil plants in Sri Lanka.[96] Though the focus was on GHG emission reductions, it was concluded that at the then prevailing prices,[97] use of oil rather than coal might also be justified on economic grounds:[98]

> *perhaps the most significant finding relates to the potential replacement of coal plants by steam-cycle oil plants. To date these have not been considered by CEB . . . and at present levels of oil prices, even provide economic benefits as well as GHG emission reductions.*[99]

Certainly given the results of Annex I, oil steam-cycle plants appear to warrant closer examination. Tables A3.2 and A3.3 summarise capital cost and heat rate assumptions for oil-steam plants. The Background Report discusses in detail the ECNZ proposal for a 222 MW oil-fired project.

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94 According to CEB, this has since fallen to 250,000 tons/year.

95 The Electrowatt figure for the capital cost differential between new oil-steam and coal plants -- a ratio of 0.82 -- is on the high side compared to other estimates: a World Bank Study of the Philippines suggests a value of around .75, while European data suggest a value of 0.72 (As reviewed in M. Bernstein, *Costs and Greenhouse Gas Emissions of Energy Supply and Use*, World Bank Environment Department, 1994; expressed in 1991$, the baseline figures are 1052 $/kW for oil-steam, 1458 $/kW for coal, pg. 44.) Moreover, most sources suggest that the efficiency of oil-steam plants would be higher, not lower as suggested by the Electrowatt study. According to the thermal options study, Table 5.1, the furnace oil fired steam plant has a lower efficiency (.354) than the coal plant (.361). The European data reviewed by Bernstein, *op.cit.*, suggests a net heat rate of 2,300KCal/kWh (37%) for coal, but only 2,260 KCal/kWh (38%) for oil -- i.e. oil has a higher efficiency.

96 P. Meier and Mohan Munasinghe, *Greenhouse Gas Emission Reduction: a Case Study of Sri Lanka*, Energy Journal, 16, 4, pg. 79-107.

97 In 1994 and 1995 the average prices of Brent were $15.5 and $17/bbl, respectively.

98 The more recent Global Overlay study also identifies oil-steam+FGD using residual oil (potentially available from any expansion of the Sapugaskanda refinery) as a win-win option (i.e. bringing both GHG emission reduction and economic benefits relative to a baseline "reform case" based on CEB's 1998 generation plan. Use of imported heavy fueloil, again with FGD, is also win-win (though with less obvious economic gains). See Meier and Munasinghe, *GHG Overlay Study*, *op.cit.*, Table 4.10.

99 *Ibid.*, pg.105

Table A3.2: Capital cost estimates for oil steam cycle

	$/kW	*Fixed O&M $/kW/year*	*Variable O&M UScents/kWh*
ECNZ, 222 MW total cost (see Annex V of Background Report)	882	26[(1)]	0.129
ECNZ, 222 MW excluding soft costs (see Annex V of Background Report)	638		
Electrowatt Thermal Options Study: excluding site costs:unit size:			
300MW	664	6.5	.298
700MW	526	5.2	.239
World Bank, Philippines study (1000 MW site size)	800	104	.14
Tokyo Electric Power (used for comparison with diesel-based CCGT at Kerawalapitiya): 750 MW site size	1039	9.13	0.417
ElectroWatt, 3 x 300 MW, "site independent costs", 1995.	665	6.5	.298

(1) Quoted by ECNZ as $6.5million/year

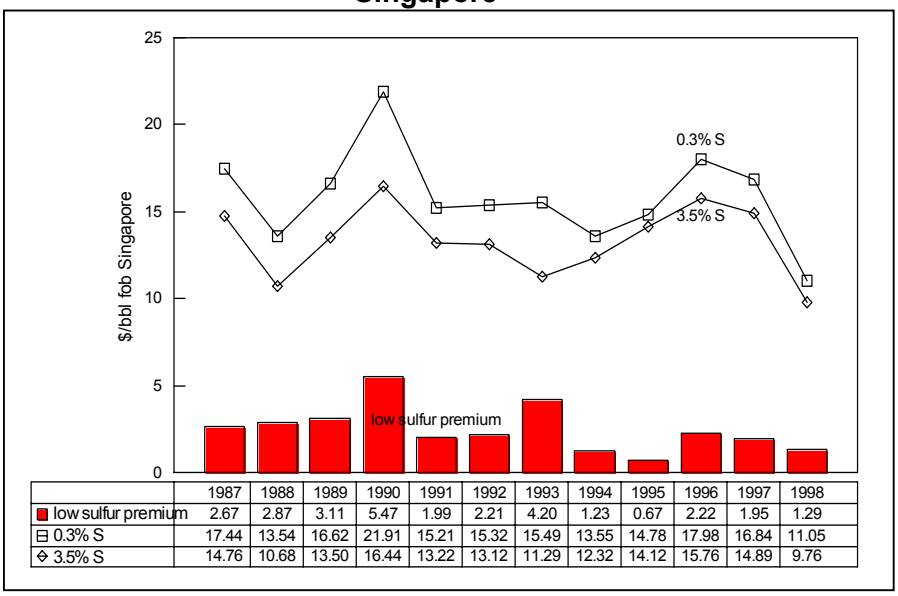
Table A3.3: Heat rate assumptions

	KCal/kWh	*Efficiency*	
ECNZ	2435	35.3%	average, used in economic analysis(quoted at 10,196 KJ/kWh)
Electrowatt	2430	35.4%	average, used in economic analysis
Tokyo Electric Power	2269	37.9%	as used in economic analysis
ECNZ	2435	35.3%	full load(222MW net), cited as 10,500 KJ/KWh
	2511	34.2%	part-load(132 MW net), cited as 11,029 KJ/kWh
	2944	29.2%	Minimum-load(85 MW net), cited as 12,327KJ/kWh
Electrowatt Thermal Options Study	2430	35.4%	full load

A3.2 The sulfur issue

As noted previously, heavy fueloil sells at a significant discount to the crude price. However, the price of heavy fueloil is strongly influenced by its sulfur content. As shown in Figure A3.1, the difference between 0.3% and 3.5% sulfur fueloil has varied considerably between a high of 5.47$/bbl in 1990 to as little as 0.65$/bbl in 1995.

Figure A3.1: 3.5% and 0.3% sulfur fueloil prices, $/bbl FOB Singapore

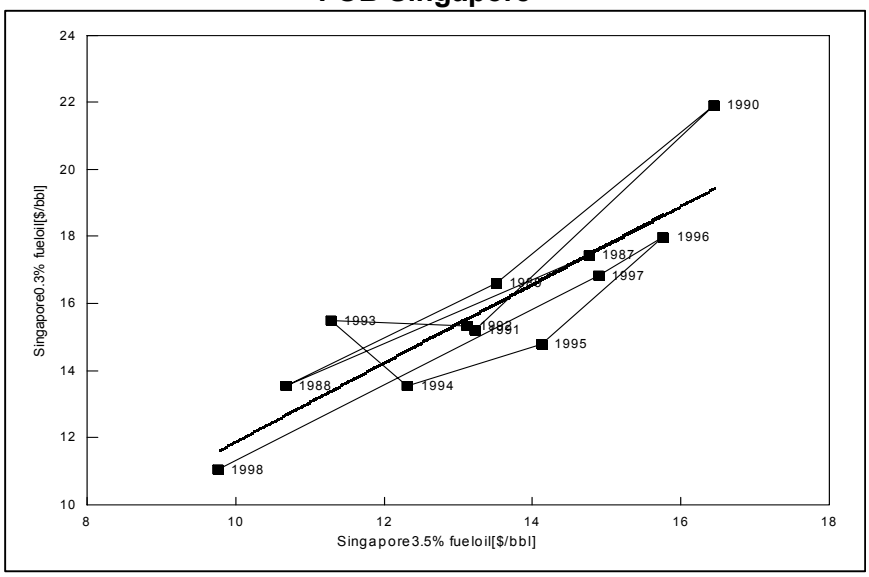


	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
low sulfur premium	2.67	2.87	3.11	5.47	1.99	2.21	4.20	1.23	0.67	2.22	1.95	1.29
0.3% S	17.44	13.54	16.62	21.91	15.21	15.32	15.49	13.55	14.78	17.98	16.84	11.05
3.5% S	14.76	10.68	13.50	16.44	13.22	13.12	11.29	12.32	14.12	15.76	14.89	9.76

The relationship between high and low sulfur fuel oils on an average annual basis (Figure A3.2) is given by

$$0.3\%S[\$/bbl] = 0.196 + 1.172\ [3.5\%S,\$/bbl];\ R^2=0.78$$

Figure A3.2: 3.5% and 0.3% sulfur fueloil prices, $/bbl FOB Singapore



Use of low cost HSFO (3.5% sulfur) in a steam cycle oil plant results in SOx emissions that are considerably higher than the corresponding emissions from a coal plant, and do not meet the proposed SOx emission standard. Therefore, the plant must either be fitted with flue gas desulfurisation (FGD), or fueloil of a lower sulfur content must be used. The so-called seawater process is the indicated technology, which takes

advantage of sea water's natural alkalinity to absorb SOx.[100] Table A3.4 shows sulfur emission calculations for pulverised coal, CCCT and Oil steam.

Table A3.4: Sulfur emission calculations for oil steam

		pulv.coal	*CCCT*	*OilSteam*
total capacity	[MW]	300	300	300
representative PLF	[ ]	0.75	0.75	0.75
annual generation:gross	[GWh]	1971	1971	1971
UScents/kWh@representativePLF	[UScents/kWh]	4.43	5.37	4.67
delta[cost]	[UScents/kWh]		0.94	0.24
heat rate, net	[KCal/kWh]	2293	1890	2293
heat content	[KCal/kg]	6300	10550	10300
fuel consumption	[1000tons/yr]	717	353	439
primary fuel		*i:coalLoS*	*autodiesel*	*impFO*
SOx emissions				
sulfur content of fuel	[ ]	0.50%	0.50%	1.12%
fraction oxidised	[ ]	0.98	1	1
removal %	[ ]	0	0	0
SOx emissions	[KgSOx/kWh]	0	0	0.01
annual SOx emisisons	[tons/year]	7030	3531	9822
Sri Lanka emission standard	[mg/MJ]	520	340	520
	lbsSO2/mmbtu	1.21	0.79	1.21
calculated emissions	[mg/MJ]	372	227	520
	[gms/sec]	297	149	415
Maximum Sulfur %	[ ]	0.70%	0.75%	1.12%
or removal %	[ ]			
frac of FGD@90 %				0
frac.0.3 % Sfueloil	[ ]			

A3.3 Switching values analysis for steam-cycle oil plant

Switching values for capital costs of oil steam-cycle plants will be dependent upon a variety of assumptions including the world oil price, the discount rate, and assumptions about the sulfur content of the fuel necessary to meet ambient SOx standards. Table A3.5 shows the capital cost switching values for a broad range of oil prices from 10-13$/bbl (that reflects the 1998 low, and average 1998 conditions) to $21/bbl (that reflects current conditions). The assumption here is that fueloil will be blended to meet the proposed sulfur emission standard (520 mg/MJ).

[100] There is experience with this technology elsewhere in South Asia. Tata Electric Company's Trombay Unit 5 has had a pilot plant FGD system (treating 25% of the flue gas, equivalent to 125 MW) operating since 1988. The size of this system is to be doubled as part of the IBRD's assistance to Tata Electric Companies under loan LN-3239-IN. For further description, see World Bank,Staff Appraisal Report, *Private Power Utilities (TEC) Project*, Report 8610-IN, Asia Country Department IV, June 6, 1990 (pg. 53).

Table A3.5: Switching values for steam-cycle oil plants

		oil plant capital cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
baseline estimates			
coal	1303		
oil cycle steam	1063		
Switching values for oil-cycle steam at:			
10$/bbl	1245	17%	0.96
13$/bbl	1126	6%	0.86
16$/bbl	1007	-5%	0.77
18.5$/bbl	908	-15%	0.7
21$/bbl	809	-24%	0.62

Oil price is for Arab Light; fueloil blended to 1.1% sulfur

Alternatively we may examine the lifecycle costs, as shown in Table A3.6. This shows that the economic consequence of choosing *oil* rather than coal is a *benefit* of $20 million if the (Arab light) oil price (averaged over the lifetime of the plant) is $13/bbl, but a loss of $79 million if the oil price (average) is 21$/bbl. Based on the consensus forecasts for a probable average oil price over the next decade of 15-20$/bbl, coal is seen to have an advantage (if the capital cost of the plant is at the Electrowatt estimate). When the capital cost falls to the switching value -- say $908 at 18.5$/bbl (in Table A3.5) -- then the lifetime costs are the same.

Table A3.6: Life-cycle costs, NPV ($US million)

oil price, $/bbl	*coal*	*oil*	*consequences of the choice of oil*
10	734	677	57
13	755	735	20
16	776	794	-18
18.5	794	842	-48
21	811	891	-79

10% discount rate; 75% PLF; Oil prices for Arab Light

These results assume that fuel-oil blended to 1.12% sulfur would be used, such that the proposed emission standard for SOx from oil plants (520 mg/MJ) could be met. However, whether emissions at this level would also satisfy the ambient air quality standard is unclear. In the case of the proposed coal plant, whose emissions are 341 mg/MJ, the Environmental Impact Assessment shows that FGD is not required to meet ambient standards when low-sulfur coal is used.[101] In order to be sure of compliance, an

[101] The Environmental impact statement also looks at a "worst case" coal of 0.7%S and lower heat content of 6,050 KCal/kg: this just meets the proposed standard.

oil plant may therefore require SOx emissions that are no higher than those of the corresponding coal plant. This would again require either an FGD system, or the use of a fueloil blended to 0.8% S. The detailed analysis of the Marsden B project suggests that blending is more cost-effective than FGD, so we assume here the blended fuel option.[102]

The corresponding switching values for this worst case for heavy oil are indicated in Table A3.7. For 18.5$/bbl, the switching value falls from 908$/kW to 886$/kW -- in other words, if more expensive lower sulfur oil must be used, the capital cost will need to fall further to remain competitive with coal. Nevertheless, capital costs in the range of 887-988$/kW (for $16-18.5/bbl) imply that these are between 76 to 68% of the capital cost of coal -- which seem only slightly lower than values assumed elsewhere (such as the 75% used in the recent World Bank study of generating options in the Philippines).

Table A3.7: Capital cost switching values for steam oil cycle plants, fueloil blended to 0.8 %S.

		oil plant capital cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
baseline estimates			
coal	1303		
oil cycle steam	1063		
switching values for oil-cycle steam at:			
10$/bbl	1232	16%	0.95
13$/bbl	1110	4%	0.85
16$/bbl	988	-7%	0.76
18.5$/bbl	886	-17%	0.68
21$/bbl	785	-26%	0.6

The corresponding life-cycle impacts are shown in Table A3.8. The costs of choosing oil rather than coal in the 16-18.5$/bbl range increase from $18 - 48 million (Table A3.6) to $24-55 million.

Table A3.8: Lifecycle costs, NPV ($US million)

oil price, $/bbl	*coal*	*oil*	*consequences of the choice of oil*
10	734	681	53
13	755	740	15
16	776	800	-24
18.5	794	849	-55
21	811	898	-87

10% discount rate; 75% PLF; Oil prices for Arab Light

[102] See Background Report, Annex II.

These results are for a discount rate of 10%. Since oil plant is less capital-intensive than coal, it follows that higher discount rates would favor oil. Indeed, the weighted cost of capital in IPPs is likely to be higher than the 10% that may be appropriate for public sector projects.[103] Moreover, in an IPP financing, soft costs (financing and legal fees, development fees, IDC, etc.)[104] add at least 25% to the baseline cost - which will therefore again be higher for coal than for oil. Thus, in Table A3.9, we show the corresponding results for private financing at 12% discount rate. As expected, the switching values of capital cost are closer to those of coal than those previously indicated: for example, at $18.5/bbl, the capital cost of the oil plant would need to be only 79% of the coal plant cost, as opposed to 70% at 10% discount rate.

Table A3.9: Capital cost switching values for steam oil cycle plants, with fueloil blended to 1.1%S and 12% discount rate

		Oil Plant Capital Cost	
	$/kW	*difference to Electrowatt baseline estimate*	*as fraction of coal plant capital cost*
baseline estimates			
coal	1671		
oil cycle steam	1363		
switching values for oil-cycle steam at:			
10$/bbl	1618	19%	0.97
13$/bbl	1516	11%	0.91
16$/bbl	1413	4%	0.85
18.5$/bbl	1327	-3%	0.79
21$/bbl	1241	-9%	0.74

Baseline estimate for coal = $1303/kW x 1.28 soft-cost multiplier for IPPs;
for oil = $1063/kW x 1.28 = $1329/kW.

The lifecycle costs (Table A3.10) -- assuming the 1363 $/kW capital cost -- now show a benefit of $15 million at $16/bbl, versus a *cost* of $11million at $18.5/bbl.

[103] For example, if the debt/equity ratio is 70/30, foreign debt is priced at LIBOR+3% (say 6% + 3% = 9%), and the equity return is 15%, then the weighted cost of capital is 10.8% (or 12.3% if the equity return is 20%). However, see Annex VI for a more rigorous definition of effective cost of capital to Sri Lanka in the case of foreign financed IPPs.

[104] Since in a foreign financed IPP the bulk of these charges are likely to be in foreign currency, these constitute real economic costs to Sri Lanka. The 1.25 soft cost multiplier assumed here is conservative -- many Indian IPP projects (even those competitively bid) have higher values.

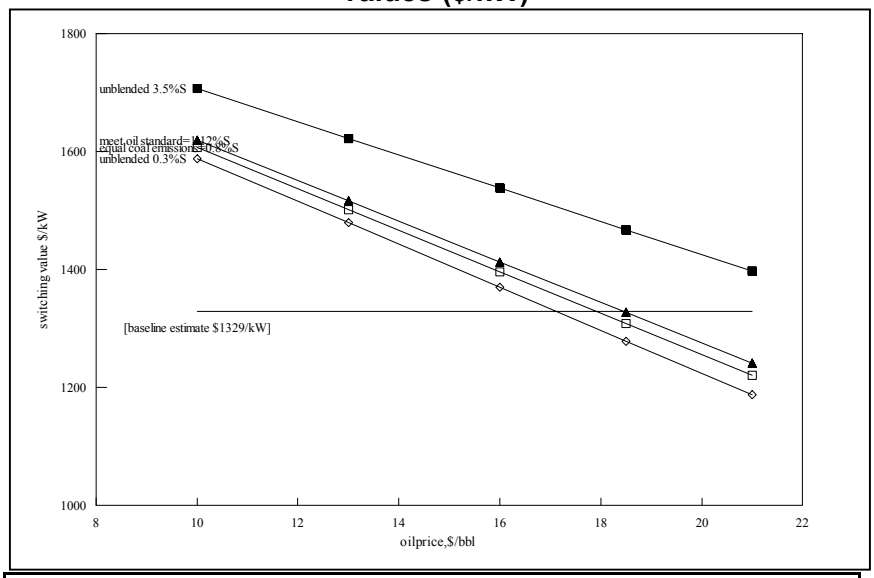
Table A3.10: Lifecycle costs, NPV ($US million), 1.1%S

	coal	*oil*	*consequences of the choice of oil*
10$/bbl	794	716	79
13$/bbl	812	765	47
16$/bbl	830	815	15
18.5$/bbl	845	857	-11
21$/bbl	860	898	-38

12% discount rate; 75% PLF; Oil prices for Arab Light

The complete sensitivity for switching values as a function of both oil price *and* sulfur content is shown in Figure A3.3. This figure is to be interpreted as follows: for any capital cost that is lower than the curve (for a given level of sulfur), oil will be cheaper than coal. For example, at $16/bbl, and 3.5%Sulfur oil, the switching value is $1,538/kW (as opposed to the baseline cost of 1,363$/kW); this means that any capital cost lower than $1,538/kW makes oil cheaper.

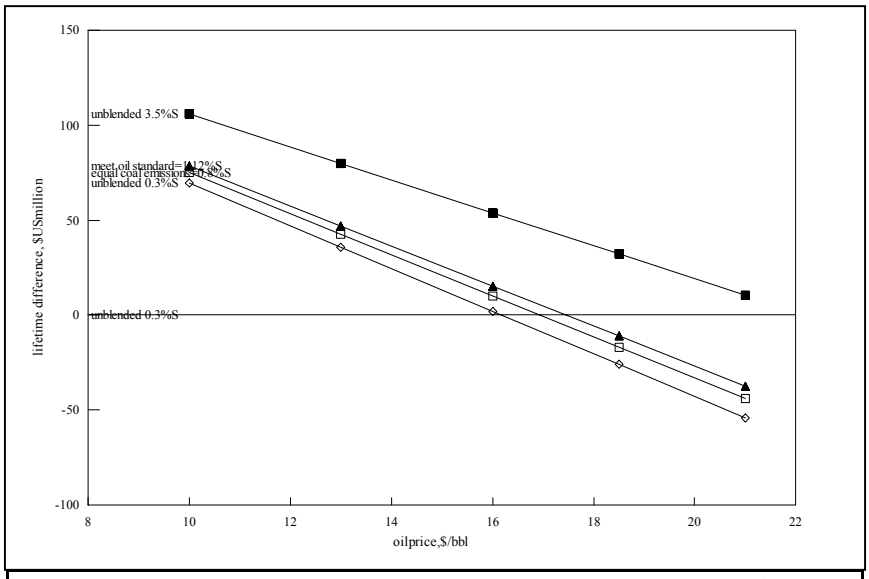
Figure A3.3: Sensitivity analysis for oil capital cost switching values ($/kW)



	oil price (Arab Light), $/bbl				
	10	*13*	*16*	*18.5*	*21*
unblended fuel 3.50%S	1707	1622	**1538**	1467	1397
blended to meet oil standard (340 mg/MJ)=1.1%S	1618	1516	1413	1327	1241
blended to meet same emissions as coal plant (171 mg/MJ)=0.8%S	1607	1501	1396	1308	1220
unblended fuel 0.30% S	1588	1479	1370	1279	1188

assumptions: 12% discount rate, 75%PLF

Figure A3.4: Benefits of oil steam-cycle versus coal, $US million at baseline estimate of $1363



	oil price (Arab Light), $/bbl				
	10	*13*	*16*	*18.5*	*21*
unblended fuel 3.50%S	106	80	54	32	10
blended to meet coal standard (520 mg/MJ)=2.49%S					
blended to meet oil standard (340 mg/MJ)=1.63%S	79	47	15	-11	-38
blended to meet same emissions as coal plant (171 mg/MJ)=0.82%S	75	43	10	-17	-44
Unblended fuel 0.30%S	69	36	2	-26	-54

Now suppose that the ratio of oil to coal capital cost is not 80%, but 75% (the assumption of the Philippines study) -- with a baseline oil capital cost estimate of $1,253. Then the benefits (and costs) of oil work out as indicated in Table A3.11. Under such assumptions, if the presently proposed sulfur standard for oil is to be met, oil is cheaper at any cost lower than about 19.5$/bbl (and brings a benefit of $23million if the Arab light oil price is at $18.5/bbl (Brent at around $20/bbl).

Table A3.11: Benefits of oil steam-cycle versus coal, $US million at baseline estimate of $1,253/kW

	oil price (Arab Light), $/bbl				
	10	13	16	18.5	21
unblended fuel 3.50%S	140	114	88	66	44
øblended to meet oil standard (340 mg/MJ)=1.63%S	113	81	49	23	-4
blended to meet same emissions as coal plant (171 mg/MJ)=0.82%S	109	76	44	17	-10
unblended fuel 0.30%S	103	70	36	8	-20

12% discount rate, 75%PLF

A3.4 Conclusions regarding oil v. coal steam cycle

These results permit several important conclusions

- Whether imported heavy fuel-oil or coal steam cycle is least cost depends critically upon assumptions. Small changes in assumptions may switch the least-cost choice.
- Thus it cannot be ruled out that in a competitive bid in which the choice of fuel/technology were left to the bidder, that coal would necessarily win -- though it would appear somewhat unlikely if the fuel price risk is assigned to the seller. Nevertheless, there may be scope for optimisation and hedging techniques that would be within the competence and experience of an international IPP which may make oil more attractive to a private owner.
- If the fuel price risk is taken by the buyer, then comparison of bids across different fuels and technologies would involve a risk evaluation, in which the higher fuel price risk associated with oil needs to be traded-off, quantitatively (and transparently) against the lower capital cost. Such a risk assessment (and related questions of benefit sharing, structuring and quantifying the corresponding criteria for evaluation of proposals, etc.) falls outside the scope of the present study, but should certainly be undertaken before one could consider an RFP that leaves technology and fuel choice to the IPP.
- The results suggest that duel-fuel capability may be advantageous - since when oil prices are low (as they were for much of 1998), a dual-fuel capable plant would almost certainly use heavy fueloil rather than coal.
- The concept of *multi*-fuel capable plants also merits some further examination, particularly since the GHG overlay study suggests co-firing of wood (at a low volume ratio) from dendro-thermal plantations as one of the potentially more attractive GHG mitigation measures). However, more detailed analysis of this option was beyond the scope of the present report.

Annex IV: LNG[105]

There is no question that from an environmental point of view, LNG is an attractive option when compared to coal or oil-based plants.[107] Moreover, LNG has the advantage that it is readily burnt in combustion turbines (with or without a combined cycle) that are characterised by high efficiency and which have seen significant recent decreases in capital costs.[108] But whether in the case of Sri Lanka these advantages offset the disadvantages -- notably the very high cost of LNG -- is unclear.

A4.1 The Asian LNG market

In 1997, the Asian market for LNG was about 54 million tons, with Japan by far the largest consumer. While Asian producers have dominated this trade in the past, the 1977 commissioned Adgas plant in Abu Dhabi was the only middle east exporter for almost 20 years, until the Qatar project came on-stream in 1997. In the past most of the Gulf region's gas was simply flared, but with 35% of the worlds gas reserves, a number of new LNG projects are now in progress. There is clearly scope for significant expansion of LNG supply in the region, provided the world oil price -- to which that of LNG is tied -- does not stray for too long below 15$/bbl. The first LNG supply to South Asia is likely to be a 1.6 mtpy flow from Oman to Maharashtra for ENRON's Dabhol project, for which contracts were signed in December 1998.[109]

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105 The public discussion in Sri Lanka about LNG (as gauged by Newspaper articles) has been quite uninformed, and information on LNG available to the CEB generation planning department has been limited to that provided by ENRON. For this reason this section contains more extensive background information.

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107 For example, among fossil fuels, natural gas has the lowest emissions of GHG emissions per unit of generation (15.2 tons C per TJ as compared to 25.8 for coal and 21.1 for heavy fueloil).

108 A comparison of the 1996 and 1998 generation plan assumptions is instructive. In 1996 the capital costs of open cycle gas turbines were estimated at 514$/kW (CEB, 1996); in 1998, this had dropped to 372$/kW (CEB, 1998), an assumption documented by the actual price of a 105 MW unit commissioned in 1997. Nevertheless it is worth noting that in 1988, the Thermal Options study (by Black and Veatch, *op.cit.*), estimated capital costs of a 300 MW coal plant at around $1,600/kW, which a decade later had fallen to $1,451 (for the first unit of the Puttalam project), equal to about $1,000/kW in 1988 prices, a decrease of 40% in real terms. Both estimates include the cost of coal jetties.

109 As reported by Financial Times Asia Gas Report, January 1999.

LNG is under active consideration for a number of coastal sites in India (see Box 2), most of which include a substantial power generation component. Note the scale of these proposals: none is less than 2 million tons per year (mtpy). A 2.0 mtpy project, which if devoted entirely to power generation, would correspond to about 2,400 MW of CCCT capacity (if run at 65% PLF). LNG shipping terminals and regasification facilities are subject to large scale economies, and 2 mtpy seems to the be minimum size for favorable project economics.

Box 2: Proposed LNG projects in India

The power crisis in India has led to the construction of a large number of CCCTs which will use naphtha initially, and gas later on once additional gas supplies are injected into the domestic pipeline system (particularly into the HBJ pipeline from Hazira in Gujarat to Delhi). As of May 1998, there were 19 such gas/naphtha projects based on CCCTs, of which 5 are partly or fully operational -- Jegurupadu (GVK, 235 MW), Kakinada (Spectrum-NTPC, 208 MW) and Vijeswaram (APGPCL, 172 MW) in Andhra Pradesh; and Paguthan (Torrent, 655 MW) and Hazira (Essar Power, 515 MW) in Gujarat.

However, with limited domestic gas resources, other options for augmenting supplies are under consideration. A number of proposals for bringing gas to India from Turkmenistan, Iran and even Oman, by overland pipeline, have been floated. These necessarily have to cross Pakistan territory to reach India. However, given the present geo-political realities in Central Asia, such proposals are quite unlikely to materialise in the short to medium term. Gas imports by pipeline from Bangladesh are another option, but even here the likely time frame is long. Given these realities, the only other option for increasing gas supplies is imported LNG, and LNG imports benefit from the lowest rate of duty on imported fuels. A number of major projects have been proposed, as indicated in the table below

Company	Site	Capacity,mtpy
Petronet LNG	Dahej, Gujarat	5
Petronet LNG	Cochin, Kerala	2.5
TIDCO	Ennore, Tamil Nadu	5
Shell	Hazira, Gujarat	2.5
Enron	Dabhol, Maharahstra	5
British Gas	Piparvar, Gujarat	2.5
Reliance, Elf	Hazira,Gujarat	5
Reliance	Jamnagar, Gujarat	5
ISPAT	Kakinada, A.P.	2
Finolex	Mangalore, Karnataka	?
Total, HPCL	Kakinada, A.P.	2

The fate of many of these projects is linked to the new GoI policy on "mega-power" projects. Progress in others has also been slowed by NTPC's efforts to acquire an equity share in the Petronet projects, given that NTPC is a major potential customer for the gas and its desire to get gas at the cheapest possible price.

How many of these projects will actually be built in the foreseeable future is unclear.[110] ENRON's Dabhol project, near Bombay, is the one that is most advanced (Box 3), but many of the others are suffering the usual delays. Long-term contracts with credit-worthy buyers are required to finance the huge upstream investments -- a problem that has yet to be resolved in most of the proposed Indian deals given that most Indian State Electricity Boards are insolvent.[111]

However, for a small developing country like Sri Lanka, with no gas resources of its own,[112] and which lies at least 800 miles from potential LNG supply sources,[113] LNG is likely to be an expensive option.[114] The fact that interest in Indian LNG projects is so high does not transfer to Sri Lanka: India has power shortages that are of an altogether

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[110] If all these projects were to come to fruition, India's LNG imports would amount to almost 40 mtpy, which would make India second only to Japan among importing countries. However, how many of these proposals are bankable remains untested: some observers doubt if more than two or three of these will actually be implemented over the next decade. For example, in November 1997, World Gas Intelligence assessed the situation as follows: "...most analysts agree that one out of the 10 or more proposals to build LNG import terminals might materialise by 2005, and two by 2010, with a combined capacity of 7.5 to 10 mtpy."

[111] Only the first seven so-called "fast track" projects will benefit from Central counter-guarantees (including the first phase of ENRON's Dabhol project). Other projects typically require guarantees from State Governments, letters of credit and escrow arrangements. But since the escrow capacity of most SEBs is limited, some State Governments are now considering pledging part of their state sales tax receipts. Such a proposal has been floated by the Government of Tamil Nadu for the proposed Ennore LNG power project.

[112] And therefore lacking an existing gas distribution system into which gas not used for power generation could be fed.

[113] To the west, the Persian Gulf lies about 1700 miles from Colombo; to the East, potential sources in Indonesia or Malaysia are about 800 miles distant.

[114] Some advocates of LNG use in Sri Lanka argue (or imply) that LNG would be used just temporarily, and would be replaced by pipeline gas from the huge reserves in Central Asia at a later stage. For example, articles in Daily News (J. Ratnasiri, *Natural gas, An alternative to Coal*, Daily News, December 24, 1997; J. Ratnasiri, *A New Dimension in Power Generation Planning*, Daily News, December 15, 1997) talk about trans-Asian gas pipelines, and cite the Qatar-Bombay ($5 billion), Iran-Calcutta ($13 billion), and Turkmenistan-Pakistan ($2.5 billion) pipelines as examples of "countries that are investing large sums of money despite the fact that they have their own gas fields". The reader of such words would naturally believe that these projects were underway. The facts are that these are all still proposals, which is hardly surprising given the geo-political situation in Central Asia. Perhaps the rebellions, wars and border disputes in Tajikistan, Afghanistan and Kashmir may be eventually settled, with concomitant benefits to regional harmony and security, but such speculation seems a very poor basis for planning Sri Lanka's energy supply sources.

The only money spent to date has been for feasibility studies and lobbying. For example, the American UNOCAL and Saudi Arabian Delta oil companies assembled a consortium in the mid 1990s to plan, build and manage a proposed $1.9 billion, 1,492 km, 20 bcmy Central Asian Gas Pipeline to bring gas from Turkmenistan through Afghanistan into Pakistan. Various MOUs and agreements were signed. Nevertheless, by March 1998 UNOCAL announced that the project was unfinancable under current conditions, which seems unsurprising given the continued military conflicts in Afghanistan. For details of the role of UNOCAL/Delta in shaping American policy toward the Taliban (embraced by UNOCAL at least after their early successes as a force for stability in Afghanistan) see e.g. R. Mackenzie, *The United States and the Taliban*, in W. Maley, Ed. Fundamentalism Reborn: Afghanistan and the Taliban, Hurst&Company, London, 1998, pg. 90-103.

different magnitude, so the large scale of LNG projects offers the potential for a rapid closing the demand-supply gap. However, even in India, this will come at a high price, for LNG cannot compete with plants fueled by Indian domestic coal.[115]

Box 3: ENRON's Dabhol project [116]

ENRON's combined cycle Dabhol project consists of two stages. Stage I, 826 MW, started operation in April 1999. It uses naphtha and distillate fuel. Stage II, 1624 MW, will use LNG, and will include the LNG infrastructure (regasification facility, port & breakwater, LNG vessel). Stage II is expected to be commissioned by 2001. Power generation will require about 2 mpty of LNG.

ENRON has 50% of the equity of phase I, with GE and Bechtel with 10% each, and the Maharashtra State Electricity Board 30%. The debt:equity ratio is reported as 60:40, with a total cost of $1,076 billion. Of the $643 million debt, $150 million has been provided by a commercial bank syndicate led by Bank of America and ABN Amro. OPIC has provided $100 million, US EXIM Bank has provided $298 million guaranteed by a group of Indian financial institutions.

Phase I (but not Phase II) will benefit from a central government counter-guarantee, valid for 12 years, with a fixed ceiling of Rs15 billion/year subject to 9% annual escalation. In case of termination of the PPA, the guarantee is limited only to the outstanding foreign debt, and to $300 million.

Phase II, for which financial closure was reported in May 1999, will cost $1.87 billion, including $500 million for the LNG infrastructure. The debt portion is $1.414 billion, with $333 million in Rs financing with lead arranger IDBI at 15-16%. A $497 million syndicated loan (SBI, ABN Amro, CSFB, ANZIB, Citibank, Canara Bank, Bank of America, Development Bank of Singapore and Credit Lyonais) is priced at LIBOR plus 375 basis points (3.75%).[117] An export credit loan of $435 million (Japanese EXIM $258 and commercial banks $175 million, the latter insured by Japanese Ministry of International Trade and Industry) was priced at 5.85%, and a $91 million loan from the Belgian Export Credit agency OND was priced at 5.66%. ENRON is reported to hold 80% of the equity, with GE and Bechtel each 10%.

This is the largest non-recourse financing in India, and the largest foreign non-recourse financing without a Government of India guarantee. It is secured by Government of Maharashtra guarantee, letters of credit and an escrow arrangement.[118]

Mitsui was selected to provide the 135,000 m^3 LNG vessel, to be owned by a consortium of ENRON, Mitsui OSK lines and Shipping Corporation of India. The reported cost for this vessel is $209 million, resulting in a charter rate of $98,600/day for a ten-year period, based on a 30% return on equity.[119]

Even before ENRON's collapse in 2002, the Dabhol project descended into disarray in 2001, as the Maharashtra State Electricity Board (MSEB) declared its inability to pay the tariff. Lenders, equity holders, MSEB, the Maharashtra Government, and the Central Government (who provided counter-guarantees), have battled over the project's fate and attempted to find a buyer for the project itself. Attempts to sell the project's electricity to other State Electricity Boards (and the Power Trading Corporation) have largely failed (on the not unsurprising matter of the very high tariff!). Some potential buyers have expressed interest in the LNG terminal, but are unenthusiastic about the power generation project. The disputes have yet to be finally resolved.

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115 see e.g. Central Electricity Authority, *Techno-economic Appraisal of the 4x500MW Talcher Stage-II Project*, Ministry of Power, Delhi, January 1999.

116 This information has been compiled from a number of sources, including IPP Financings, Power Line, March 1999; ENRON, Power Line, January 1999; Dabhol Phase II, Power Line, May 1999; Sanjay Bhatnagar, *The Financing of Dabhol II,* Indian Infrastructure, June 1999.

117 While this appears to be competitive, up front fees reported to be as much as 2- 3% sweetened the deal for the commercial banks (Indian Infrastructure, *Biggest Deal of the Year*, June 1999).

118 The financing for Phase II was delayed by the imposition of sanctions by the US Government, so that US EXIM that participated in Phase I had to be replaced (by Japanese EXIM).

119 However, there are a number of recent reports that the downturn in the international LNG markets and the Asian financial crisis (particularly in South Korea) have resulted in new vessel rates being quoted by S. Korean and Japanese yards to around $160 million (see e.g. Gas Transport Charter Rates, Business Standard, August 26, 1999).

For these reasons, past studies of generating options for Sri Lanka have rejected this option -- although in most cases the economics of LNG projects do not appear to have been computed in any detail, a gap that we redress in this report. The 1995 Electrowatt Thermal Options study typifies the rationale for excluding LNG plants as viable options for Sri Lanka requiring detailed study:[120]

> *"..Sri Lanka has no discovered reserves of natural gas, the only way to supply Power Stations [with gas] would be by imports by ship of LNG. There are no existing port or storage facilities and the cost of construction of these facilities would probably make this option too expensive. It has therefore not been considered further . . . A major LNG facility for a medium sized combined cycle plant would represent more than 50% of the capital value of the power station. For the scale of operation and configuration in Sri Lanka the use of LNG or LPG is thus not considered an economic proposition in the foreseeable future."*

The recently completed feasibility study of a combined cycle power plant at Kerawalapitiya[121] comes to similar conclusions. In its evaluation of fuel supply, it considered LNG, LPG, naphtha, heavy diesel oil and auto-diesel oil. LNG was rejected for detailed analysis on grounds that

> *The LNG consumption of a 150 MW project is 0.1 mtpy, whereas quantity of LNG contract is generally more than several million tons per year . . the contract period is generally very long, for example 20-25 years, furthermore the consumer must keep the dealing conditions[sic] that they have to receive the final quantity of LNG in both month and yearly.*[122]

This study noted other significant obstacles, notably the difficulties of unloading LNG in the absence of suitable harbours. In the case of the Kerawalapitiya site, shallow water conditions would require a pier distance of 4.6 km to accommodate tankers. Moreover, safety standards require maximum wind velocity of no more than 15 metres/sec, and maximum wave height of 0.5 metres,[123] which in the May-September monsoon period is satisfied only 3 days/month. Thus the report concludes that

> *. . . it is substantially impossible to unload LNG in southwest monsoon season.*[124]

Finally, the report notes that the cost of the LNG terminal would be on the order of $480 million, which would "*effectively double the capital cost of a 750 MW CCCT*."[125]

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[120] 1995 Thermal Options Study, *op.cit*., pg. 4-7

[121] Tokyo Electric Power Services Co. Ltd. *The Feasibility Study on Combined Cycle Power Development Project at Kerawalapitiya*, Final Report, January 1999.

[122] It is worth noting that the author of the report, Tokyo Electric Power Company, is one of the world's largest and most experienced users of LNG.

[123] These are cited as the Japanese Technical Standards for Port and Harbor facilities. Application of lesser standards in Sri Lanka would unlikely be acceptable.

[124] It seems unlikely that the wave and wind conditions at the Puttalam site would be substantially better than at Kerawalapitiya.

[125] If averaged across the potential 750 MW Kerawalapitiya site, this works out at $640/kW.

In 1994 the World Bank undertook a brief evaluation of the 2x150 MW coal-based power plant that had been proposed as an IPP for the Trincomalee site.[126] It reviewed the available technology options, and concluded that only coal, with and without FGD, and gas-fired combined cycle plants, represented baseload thermal options worth a closer economic assessment.[127]

The cost of power from a 300 MW coal plant at 70% PLF was estimated at 4.19 UScents/kWh, increasing to 5.0 cents/kWh if fitted with FGD. For the estimated LNG price of 2.5$/mmBTU (cif), the cost of electricity was calculated at 4.19 c/kWh (see Table A4.1 for assumptions). However, as noted by the report

> *...LNG handling and regasification facilities would have to be set up at Trincomalee port. Diseconomies of scale in LNG preclude a project of this small size. . . . Capital cost estimates for such a facility are not readily available. However, capital costs and operational expenses will likely add $1.5/mmBTU to the cost of gas. This would increase the cost of power generated to 5.5 cents or so.*

Table A4.1: Assumptions[128]

		coal	*coal with FGD*	*CCGT: LNG at 4.$/mmBTU*
capital cost	[$/kW]	956	956	700
pollution control	[$/kW]		165 (FGD)	75 (NOx by SCR)
IDC	[$/kW]	280	328	105
construction time	[years]	6	6	3
capital cost	[$/kW]	1236	1449	883
life	[years]	30	30	20
fixed O&M	[$/kW/month]	0.65	2.7	3.4
variable O&M	[mills/kWh]	3.5	9.5	9.5
heat rate, net	[KCal/kWh]	2187	2187	1854
heat content	[KCal/kg]	6300	6300	10212
annual cap.cost	[$/kW/year]	131.1	153.7	103.7

Source: World Bank, op.cit., Table 6.

We have replicated (to the extent possible) the analysis provided in this report, as

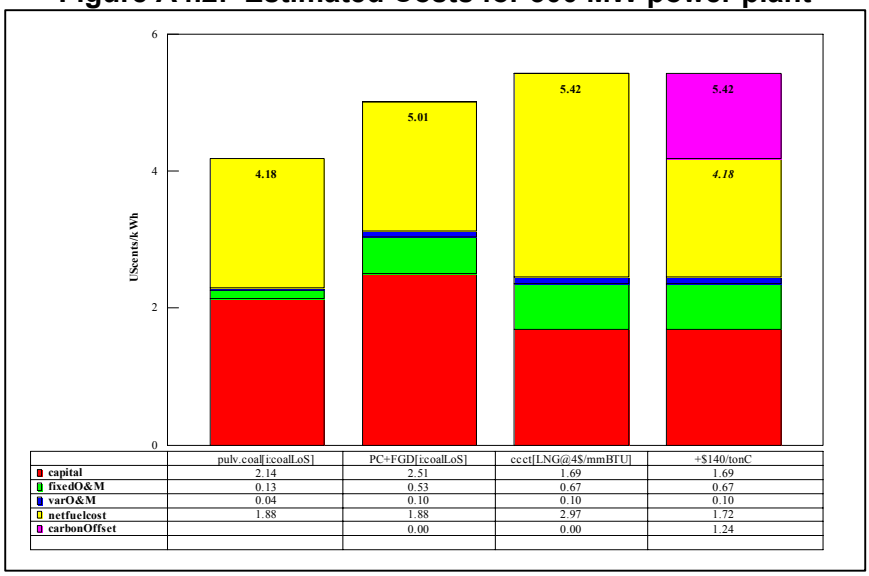
[126] World Bank, Trincomalee Power Plant: Technology Options and Environmental Considerations, 1994.

[127] It also reviewed the status of clean coal technologies -- discussed below in Annex V.

[128] There are a number of potential doubts about some of the assumptions used, but these do not materially affect the results (as shown below in our own analysis that use somewhat different values). For example, capital costs for both coal and CCGTs have decreased over the past few years, and six years for construction of coal plants seems excessively conservative (the detailed feasibility study by Electrowatt of the proposed coal plant at Puttalam suggests a construction period of 3.5 years, which would substantially reduce the IDC burden).

displayed in Figure A4.2.[129] The cost differential between LNG and coal is seen to be about 1.3 cents/kWh (5.42 cents/kWh for gas v. 4.19 cents/kWh for coal).

Figure A4.2: Estimated Costs for 300 MW power plant



	pulv.coal[icoalLoS]	PC+FGD[icoalLoS]	ccct[LNG@4$/mmBTU]	+$140/tonC
capital	2.14	2.51	1.69	1.69
fixedO&M	0.13	0.53	0.67	0.67
varO&M	0.04	0.10	0.10	0.10
netfuelcost	1.88	1.88	2.97	1.72
carbonOffset		0.00	0.00	1.24

Source: World Bank, *op.cit.*

A4.3 Economics of LNG projects in Sri Lanka

It seems clear that the economic and financial feasibility of LNG projects in Sri Lanka requires clarification of several key issues, each of which is discussed below:

- Non-power uses and the problems of scale;
- Project location;
- Gas price;
- Project economics.

Non-power uses

In order to benefit from the economies of scale of LNG, it is clear that a project of economic size in Sri Lanka would require substantial non-power gas use. However, unlike other countries in South Asia which already have a gas pipeline and distribution system, huge investments would be required to establish a new system. Sri Lanka also lacks large energy-intensive industries who could easily switch to from oil to gas were the latter to become available.

To be sure, it may be argued that every country that now has a domestic gas-pipeline system had to begin at some point. However, we know of no example anywhere in the world where such a pipeline system was *started* on the basis of LNG imports. In every example known to us, the impetus for a gas pipeline system was the discovery of

[129] Unfortunately, not all the necessary assumptions are provided in the report (e.g. assumptions for fixed and variable O&M costs, which we have selected in such a way as to best replicate the report's final result in terms of UScents/kWh)

domestic gas reserves (as e.g. in India, Pakistan), or access to gas pipelines fed by gas-rich neighbors (e.g. Switzerland supplied from North Africa via Italy, or Spain from Algeria via Morocco). In all of such cases the delivered gas price was (and generally remains) substantially below $2.50/mmBTU. LNG is readily injected into an existing pipeline system (as e.g. in the US, where east coast LNG projects were seen as a way of meeting high-value winter heating demand peaks, or as in many of the proposed Indian LNG projects),[130] but a gas pipeline system based entirely on imported LNG seems hard to envisage.

A direct pipeline from the Gulf can be ruled out.[131] Even a gas pipeline from a southern Indian LNG terminal implies a distance of some 300-500 miles, which for the small volumes likely to be required in any first stage would be very expensive.[132] Moreover, even if gas were discovered in significant quantities off-shore in South India, there is no reason to believe that the fob gas price to Sri Lanka would be at substantial discount to international price levels.[133] Were gas to be discovered in Sri Lanka waters, the situation is of course arguably different: but there is no evidence of commercially exploitable gas reserves in Sri Lanka.

In countries with acute water supply problems desalinisation represents a potential high-value gas use that could be integrated into a coastal LNG project -- as is being developed by ENRON in Puerto Rico.[134] However, this use is not indicated in Sri Lanka.[135]

It has been suggested that compressed gas might be used in Sri Lanka for transportation use, for indeed this would certainly represent a substantial market.[136]

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[130] Proposed projects in Gujarat contemplate injecting LNG into the existing HBJ pipeline constructed to bring India's domestic off-shore gas reserves to the industrial regions of Gujarat and the Delhi metropolitan area.

[131] Oman to Colombo is roughly 1700 miles.

[132] Assuming a cost of $1 to $1.5 million per mile, and a distance of 350 miles (to the Petronet LNG terminal at Cochin), the investment cost would be $350-500 million, plus terminal and storage facilities at either end. This would add at least $2/mmBTU (to the Cochin regasified LNG price of around $3.75/mmBTU) price at the sort of volume required in Sri Lanka even under any maximum utilisation scenario. In short, if indeed LNG were to be used in Sri Lanka, there is no reason why the LNG terminal would not be in Sri Lanka itself, rather than supplied by pipeline from India. The only reasonable scenario under which piped gas supply from India might ever be possible is if there were some large gas find in (or offshore) southern India itself. But there are no indications that such reserves exist.

[133] According to a 1997 study by the Indian Tata Energy Research Institute (TERI), [*Interfuel Substitution*, Report to the World Bank, July 1997], Singapore pays Malaysia about $2.60/mmBTU for pipeline imports. TERI expects planned exports from Myannmar to Thailand to be priced at $2.50-3.00/mmBTU.

[134] However, ENRON declined to provide CEB with the details of the burner-tip gas price at the Puerto Rico plant (EcoElectrica), or of the busbar electricity cost.

[135] Even in the dry zone, or in Southern coastal locations with drinking water problems (where coastal aquifers suffer from depletion and saltwater intrusion), the cost of desalinisation far exceeds the cost of bringing water by pipeline from the wet zone.

[136] The Daily News article argues the benefits of compressed natural gas as a fuel for transportation.

However, even leaving aside for the moment the economics, it may be noted that the total transportation use of diesel and gasoline in Sri Lanka is about 1.2 mtpy.[137] With a 300 MW power project using about 0.3 mtpy, even a 2 mtpy LNG project would still require a market for 1.7 mtpy, substantially greater than the *total* present transportation demand in the entire country. In any event, again we make the observation that we know of no country anywhere in the world where large scale use of compressed natural gas in transportation (e.g. as in New Zealand) has been undertaken in the absence of large scale domestic gas reserves.

Finally there is the possibility of converting other gas turbine power plants from liquid fuels to gas -- of which some 415 MW of existing and committed capacity would be in place by 2002-2004.[138] But the infrastructure costs of converting these plants would be high, since it would require a pipeline from the import location. Given an economic cost of $3.75/mmBTU for auto-diesel used at these plants (at the comparable 17$/bbl benchmark), the economic justification for conversions seems doubtful.

Given other more pressing priorities for infrastructure investment, it is therefore hard to see an LNG power project serving as a credible catalyst for more widespread use of gas in Sri Lanka.

Project location

The worldwide experience suggests that project economics are strongly influenced by close integration of LNG shipping terminal accommodating large LNG tankers, LNG storage, regasification plant, and immediately adjacent power projects.

Prima facie the optimal location for an LNG terminal in Sri Lanka (as indeed for a coal-based project) is Trincomalee, which benefits from one of the best natural harbors in the region, and that could readily accommodate Capesize vessels. However, given the security situation in the Trincomalee area (and, just as important, the international *perceptions* of the security situation), whatever may be the economics of LNG, such a project location is simply not bankable for the foreseeable future.

Colombo port is already quite congested, and it is hard to see how an integrated LNG project could be accommodated in the Port area. While the worldwide LNG industry has an impeccable safety record, such a location would carry very high insurance costs (if indeed bankable at all) given the history of terrorist attacks in and around Colombo (on oil storage depots and in the nearby downtown area itself).

LNG prices

Japan is the largest LNG importer,[139] and its LNG price is based upon the average

However, we may note that there is no developing country in the world where CNG powered vehicles are based on imported LNG. New Zealand has perhaps the highest proportion of CNG powered vehicles in the world. However New Zealand (as well as Thailand, which also has substantial numbers of CNG vehicles) have substantial indigenous gas reserves, and none import LNG for this purpose.

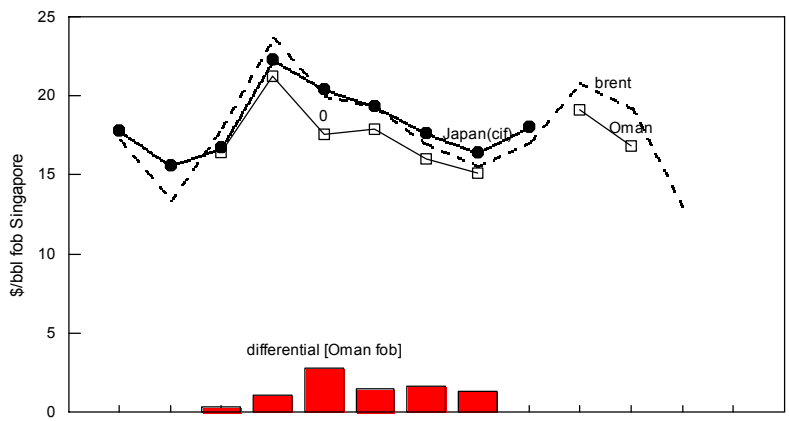
[137] 1998 consumption of diesel was about 1.06 mtpy, and gasoline 0.2 mtpy.

[138] AES and OECF/naphtha CCGTs at Kelanitissa plus 115 MW GT. This would increase by another 150 MW if the Kerawalapitiya CCCT is also implemented.

[139] Japan is the world's largest user's of crude oil for power generation: in 1997 it used 230,000 bbls of

landed (cif) cost of all crude imports (the so-called Japan Crude Cocktail (JCC), published monthly by the Japanese Ministry of Finance). This is shown in Figure A4.3, together with annual averages of Brent and Oman. Since the crude mix in the JCC may vary, there is no one-to-one relationship to any marker; however it may be seen that the JCC roughly tracks Brent (at about $1/bbl above Saudi Light). Average freight Gulf-Japan has been around 90cents/bbl over the past decade, fluctuating between 60 cents and $1.20/bbl.

Figure A4.3: Japanese cif crude oil prices v. marker crude prices fob



	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
differential			0.34	1.06	2.81	1.46	1.62	1.32				
brent	17.20	13.43	17.93	23.65	20.01	19.31	17.02	15.61	17.06	20.84	19.26	12.90
Japan(cif)	17.78	15.60	16.71	22.29	20.37	19.36	17.65	16.45	18.05			
OmanMarker[fob]			16.37	21.23	17.56	17.90	16.03	15.13		19.09	16.84	

Source: Japan Ministry of Finance, "Monthly Trade Statistics".

The LNG pricing formula is designed to even out the volatility of crude prices, so there is a typical 4-6 month lag in LNG prices compared to long-term changes in crude oil price levels. Figure A4.4 shows LNG prices cif Japan,[140] together with Brent and

direct-burn crude (mainly high wax, low sulfur Indonesian crudes). Thus in a declining market, Japanese power company buyers will avoid LNG purchases beyond minimum contractual off-take obligations and simply burn crude: because of the complex pricing mechanism, it takes several months for lower crude prices to work their way into the LNG price.

The Thermal Generation Options Study notes "Crude oil is not considered suitable for direct combustion in diesel engines or gas turbines or boilers in Sri Lanka because of maintenance and operational difficulties and because it is probably more economical to refine it" (pg. 4-7). This is unquestionably so for diesel engines and gas turbines (because of maintenance and operational difficulties), and indeed we know of no such application for utility power generation. However the Japanese experience of burning crude in boilers (where the problems of ash formation are less relevant) suggests that the last reason ("probably more economical to refine") might be worth some reconsideration.

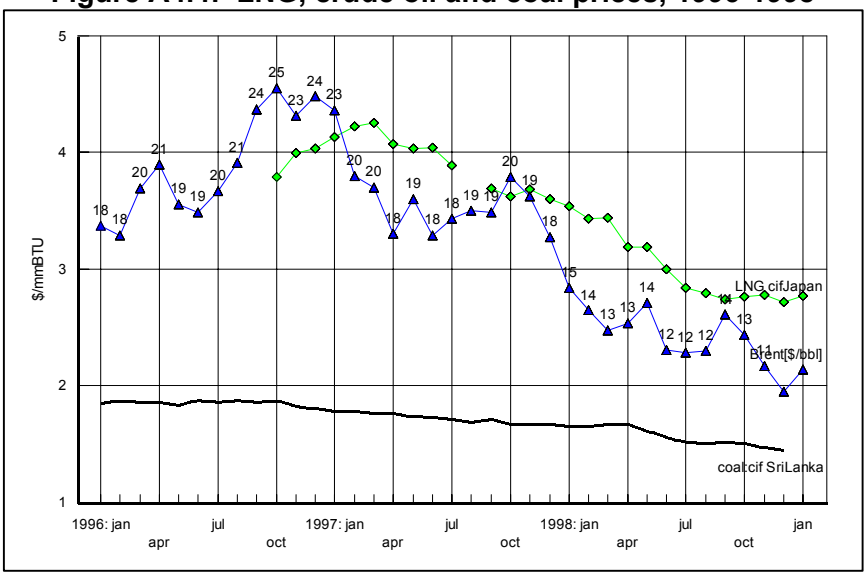
For a discussion of the economics of power generation in Japan, see e.g. T. Toichi, *LNG Development at the Turning Point and Policy Issues for Japan*. Energy Policy, 22 (5) 371-377, 1994.

140 Gas prices in Europe and N. America are of course much lower. In spring, average European border prices were around $2.50-2.60/mmBTU. In August 1998, spot price assessments for UK (Bacton), USA (HenryHub) and Canada (Alberta) were 1.72, 1.84 and 1.36 $/mmBTU, respectively (Petroleum Economist, Sept. 1998).

Australian coal adjusted to cif Sri Lanka.

Some guidance regarding LNG prices in South Asia may be taken from Indian studies.[141] A recent assessment by the Tata Energy Research Institute[142] anticipates burner tip LNG prices in the years 2000-2007 to be around $3.75/mmBTU to $4.50/mmBTU at coastal locations, including the cost of regasification and a project location close to the import terminal.[143]

Figure A4.4: LNG, crude oil and coal prices, 1996-1998



Project economics

The economics of LNG projects thus depend largely upon scale, supply (and transportation) mode, and location. If we exclude pipeline supply from India, the options are as follows:

1. Larger (>100,000 m^3) LNG tankers serving South Indian projects (e.g. Cochin) to make their return journey via Sri Lanka, retaining in their holds such smaller quantities as may be required in Sri Lanka. But whether the LNG vessels used to supply Cochin would be suitable for the relatively shallow waters off Puttalam is unclear.[144] Moreover, the long length of jetty

[141] ENRON, in their presentation to CEB in June 1999, declined to give a specific estimate of the likely cif Sri Lanka price. In a communication in early 1999 to CEB, ENRON would say only that "LNG currently being supplied to Japanese IPPs is approximately $3.20 to $3.60 $/mmBTU."

[142] TERI, *op.cit.*, Section 3.7

[143] Unfortunately, the TERI report is not explicit about the relationship between the Indian cif price and that of specific marker crudes. However it states that Brent prices of between $16 and $18 results in $3.10 to $3.60/mmBTU, "..which works out as a premium of 10-15% on an energy equivalent basis". (TERI, *op.cit.*, pg. 23). Energy equivalence for Brent at $16/bbl is 2.90$/mmBTU.

[144] As in the case of oil tankers, the recent trend has been for larger vessels. In the existing fleet, 28 of 99 tankers are less than 100,000 cu.m in capacity; of those on order, only 3 are smaller than this size. For further details on LNG tankers, their design, and safety record, see e.g. Oil and Gas Journal, June 2, 1997.

required even to reach 15 metre minimum water depth imposes additional costs and handling difficulties: the optimal configuration (as would be possible at Trincomalee, and as is practiced at typical Japanese terminals) calls for compact arrangement of unloading point, storage and regasification.

2. Small LNG carrier (30,000 m^3) under direct charter, directly supplying a 2 x 300 MW scale project.

3. Backhaul supply. ENRON has suggested the following modality of supplying a smaller Sri Lanka project. Large LNG tankers from the Gulf supply Japan. On their return journey, normally empty, they would stop an Indonesian LNG terminal (such as Arun at the tip of Sumatra), take on a partial shipment that is carried to Sri Lanka, unloaded at a southern port (such as Galle), and then return back to the Gulf. Though the incremental travel distance to an Indonesian (or Malaysian) LNG terminal would be relatively small, additional loading and unloading times would also add to costs. Nevertheless, the total shipment cost are almost certainly lower than those of options 2 or 3, above (although how much of this saving would accrue to Sri Lanka rather than to ENRON remains to be discussed).

Table A4.2: LNG freight rates ($/mmBTU)

	India, northwest Gujarat	*India, southeast Tamil Nadu*	*South Korea*	*Japan*
UAE	0.33-0.36	0.53-0.58	1.07-1.12	1.13-1.19
Qatar	0.33-0.36	0.53-0.58	1.07-1.12	1.13-1.19
Oman	0.30-0.33	0.44-0.48	0.99-1.04	1.04-1.09
Yemen	0.30-0.33	0.44-0.48	0.99-1.04	1.04-1.09
Malaysia		0.45-0.49	0.45-0.49	0.51-0.55
Australia		0.58-0.61	0.69-0.74	0.69-0.74

Source: Financial Times Asia Gas Report, February 1999

Even at the more common 2-2.5 mtpy project size, there are few detailed economic and financial analyses in the public domain. Moreover, developers' project proposals to Governments are understandably reluctant to include detailed financial spreadsheets. Nevertheless, we may take one such example as a basis for analysing the economic and financial dimensions of such projects -- namely the proposal of the UK National Power Company (in collaboration with a local company LASMO) for a 2.5 mtpy LNG project at Bundal Island in Pakistan. At this scale -- involving a 700 MW CCCT adjacent to the LNG terminal, with gas sales to other users by pipeline -- the developers proposed a gas price to the power plant (and to the other buyers) of around $4.00/mmBTU for the first ten years, falling to an average of $3.21/mmBTU for years 11-25.[145] The corresponding power price to the purchasing utility (WAPDA) is 5.59 UScents/kWh (levelised over 25 years at 10% discount rate), but substantially front-loaded with a first year power price of 6.73 cents/kWh.

[145] Project Information Memorandum, Figure 4. This LNG project is reviewed in detail in the SLEPTA Background Report, Annex III.

There are other references in the literature for small LNG projects, and Table A4.3 shows an illustrative calculation for the gas price.[146] We have adapted this example to Sri Lanka by adjusting the transportation distance (1,700 rather than 1,000 miles) and the terminal costs. If the fob gulf price is $3.00/mmBTU (equivalent to a crude price of about around 17$/bbl), the burner tip price at Puttalam will be $5.05/mmBTU. Even with stable crude prices of $11/bbl (an unlikely event), the LNG price would still be at around $4.05/mmBTU.[147]

Table A4.3: Price build-up for small LNG project in Sri Lanka (in $/mmBTU)

	Hypothetical LNG-based IPP(1)	*Sri Lanka*	
		Oil Price: 16$/bbl	*Oil Price: 11$/bbl*
LNG price, loaded on ship (fob Gulf for Sri Lanka) 432,000 tons/year	3.00	3.00	2.00
Shipping in small 29,590 m^3 carrier (Century); 186,000 bbls /shipload, 1000 miles distance	0.59		
Shipping to Sri Lanka: 1700 miles: same LNG carrier.		1.00	1.00
LNG terminal (assumed capital cost $80.8 million)	0.85	0.85	0.85
Pipeline to power plant	0.16	0.20	0.20
Delivered to Plant	4.6	5.05	4.05

Source: (1) Based on Mitchell, *op.cit*., pg. 39

A4.4: The ENRON proposal[148]

ENRON's presentation to CEB makes a number of claims that are hard to

[146] As detailed in G. K. Mitchell, *Middle East Fuel Supply and Gas Exports for Independent Power Generation*, Power Economics: Fuel Supply Forum, February 1997, pg. 39. We may note that Mitchell's analysis of such an LNG-based 400 MW IPP results in a price of 5.29 cents/kWh (as compared to the 3.86 cents/kWh estimated by CEB for the Puttalam coal plant.

[147] In the short term, the price outlook for LNG may have improved somewhat as a result of the combined impact of the Asian economic crisis and downward pressure on crude prices. For a review of the current LNG market in Asia, see Petroleum Economist, Sept. 1998, pg. 78-80. Thailand has recently postponed its planned LNG terminal, and Korea Gas Company and other major LNG importers are attempting to renegotiate contract deals. Only baseload contracts are being taken up. This has caused concern for some of the big new LNG export projects in the Gulf; several have already been delayed (and some canceled). Indeed, it is obvious that if the crude price stays at below 15$/bbl for any extended period of time, many new upstream LNG projects are unbankable. The TERI study of India notes that development of new projects in Indonesia (such as Natuna) will require prices of over $4.25/mmBTU. Nevertheless, whatever may be the downward price pressure on LNG, the underlying reason for that pressure is a lower oil price, and hence when LNG prices are low, fueloil prices will be even lower.

[148] Natural gas as a fuel option for power generation in Sri Lanka, Presentation to the Ceylon Electricity Board, June 1999, Enron International.

understand.[149] For example, it claims that an "LNG/Interim Fuel" project requires 2-3 years to start up, while coal requires 4-5 years.[150] Obviously one can build a distillate-fueled CCCT in 2-3 years. But there is nothing in ENRON's experience in India that suggests an *LNG project* can be quickly implemented: even ENRON's Phase I uses naphtha and distillate "interim" fuels, and it required four years from construction begin to commissioning, and seven years from signing of the MoU.[151] If Phase II had been commissioned in 2001 as originally planned, nine years would have elapsed from the date of the MoU.

A4.4 Screening curves

First, suppose that the capital costs of the unloading terminal/ regasification facility are treated as part of the capital cost of the project. This would be the appropriate approach if power were the only off-take at the unloading/regasification terminal. Taking the Tokyo Electric power estimate of the cost of terminal and regasification at $480 million for a 750 MW scale development (640$/kW), and a capital cost of $725/MW for CCCT, then the total capital cost is 1,365$/kW.[152] If the up front infrastructure penalty is the same as for coal, at 7%, then the value to be used in the screening curve analysis is 1.07 x 1365 =$1,460/kW.[153]

Assume further that LNG is priced at 2.81$/mmBTUfob (corresponding to an Arab Light price of $18.5/bbl),[154] and that an efficient backhaul transportation system keeps freight costs to 0.20cents/mmBTU.[155] Thus the cif Sri Lanka price would be $3.00/ mmBTU.

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149 Marketing rhetoric abounds: "LNG strategy should be driven by the electricity and gas market, not by the requirements of an LNG producer . . . being independent from LNG suppliers has allowed ENRON to do what is best for the project and the downstream users."

150 ENRON, June 1999, *op. cit*., "Advantages of LNG for power generation"

151 To be sure, one may always say that the cancellation of the ENRON project by the incoming State Government in 1995, and its subsequent reinstatement after protracted renegotiation (and granting of an equity share to the Maharashtra State Electricity Board), constituted a special circumstance. However it must be understood that the main constraint to a smooth implementation of Dabhol has always been the lack of transparency, and high costs, associated with the MoU arrangement. Such negotiated MoU projects -- especially where the cost of power is substantially above that of its alternatives -- will always be publicly controversial, and involve high risk of delay.

152 In information provided by ENRON to CEB, it was indicated that the total construction cost for the EcoElectrica 505 MW LNG power project in Puerto Rico was $576 million (including contingencies), or 1136$/kW, plus $82 million for soft costs (financing and IDC) for a total completed cost of $658million ($1297/kW). It is unclear whether the 507 MW is net or gross (other ENRON references refer to 522 MW as the size). According to Independent Energy (April 1999), the total cost of the project was $775 million (including the desalinisation facility).

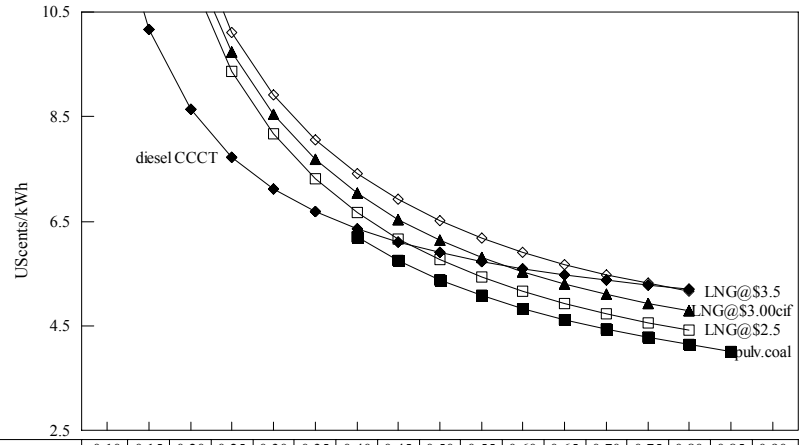
153 Use of the same value as for coal is an assumption that favors LNG, for the relative proportion of infrastructure cost that must be built for the first unit is much larger than for coal.

154 We base this on the $2.58/mmBTU at 17$/bbl used in the proposed Pakistan LNG project.

155 This is substantially less than the expected freight from Gulf to southern India locations (see Table A4.3), and assumes that the savings of the backhaul operation are at least in part passed on to Sri Lanka.

Figure A4.5 shows the resulting screening curves (with additional curves shown for LNG fob Gulf at $2.5/mmBTU and $3.5/mmBTU).

Figure A4.5: Screening curves, LNG



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ diesel CCCT	13.21	10.16	8.64	7.72	7.11	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ LNG@$3.00cif	20.58	14.56	11.55	9.75	8.54	7.68	7.04	6.53	6.13	5.81	5.53	5.30	5.10	4.93	4.78		
⊟ LNG@$2.5	20.21	14.19	11.18	9.37	8.17	7.31	6.66	6.16	5.76	5.43	5.16	4.93	4.73	4.55	4.40		
◇ LNG@$3.5	20.96	14.94	11.93	10.12	8.92	8.06	7.41	6.91	6.51	6.18	5.91	5.68	5.48	5.30	5.15		
△																	

World oil price: Arab Light $18.5/bbl

The corresponding capital cost switching values are shown in Table A4.4. At probable LNG landed costs of $3.0-3.5/mmBTU, the capital costs approach those of diesel-fired CCCTs, and imply unrealistically low LNG terminal/regasification capital costs.

Table A4.4: Capital cost switching values

	LNG plant switching values	
	coal at world oil price of 16$/bbl	*coal at world oil price of 18.5$/bbl*
baseline estimates		
coal	1303	1303
LNG	1461	1461
LNG@2.5$/mmBTU	1285	1226
LNG@2.75	1169	1110
LNG@3	1053	994
LNG@3.5	821	762

75% PLF, 10% discount factor

The corresponding total life-cycle costs are indicated in Table A4.5 The probable minimum price of LNG for 18.5/bbl is 3.0$/mmBTU, falling to 2.75$/mmBTU at $16/bbl (for which the NPVs and penalties are shown in boldface).

Table A4.5: Lifecycle costs ($USmillion,NPV at 10%), 75%PLF

	Arab Light =18.5$/bbl		*Arab light=16$/bbl*	
	NPV	*Δ[coal]*	*NPV*	*Δ[coal]*
coal	794		776	
LNG@ 2.5$/mmBTU	846	52	846	70
2.75	881	87	**881**	**105**
3.0	**916**	**122**	916	140
3.5	986	192	986	210

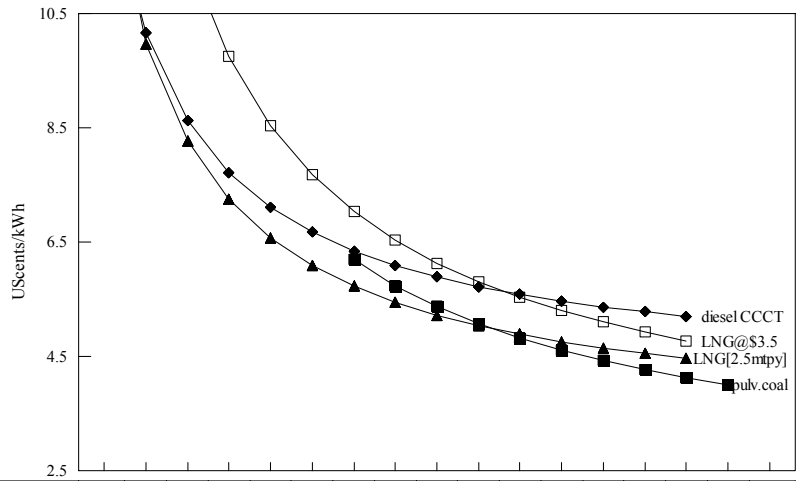
Based upon the results of this screening curve analysis, we note the following:

- Even for intermediate duty (load factors in the 25-50% range), LNG is not competitive with diesel-fired CCCTs. Given the high cost of LNG infrastructure, this is not unexpected.
- It is very unlikely that LNG would be competitive with coal. Even at $2.50/mmBTU, the electricity price at an 80% annual PLF is 4.40cents/kWh (as against 4.04 cents/kWh for coal). The lifecycle penalty for a 300MW plant (at 75% PLF) is likely to be in the range of $US 100-150 million for a world oil price range of 15-20$/bbl.
- The capital cost switching values show that for LNG at $3.00/mmBTU to be competitive with coal, the capital cost would have to fall to $1100/kW. This implies an LNG infrastructure investment of $95 million, rather than the $480 million estimated by Tokyo Electric Power.

Alternatively, one may consider just the power project alone (in which case the capital costs are indistinguishable from diesel fueled CCCTs), and take the gas price at the plant-gate (i.e. including unloading and regasification costs). This would be the appropriate approach if the terminal served other, non-power uses, and the power project accounted for only part of the off-take. Obviously, since the power generation costs themselves are the same as for diesel-CCCTs, and the diesel price is $5.05mm/BTU, then any LNG price less than $5.05 mmBTU would be competitive for intermediate duty. Assuming a 2 mtpy project, the levelised gas price works out at $3.71/mmBTU.[156] The resulting screening curves are shown in Figure A4.7.

[156] As calculated in Annex III of the Background Report for the Pakistan LNG proposal

Figure A4.7: Screening curves for LNG



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ diesel CCCT	13.21	10.16	8.64	7.72	7.11	6.68	6.35	6.10	5.89	5.73	5.59	5.47	5.37	5.28	5.21		
▲ LNG[2.5mtpy]	13.36	9.97	8.28	7.26	6.58	6.10	5.74	5.45	5.23	5.04	4.89	4.76	4.65	4.55	4.47		
⊟ LNG@$3.5	20.58	14.56	11.55	9.75	8.54	7.68	7.04	6.53	6.13	5.81	5.53	5.30	5.10	4.93	4.78		

As expected, under these assumptions, LNG is least cost for intermediate duty. However, we note that above 55% load factor, coal is again least cost. These results are entirely consistent with the Japanese operating practice: in the period 1984-1991 analysed by Toichi,[157] coal plants had an average plant factor of 73.4%; LNG 58.2%, and oil-fired plant 36.8%.

A4.5 Environmental aspects

Advocates of LNG as a fuel for power generation point to the possibility of payments for reduction in emissions of greenhouse gases (GHG) under the implementation of the Kyoto protocol. The avoided cost of carbon works out at 70$/ton (for a cif LNG price of $3.00/mmBTU) or $105/ton at $3.50/ mmBTU). These are far in excess of plausible values of the carbon offset. Moreover, as indicated by the Sri Lanka GHG Overlay Study, there are many more cost-effective ways of reducing carbon (such as dendro-thermal or DSM).[158]

The impact of possible carbon offsets may also be expressed in terms of NPVs over the lifetime of the plant, as shown in Table A4.6. Even at the very optimistic value

[157] Toichi, *op.cit*., Fig 2, pg. 373.

[158] Moreover, as noted in the GHG overlay study, even if it were true that the international market value of the carbon offset were $140/ton, Sri Lanka has gets **no** economic benefit from a carbon payment that exactly equals its additional cost. However, if there is some option with a cost of avoided carbon of, say $20/ton, then at the same value of the carbon offset at $140/tonC there are $120/ton of savings -- of which, if properly negotiated, a substantial portion would accrue to the Government of Sri Lanka. In short, whatever the actual market value of carbon offsets, the options with the lowest cost of avoided carbon can be expected to be implemented first., since the potential benefits to both parties (the developed country providing the payment, as well as Sri Lanka) are thereby maximised.

of $40/ton carbon, the $80million of lifetime revenues does little to offset the high cost penalty.

Table A4.6: Impact of carbon offset revenue (for a 300 MW plant at 75%PLF), as NPVs at 10% discountrate

	carbon offset, $/ton carbon			
	none	*10*	*20*	*40*
lifetime cost of coal plant	776			
lifetime cost of LNG plant	916			
penalty before Carbon offset	139	139	139	139
Lifetime carbon offset revenue	0	20	40	80
adjusted penalty [LNG=$3.00/mmBTU]	139	119	99	59
adjusted penalty [LNG=$3.50/mmBTU]	209	189	169	129

A4.6 Conclusions

We make the following conclusions with regard to LNG:

- Whatever the environmental advantages over coal, LNG would be a high cost option for Sri Lanka, and unlikely to be competitive with coal for baseload duty. Even under the most optimistic assumptions about the scale of any LNG project, LNG is least cost only for intermediate duty (displacing diesel-oil fueled CCCTs).
- It is possible that the cif price of LNG to Sri Lanka may be reduced by a back-haul supply arrangement, as suggested by ENRON. However, at a 2-2.5 mtpy scale, the transportation cost accounts for only a relatively small component, so even if a backhaul operation were feasible, and the savings passed through to Sri Lanka, the cif price reduction would be small. In other words, for a small, power only project, any savings in transportation cost through backhaul is likely to be offset by the diseconomies of scale. If the price at a large project of 2 mtpy is 5.6 UScents/kWh (as in the Pakistan proposal), it is not very likely that the price of a *small* project will be lower.
- Even though LNG prices are less volatile than oil prices, they are still more volatile than coal. Consequently Sri Lanka is exposed to higher price risk if oil prices increase faster than expected.
- The higher costs of LNG may of course be mitigated by carbon offset payments. The actual prospects for such payments are discussed in the GHG study: however, that study concludes that other options would be preferred if carbon offset payments were actually to become available.

Annex V: Other Technologies

A5.1 Renewable Energy

Renewable energy technologies were examined in some detail in the GHG study. In this Section we therefore summarise only the most important points, and show some detailed results for wind energy and dendrothermal.[159]

Wind

Table A5.1 show the assumptions for the screening curve analysis shown in Figure A5.1. We assume that the capital cost of the 3 MW Hambantota demonstration project currently underway, of $1,138/kW, would decrease to $900 for commercial sized plants.[160]

Table A5.1: Assumptions for Wind screening curves

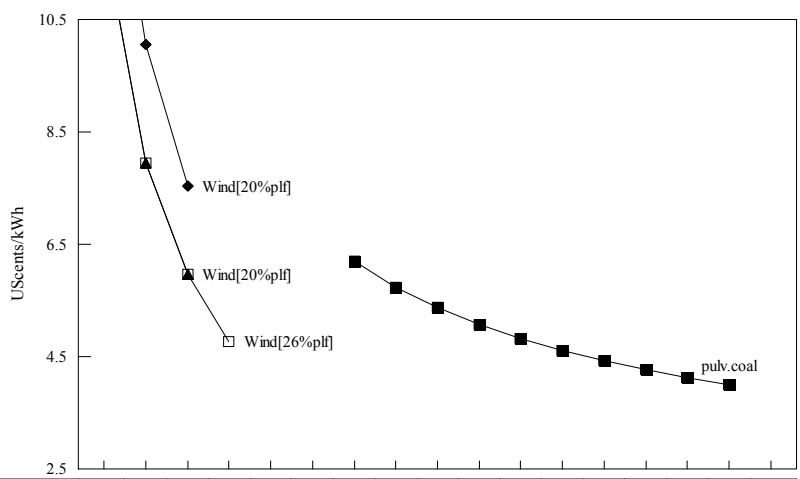
		[1] pulv.coal	*[2] Wind [20%plf] Hambantota*	*[3] Wind [20%plf] $900/kW*	*[4] Wind [26%plf] $900/kW*
total capacity	[MW]	300	3	30	30
overnight cost @ 1998 price level	[$/kW]	1071			
adjustment factor	[ ]	1.14			
nominal economic cost	[$/kW]	1218			
infrastructure adjustm.	[ ]	1.07			
capital cost	[$/kW]	1303	1138	900	900
life	[years]	30	30	30	30
fixed O&M	[$/kW/month]	0.56	0.95	0.75	0.75
variable O&M	[mills/kWh]	2.79			
scheduled maintenance	[days]	40			
forced outage rate	[ ]	0.03			
heat rate, net	[KCal/kWh]	2293			

[159] Among potential renewable GHG mitigation options the GHG Study also examined mini/micro hydro and the photovoltaic solar homes programme.

[160] The estimated financial cost as given by Sunith Fernando and L. Ariyadasa *Wind Energy*, Prespented at the 1999 Annual Meeting, Sri Lanka Energy Managers Association, Colombo, July 1999 is 1,346$/kW. Of the total financial cost, customs duty and GST accounts for 11.38% (which is excluded from the economic cost as a transfer). Further the local costs, amounting to 20%, are adjusted by the SCF. Thus the economic cost=financial cost-taxes&duties- local financial costs*(1-SCF) = 1,138 $/kW.

		[1] pulv.coal	*[2] Wind [20%plf] Hambantota*	*[3] Wind [20%plf] $900/kW*	*[4] Wind [26%plf] $900/kW*
PLF min	[ ]	0.4			
primary fuel		*i:coalLoS*	*wind*	*wind*	*wind*
heat content	[KCal/kg]	6300			
fuel price, cif plantgate	[$/ton]	49			
Representative PLF	[ ]	0.75	0.2	0.2	0.25
PLF max	[ ]	0.87	0.2	0.2	0.25
fixed charge factor	[ ]	0.11	0.11	0.11	0.11
annual capital cost	[$/kW/year]	138.2	120.7	95.5	95.5
fixed O&M/year	[$/kW/year]	6.7	11.4	9	9
total fixed cost	[$/kW/year]	145	132	104.5	104.5
Fuel cost	[UScents/kWh]	1.79			
variable O&M	[UScents/kWh]	0.28	0	0	0

Figure A5.1: Screening curves for wind



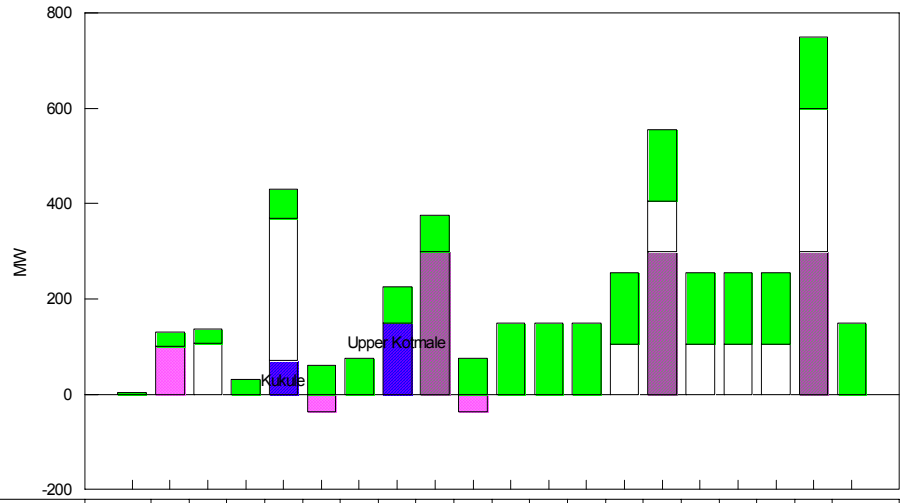
annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ Wind[20%plf]	15.07	10.05	7.54														
▲ Wind[20%plf]	11.93	7.95	5.96														
⊟ Wind[26%plf]	11.93	7.95	5.96	4.77													

The economics of wind power are seen to be strongly influenced by the assumed PLF: an increase from 20 to 26% lowers the energy cost (at commercial scale) from 5.96cents/kWh to 4.77cents/kWh, though still significantly higher than coal at 4.01 cents/kWh. Moreover, since wind power is not dispatchable, the capacity value assumed in these calculations is optimistic.

The GHG Study examines a maximum wind scenario (with some 2013 MW installed over the planning horizon, see Figure A5.2) that eliminates three of the 300 MW coal units of the 1998 CEB base case -- but which still requires the West Coast coal

plant.[161] However, the cost of this scenario is $421 million greater (present value at 10% discount rate) than the 1998 CEB base case, (with a corresponding cost of avoided carbon of $65/ton).[162]

Figure A5.2: Maximum wind scenario



	1999		2001		2003		2005		2007		2009		2011		2013		2015		2017	
hydro					70			150												
coal									300						300				300	
liquid fuels			106		300									105	105	105	105	105	300	
gas																				
diesel		100				-36				-36										
renewables	3	30	30	30	60	60	75	75	75	75	150	150	150	150	150	150	150	150	150	150

Source: GHG Study, Figure 4.2

Dendro-thermal

There are many proposals for dendrothermal power plants for Sri Lanka.[163] The main rationale is their renewable nature, avoiding costly fossil fuel imports. Equally important is employment generation in areas presently characterised by high unemployment. Since dendro-thermal plants would be dispatchable, their capacity value gives them considerable cost advantage over wind or mini-hydro plants.

Table A5.2 shows the technology assumptions for the screening analysis, again using the Puttalam coal project (and LNG) for comparison. The resulting screening curves are shown in Figure A5.3.

Even though the screening curves suggest that dendro-thermal has costs roughly comparable to LNG (at $3.50/mmBTU), the power systems analysis shows that a dendrothermal scenario has lower overall costs than LNG (at this price), largely because dendrothermal can be implemented in small increments that more exactly match the

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161 In the CEB base case, 300 MW coal units are added in 2004, 2008, 2010, 2012, 2014 and 2016. In the maximum wind scenario, 300 MW coal units are built in 2007, 2013 and 2017.

162 GHG Study, *op.cit.*, Table 4.15.

163 See e.g. R. Wijewardene and P. G. Joseph, Growing our own Energy: Complementing Hydro-power for Sustainable Thermal Energy and Rural Unemployment in Sri Lanka, 1999.

demand curve, and avoids the up front infrastructure penalties.[164] Moreover, since dendrothermal is an indigenous fuel, it diversifies the fuel mix, avoids the price uncertainties and balance of payments implications of an imported fuel, and promotes other development objectives (including rural development and reduction of unemployment).

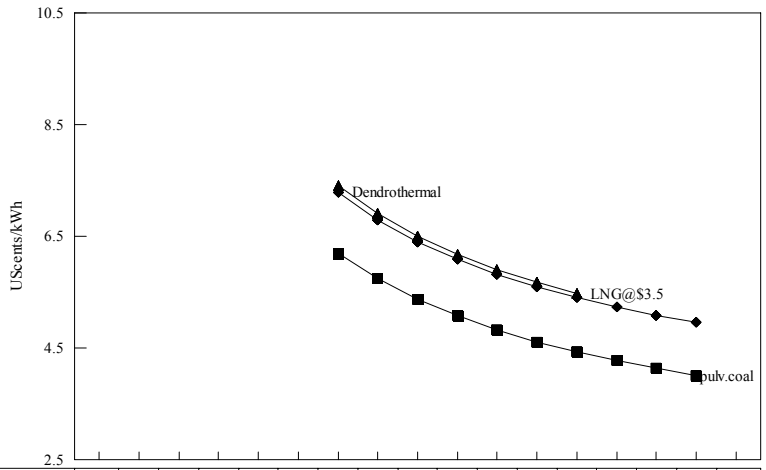
There are several potential issues to be resolved before dendro-thermal becomes a commercial option (as discussed in the GHG study). Nevertheless, the GHG study concludes that a demonstration project to confirm the practicability and economics of a dendro-thermal fuelwood plantation should be undertaken. Such a project has low risk because even if subsequent gasifier or co-firing at the coal plant is not deemed economic (e.g. because the size of carbon offset payments proves to be lower than expected) the fuelwood can always be sold for domestic use.

Table A5.2: Assumptions for dendrothermal screening curves

		[1] pulv.coal	*[2] Dendro-thermal*	*[3] LNG@$3.5*
total capacity	[MW]	300	10	300
overnight cost @ 1998 price level	[$/kW]	1071		
adjustment factor	[ ]	1.14		
nominal economic cost	[$/kW]	1218		1365
infrastructure adjustment	[ ]	1.07		1.07
capital cost	[$/kW]	1303	1200	1461
life	[years]	30	25	30
fixed O&M	[$/kW/month]	0.56	1.8	0.27
variable O&M	[mills/kWh]	2.79	2.5	2.72
scheduled maintenance	[days]	40	40	30
forced outage rate	[ ]	0.03	0.03	0.08
heat rate, net	[KCal/kWh]	2293	4560	1890
PLF min	[ ]	0.4	0.4	0.4
primary fuel		*i:coalLoS*	*fuelwood*	*LNG*
heat content	[KCal/kg]	6300	3800	11250
fuel price, cif plantgate	[$/ton]	49	22	156
	[$/mmBTU]	1.96	1.46	3.5
	[cents/GCal]	779	579	
representativePLF	[ ]	0.75	0.75	0.75
PLFmax	[ ]	0.87	0.86	0.75
fixed charge factor	[ ]	0.11	0.11	0.11
annual capital cost	[$/kW/year]	138.2	132.2	154.9
fixed O&M/year	[$/kW/year]	6.7	21.6	3.3
total fixed cost	[$/kW/year]	145	153.8	158.2
fuelcost	[UScents/kWh]	1.79	2.64	2.62
variable O&M	[UScents/kWh]	0.28	0.25	0.27

[164] GHG Study, op.cit., Mitigation scenario results, Table 5.2.

Figure A5.3: Screening curves for Dendro-thermal



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal							6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ Dendrothermal							7.28	6.79	6.40	6.08	5.82	5.59	5.40	5.23	5.08	4.96	
▲ LNG@$3.5							7.41	6.91	6.51	6.18	5.91	5.68	5.48				

Mini hydro

Mini-hydro is identified in the GHG study as one of the "win-win" options, and examines a scenario with an additional 45 MW of mini-hydro implemented as IPPs over the years 2001-2007. However, the report identifies a number of issues related to IPP financing, and to the calculation of avoided costs in the CEB system which are the basis for the tariff.

Other renewable technologies

Many of the other renewable energy technologies -- such as wave and tidal energy, OTEC, solar chimneys etc. -- that have been advocated for application in Sri Lanka are so far from the stage of being commercially proven and/or economically viable that they may safely be dismissed as serious alternatives for at least the next twenty years. Opportunities for small scale demonstration projects may of course be undertaken, but even if successful, commercial demonstration will require at least another decade before they could be considered for full scale implementation.

A5.2 Nuclear

Nuclear power is not a realistic option for Sri Lanka. Though its advocates argue that it may reduce GHG emissions,[165] that would come at a very high cost. A recent study for the Indian state of Haryana[166] -- which like Sri Lanka has no indigenous coal[167]

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165 See e.g. K. Matsui, Global Demand Growth of Power Generation, Input Choices and Supply Security, Energy Journal, 19(2), 1998, pg. 93.

166 India: Environmental Issues in the Power Sector: Haryana Case Study. Report by International Development and Energy Associates to the World Bank, 1999.

167 Haryana imports coal from Bihar over a distance of some 1,200 km.

-- concludes that other GHG emission reduction options have much lower costs of avoided carbon.[168]

There are other problems, most notably that of financing. We know of no nuclear plant anywhere in the world implemented as an IPP. Neither the World Bank nor Sri Lanka's traditional sources of concessionary finance for power projects, notably Japan's OECF, provide finance for nuclear projects. In short, nuclear power does not represent a practical option for Sri Lanka in the near term.

A5.3 Clean Coal

CEB's assumption is that the coal project would use conventional pulverised coal technology, using imported low-sulfur coal that could meet ambient air quality and SOx emission standards without FGD. As discussed in the Background Report,[169] there is little evidence of a significant sulfur premium for coal in Asia-Pacific markets (unlike for heavy fueloil, and for coal in Europe and North America), so purchase of the lowest possible sulfur content coal carries negligible economic penalty.

The question of whether a Sri Lanka coal project should be fitted with FGD has been examined on previous occasions. A 1994 World Bank study concluded that FGD would not be cost-effective when compared with other options for reducing ambient sulfur oxide levels (use of lower sulfur diesel fuels in transportation), or when compared to the benefits achievable for the same cost in other sectors (public health, hospital diagnostic equipment etc.).[170] A second World Bank study of a proposed IPP Trincomalee coal project also showed that FGD was not required to meet ambient air quality standards.[171]

The use of the more advanced clean coal technologies such as pressurised fluidised bed combustion (PFBC) and integrated coal gasification combined cycle (IGCC) is also unwarranted for Sri Lanka. These technologies have higher costs than conventional pulverised coal, and can compete only in situations where coal plants would require FGD; where cheap but low quality fuels are available (as e.g. in India and China); or where the environmental requirements are so stringent that conventional plants would not be tolerated.[172] In any event, other than atmospheric fluidised bed combustion, most of the other technologies (IGCC, PFBC, coal-water fuels burnt in diesels, etc.) cannot yet be regarded as commercially available; and some, such as PFBC, are presently offered only by a single vendor, ABB.

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[168] The cost of avoided carbon for nuclear is estimated at $27/ton, as opposed to natural gas (at economic prices based on imported LNG) of $20/ton, and DSM, combustion of agricultural residues and Nepalese hydro which are all win-win. See Haryana Case Study, op.cit., Table 6.2

[169] SLEPTA Background Report, Box 10.

[170] P. Meier and M. Munasinghe, *op.cit.*, 1994.

[171] World Bank, *Trincomalee Power Plant: Technology Options and Environmental Considerations*, 1994. The conclusions of this study were reviewed above in Section 5.

[172] K. Oskarsson *et al., A Planner's Guide for Selecting Clean-coal Technologies for Power Plants*, World Bank Technical Paper 387, Washington DC, 1998.

To examine the order of magnitude of the trade-offs, we take AFBC as the representative clean coal technology, and compare it to coal (as proposed), and coal with FGD. The assumptions are shown in Table A5.3, and are based on a recent World Bank study of clean coal technologies.[173] Based on this generic information, we have added the *incremental* capital and operating costs to the baseline coal plant costs used earlier in Annex I.

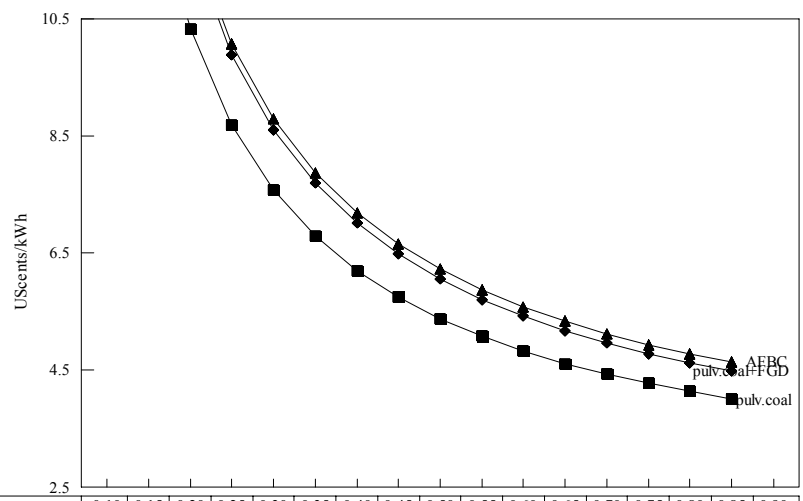
Table A5.3: Assumptions for screening analysis of AFBC

	MW	*fixed O&M* *$/kW/year*	*var O&M* *mills/kWh*	*capital costs* *$/kW*
pulverised coal (PC)	150	36	2.0	1350
	500	27	5.0	1050
incremental costs for wet FGD (1)	300	+12-13	1.5-2	160-240
as taken in this report	300	+6	+1	+160
AFBC	150	44	8.5	1400
	200			1300
incremental costs for AFBC as taken in this report		+8	+3	+150

Source: Oskarsson et al., op.cit.

(1) strongly dependent upon type of process. For seawater process we may take the low figure for capital costs, and 50% of O&M costs (since the seawater process avoids the significant costs of wet-limestone systems for both limestone acquisition and sludge disposal).

Figure A5.4: Screening curve for AFBC



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal	18.61	13.10	10.34	8.68	7.58	6.79	6.20	5.74	5.37	5.07	4.82	4.61	4.43	4.27	4.13	4.01	
◆ pulv.coal+FGD	21.39	15.00	11.81	9.89	8.61	7.70	7.01	6.48	6.05	5.71	5.42	5.17	4.96	4.78	4.62	4.48	
▲ AFBC	21.64	15.22	12.00	10.08	8.79	7.87	7.18	6.65	6.22	5.87	5.58	5.33	5.12	4.94	4.77	4.63	

The resulting screening curves for the cost of electricity as a function of PLF are shown in Figure A5.4. As expected, AFBC has significantly higher costs than PC+FGD, from which it is reasonable to conclude that if indeed one wished to reduce sulfur

[173] K. Oskarsson *et al., op.cit.*

emissions to below those presently proposed for the Puttalam project, FGD rather than AFBC would be more cost-effective.

The corresponding life-cycle costs are shown in Table A5.4. The magnitude of the incremental costs, compared to the baseline, are significant.

Table A5.4: Life-cycle costs (NPV, $US million)

	NPV	*Δ(coal)*
Coal	794	
coal+FGD	887	94
AFBC	917	123

Arab light 18.5$/bbl; 75% PLF, 10% discount rate

Table A5.5 shows the corresponding sulfur emission levels, together with those of some of the other options examined in previous sections of this report. The trade-off between sulfur emissions and cost is shown in Figure A5.5.

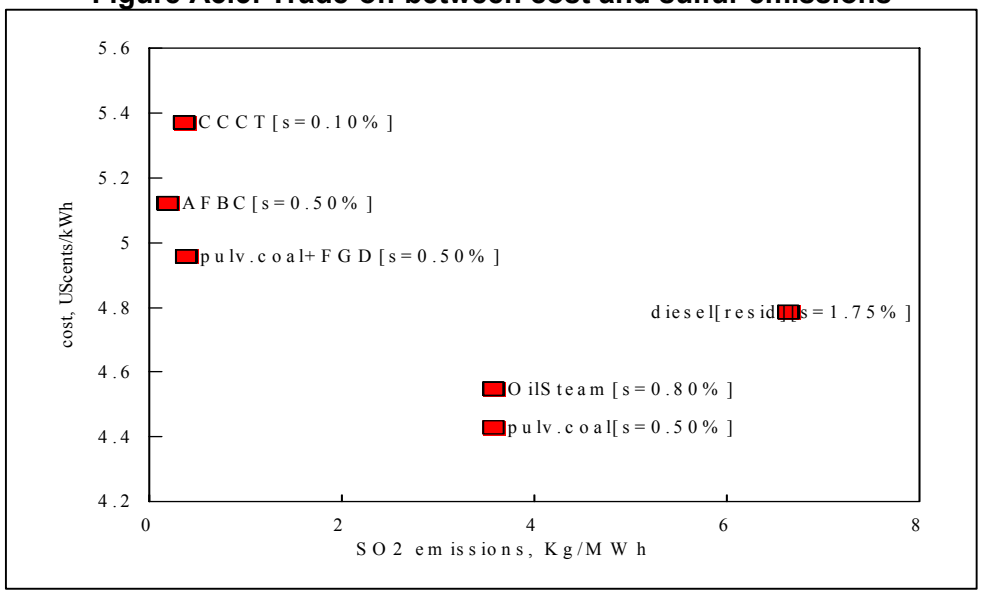
Table A5.5: Summary of sulfur emission levels

	mg/MJ	*$KgSO_2$ /MWh*	*tons/year for 300MW plant at 75%PLF*
Proposed emission standard	520		
coal, 0.5%S ("average" coal at Putalam)	372	3.57	7030
oil-steam, 0.8% sulfur	372	3.57	7030
oil-steam, 1.1% sulfur(1)	520	5.28	10409
oil-steam, 1.6% sulfur (ECNZ proposal)			
CCCT, autodiesel 0.1%S	45	0.36	706
diesel using Residual (e.g. Sapugaskanda)	813	6.64	13087
: at 1.75% sulfur(2)			
at 3.5% sulfur	1626	13.28	26174
coal + FGD	38	0.38	740
AFBC	19	0.18	359

(1) this is equivalent to use of 3.5% sulfur oil, treating 75% of the stack gas by FGD @ 90% removal.

(2) Though 3.5% S is the specification, actual sulfur content of fueloil used at Sapugaskanda is in the range of 1.75 to 2.25%S. Particularly in recent years this sulfur content has been lower than spec. as a higher fraction of low-sulfur crudes has been refined.

Figure A5.5: Trade-off between cost and sulfur emissions



A5.4 Demand side management

The role of DSM has also been examined in the GHG study.[174] It concludes that even if all the potentially economic DSM were implemented, the need for baseload additions remains. In some of the scenarios, DSM may permit some of the later coal units to be deferred by one or two years; however, in none does DSM *replace* coal. In short, DSM has a role to play in Sri Lanka, but, unlike India, its role is limited.[175]

A5.5 Conclusions

Renewable energy and demand side management do have a role in Sri Lanka. If carbon offsets become available, the GHG study concludes that dendro-thermal projects may be attractive, initially by co-firing at coal projects. The study concludes further that mini/micro hydro, DSM and dendrothermal all represent much better hedges against uncertainty in the value of the carbon offset than LNG, which, while it also reduces carbon emissions (relative to coal), exposes Sri Lanka to undesirable lock-in effects.

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174 GHG study, *op.cit*., Section 4.

175 The vast potential for DSM in India is a consequence of large-scale use of electricity for tubewell irrigation, often provided at negligible or no cost, resulting in massive inefficiency, overloaded rural feeders, and high T&D loss rates. Rehabilitating 11kV feeders coupled with installation of high-efficiency pumpsets therefore brings high economic benefits to most Indian systems.

Application of clean coal technology does not appear to be warranted for Sri Lanka. The technologies that are at or close to commercial availability -- such as atmospheric fluidised bed combustion (AFBC) -- are most appropriate at mine-mouth plants using low quality coals (and hence their potential application in India and China). But because Sri Lanka has no indigenous fossil resources, and must import high-quality coal over relatively long distances, the economic rationale for AFBC is absent.

Annex VI: Impact of Financing

In this Annex we turn to financial analysis. The objective is to determine whether the comparative rankings of technologies, identified in the previous sections on the basis of economic costs, change when *financial* rather than economic costs are used.

A6.1 Taxes and duties

The first difference between economic and financial costs concerns transfer costs -- customs duty on equipment, excise taxes, defence levies, taxes (and subsidies) and duties on fuels. Even if investment decisions are made on the basis of economic costs, whether these transfer payments have a seriously distorting *economic* impact depends, in turn, on

1. The criteria for dispatch -- i.e. whether dispatching is based on economic or financial marginal cost. If dispatch is on the basis of financial cost (to CEB), then, obviously, the consistency of energy taxes becomes an issue. Also, if investment decisions are made on the basis of economic dispatch in a system planning model, but actual dispatch is on a financial basis, then resources may be misallocated.
2. The extent of discrimination against IPPs. If, for example, CEB is exempted from duty on liquid fuels, but an IPP is not, then if dispatch is based upon financial marginal costs, the effect may be to discriminate against dispatching an IPP.
3. Even if the equity returns were guaranteed to the IPP through a fixed charge (with additional incentives tied not to generation but to availability) -- so that there is no financial discrimination to the IPP from non-optimal dispatch -- a more efficient IPP may be dispatched less (if it is burdened with a higher tax rate on fuel) than a less efficient CEB-owned plant. This may lead to higher than necessary fuel imports.

The total burden of fuel taxes is material, as summarised below in Table A6.1

Table A6.1: Impact of taxes on liquid fuels

	cif colombo, 11/8/99,Rs/ton [1]	*price charged by CPC,Rs/ton [2]*	*Bank charges, port dues,etc. [3]*	*total tax Rs/ton: [4]= [2]-[1]-[3]*	*%tax =[4]/[1]*
Barge Project (IPP), 180cst fuel oil	9067	12371	742	2562	28.2%
AES project (IPP)	12000	18597	804	5993	49.9%
Sapugaskanda diesels (residual oil)	8807	12033	736	2490	28.2%
Kelanitissa gas turbines (CEB)	12000	18597	804	5793	48.2%
AsiaPower	8807	12033	736	2490	28.2%
Lakdanavi, 180cst fueloil by bowser	9067	12371	742	2562	28.2%

Source: CPC

It is evident from the above that the rate of customs duty on imported diesel (30% of cif) is significantly higher than the customs duty on fueloil (10%). *Prima facie*, at least according to this nominal pricing structure, IPPs and CEB are subject to the same taxes. However, we understand that CEB has been (or will be) exempted from some or all fuel taxes except the defence Levy. If these same concessions are not also given to IPPs, then the previously noted distortions may well arise. Similarly, given the above structure of levying taxes and duties on oil, then distortions would occur if similar taxes are not also levied on coal. The World Bank has previously recommended a simplification of the petroleum tax system:

> *The present structure of duties, taxes and levies on petroleum and petroleum products is very complex . . . There is a strong case for simplifying the present system of taxation to have a single point application and collection at the retail level and to save high administrative costs. It is therefore recommended that the Government introduce a simplified taxation system by, for example, combining all taxes and levies into a sales tax on the final retail price.*[176]

Such a simplified system would be desirable also from the power sector point of view. A full analysis of the impact of differential rates of taxes and duties on economic dispatch is beyond the scope of this present study, but should be undertaken. Such a study ought also to examine the impact on dispatch of PPAs signed to date with IPPs. Whatever may be the distortions introduced by these issues under current arrangements, the small size of such plants (48 MW in the case of AsiaPower, 20 MW in the case of Lakhdanavi) ensures that their impact is relatively minor. However, once the 150 MW AES and 60 MW Barge projects come on stream, particularly once they get displaced by

[176] World Bank, Energy and Project Finance Division, Country Department I, South Asia Region, Sri Lanka, *Petroleum Sector Study*, September 1996.

any baseload project in the merit order, the impact of such distortions may become more serious.

A6.2 Private vs concessionary financing

The second major difference between economic and financial costs is due to the difference between private, public and concessionary financing. To illustrate the impact of financing modality, we make the following assumptions

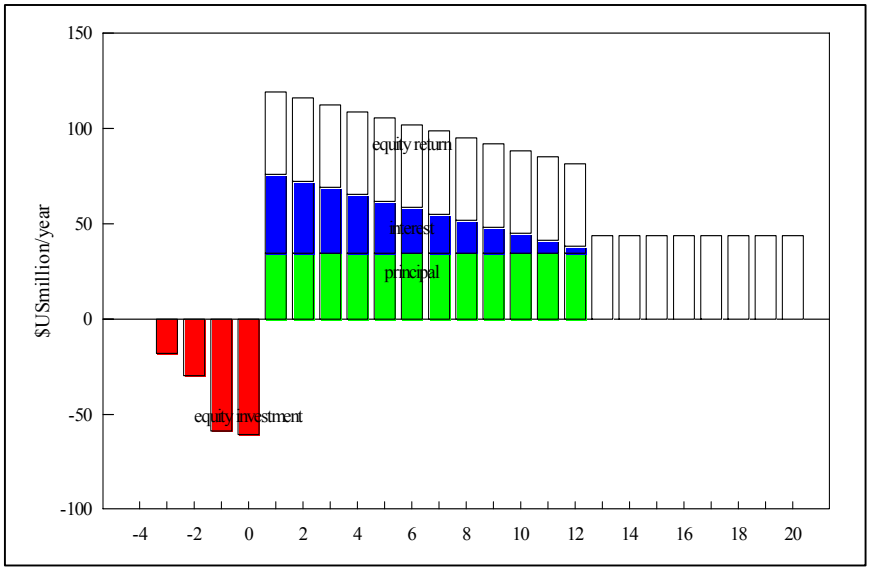
- 30:70 debt equity ratio, with equity disbursements during the construction period *pari passu* with debt.
- For privately financed IPPs, offshore dollar financing at 10% with a 12 year tenor. IDC is assumed rolled into the debt (and with construction financing also at 10% interest).[177] Figure A6.1 shows the major elements of cashflows under these assumptions.
- For concessionary OECF financing we assume 30 year tenor with 10 year grace and interest at 1.8%[178].
- For concessionary finance, the equity contribution (of CEB or of its unbundled successor) is costed at 16%.
- The financial capital cost is defined as the present value (at the opportunity cost of capital, 10%) of the stream of equity returns and debt service payments.
- Total soft costs (incl. IDC) are taken as 21%.[179]

[177] On Dec 2, 1999, 1-month $LIBOR was 6.478%; 12-month $LIBOR 6.29% (or sterling 12-month LIBOR 6.56%). A major international IPP would do well to get LIBOR+3 (e.g. as in ENRON's Dabhol II financing), and more likely LIBOR+3.5; so 10% would be fairly representative of current borrowing costs. We examine below the sensitivity of results to variations in debt terms.

[178] Assumptions as per the detailed financial analysis in Tokyo Electric Power's feasibility study of proposed Kerawalapitiya project. Given extremely low interest rates in Japan (discount rate in early December 1999 was 0.5%), the present interest rate on OECF financings may be somewhat lower. However, even lower interest rates than that assumed here would not change our conclusions.

[179] This is lower than the soft cost portion in ECNZ's proposal for Marsden B, which is 30% of the total.

Figure A6.1: Equity returns for IPP financing, Unit 1, IRR=20.6%



The results are summarised in Table A6.2 in terms of $/kW and in Table A6.3 as total capital costs. For the first unit, the present value of the difference between typical IPP and OECF financing is $588 million. These differences in *financing packages* are very much greater than the differences between *technologies* evidenced in our earlier comparisons of lifetime NPVs. The inference is clear: for the baseload unit, the choice of financing mode has a much greater impact than whether the technology used is coal or heavy fueloil.

Table A6.2: Effective capital cost, $/kW

	Unit 1	*Units 2&3*	*Average*
Overnight (Table A1.5)	*1450*	*787*	*1077*
OECF funding			
completed cost (incl. IDC and soft costs)	1450	787	1077
effective financial capital cost	784	425	582
as typical Indian MoU IPP			
completed cost (incl. IDC and soft costs)	1935	1050	1437
effective financial capital cost	2742	1488	2037

Source: Background Report, Annex V

Table A6.3: Lifetime cost of capital (equity returns & debt service)

	Unit 1	*Units 2&3*	*Average*
concessionary financing			
completed cost	435	236	323
NPV	235	128	175
completed cost	650	315	431
NPV	823	446	611
difference in NPV	**588**	**318**	**436**

$US million; NPVs at plant commissioning.

Similar conclusions apply to other technologies as well. For example, the cost of hydro plants under OECF financing is shown in Table A6.4. Again we see effective financial costs that are around 50% of the assumed nominal capital costs.

Table A6.4: Effective cost of hydro plants

	MW	*overnight cost*		*penalty for uncertainty (as per CEB 1998 study)*	*economic capital cost, CEB definition*	*financial cost, OECF financing*
		$USmill	*$/kW*	*[%]*	*$/kW*	*$/kW*
Kukule	70	186				1436
Upper Kotmale	150	372				1341
Broadlands	40		2675	2	3152	1377
Ging Ganga	49		2405	10	2851	1150
Moragolla	17		3390	10	4010	1300
Uma Oya	150		2324	5	2876	1163

A6.3 Impact of debt denomination

The magnitude of the difference between OECF concessionary funding, and privately financed projects will however be dependent upon some additional important assumptions. OECF financing is necessarily denominated in Yen, whereas IPP debt (particularly for large projects) is most likely to involve several participating banks and several currencies,[180] and most probably include a significant portion of debt denominated in US dollars. If the dollar continues to depreciate against the Yen, then OECF Yen financing --even at concessionary rates -- may be more expensive than the above comparisons suggest. This is especially true where long grace periods are involved, and where what effectively matters is the Yen: dollar exchange rate 10-20 years hence.

Figure A6.2 illustrates the historical Yen to dollar exchange rate: since 1970 the average rate of depreciation of the $ against the Yen has been 4.1%.[181]

[180] Recall the example given of the ENRON Dabhol Phase II financing (Box 3).

[181] As always it depends upon the time period selected: the average rate from 1973 to 1999 is 4.1%; from 1980 to 1999 is 6.3%, from 1990 to 1999 is 3.4%

Figure A6.2: YEN: $ exchange rate

Source: IMF, International Financial Statistics (Market rates, period average)

The impact of this long-term depreciation rate on the financial comparisons is illustrated in Table A6.5. Even under the worst case (no Yen, but 100% $ financing in the IPP case, and an assumed 7% year depreciation of the dollar against the Yen -- which exceeds the depreciation rate of any long-term historical period), the difference in NPVs for the first coal unit is still $339 million.[182]

Table A6.5: Impact of dollar depreciation: Financing of first coal unit

	yen:$ in year 10	*NPV $US m*	*equiv. $/kW*	*Δ(IPP) $US m*
IPP, 100% dollar financing		823	2742	
Concessionary fin. 100% Yen				
$:Yen depreciation rate				
Zero	100	235	784	588
1%	90	255	849	568
2%	80	278	926	545
3%	72	306	1019	517
4%	65	339	1130	484
5%	58	379	1262	444
6%	53	427	1422	396
7%	48	484	1614	339

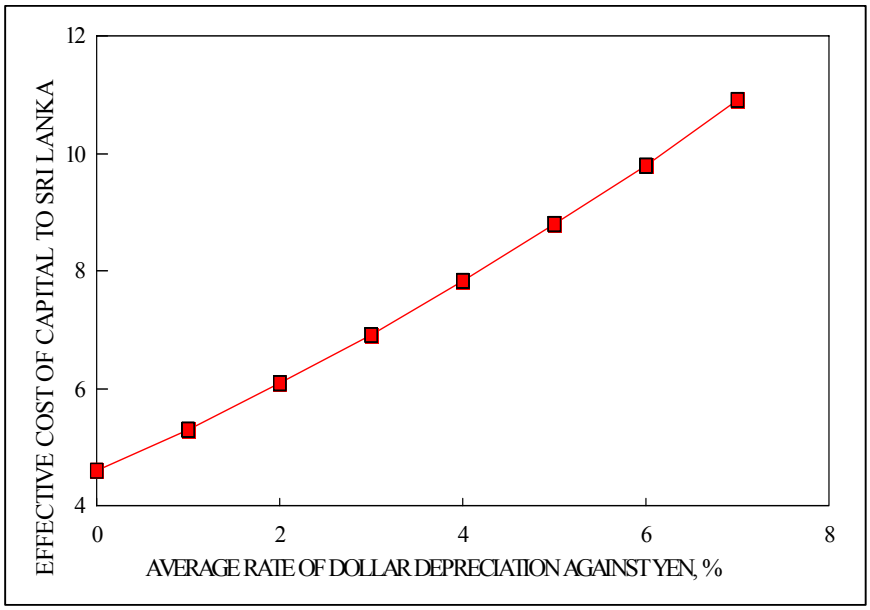
[182] However, there are other factors as well that affect these comparisons that we have ignored here, notably the extent of any Yen component in the comparable IPP financing. However, ignoring this ensures a conservative result (and tends to overstate the effect of changes in the nominal dollar:Yen exchange rate).

A6.4 The cost of capital

We noted in the economic analysis that while the cost of capital in public sector projects should be taken at the SDR, the cost of capital in private sector projects may be significantly higher. Indeed, in the case of foreign financed IPPs (in which both debt and equity is foreign), the economic costs are *equal* to the financial costs. The effective cost of capital may be defined as that discount rate which makes the stream of equity returns and debt service payments (interest and principal) equal to the completed cost. As we shall see in the next section, variations in the cost of private debt (or of the tenor of private loans) have a relatively small impact. However, the equity return achieved by the developer proves to have a significant impact, and is comparable to the differences between private and concessionary financing -- which points to the importance of competitive bidding for IPP projects.[183]

The effective cost of capital cost of capital associated with concessionary OECF financing in Yen is dependent upon the assumed depreciation rate of the dollar against the Yen -- a relationship shown in Figure A6.4. Given historical depreciation rates, and the probability that the corresponding privately financed IPP would also have some Yen debt, it would seem reasonable to assume an effective cost of capital of around 7% (rather than the nominal interest rates of less than 2%).

Figure A6.4: Cost of capital for OECF financing



One of the arguments against concessionary financing is that this creates an additional actual or contingent liability upon the Government for which there may be limited headroom. Obviously, if sovereign guarantees are offered to IPPs, the

[183] This is illustrated in the Background Report, Annex V for the case of the ECNZ proposal for the Marsden B project, where we observe very large variations in effective capital cost, ranging from $400 million (and an IRR of 33%) in the case of ECNZ's Oct 1998 offer, to $255 million at a more reasonable 16.5% IRR, a difference of $145 million.

Government incurs an even larger contingent liability (since the amounts to be guaranteed are very much larger than in the concessionary financing case).

However, this is a transition issue. Sovereign guarantees may need to be offered to the first few IPPs, but subsequent projects may be able to proceed without them (provided power sector reform as a whole proceeds satisfactorily, that the regulatory commission establishes a track record of adequate tariff-setting). Indeed, this is the experience in India, where the first few IPPs (the "seven so-called "fast track" projects, including ENRON's Dabhol project) received federal guarantees, but none are to be given in the future.

A6.5 Impact of debt terms

Table A6.7 shows the impact of debt terms (interest rates and tenors) upon the effective cost of capital to Sri Lanka and on the effective capital cost. With rates spanning from 8 to 12% and tenors from 10 to 15 years the variation in effective cost of capital is relatively small -- ranging from 14.9% to 17.6%. This should be compared to the corresponding figures for variations in equity returns (14.2 to 23.6%). Similarly the effective capital cost ranges from $261million to $294 million, a range of $30million -- to be contrasted with the range of $145 million that is a consequence of negotiation of equity returns.[184]

Table A6.7: Impact of debt terms

Cost of capital, Λ	*10 years*	*12 years*	*15 years*
8% interest	15.6	15.3	14.9
10% interest	16.6	16.3	16.0
12% interest	17.6	17.4	17.1
Effective capital costs, $US million			
8% interest	261	260	258
10% interest	276	276	276
12% interest	291	292	294

Calculations of □ assume an investor IRR of 19%

A6.6 Screening curve analysis

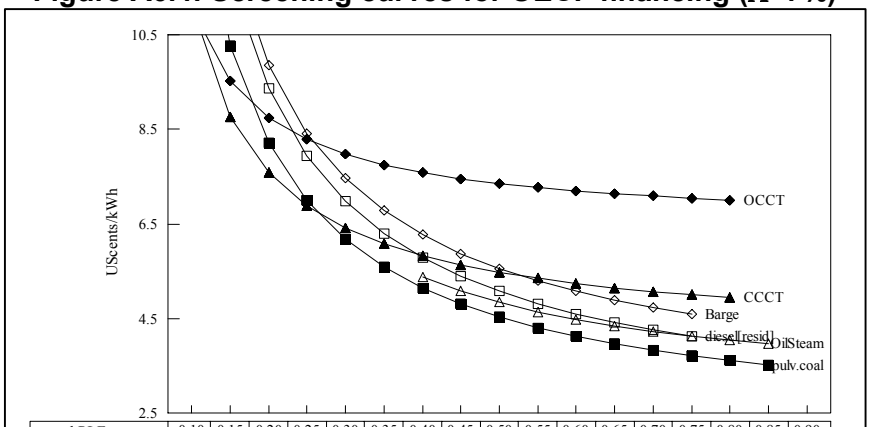
We can now revisit the screening curve analysis using financial capital costs. The question of interest is whether the technology rankings change at the sorts of costs of capital that actually reflect concessionary or private financing. Figure A6.4 shows the results for concessionary financing taking the cost of capital at 7% that corresponds to OECF financing. It is evident that the advantage of coal over oil-steam (other things like oil price equal) is more pronounced at this lower cost of capital, as indicated in Table A6.8. Indeed, these lifetime costs shows that even at $13/bbl, coal still has an advantage over oil-steam.

[184] Thus the most imnportant issue in negotiating an MoU project is not how savings in financing can be passed through to the buyer, but what equity return is both reasonable and commensurate with risk.

Table A6.8: Lifetime costs at 7% cost of capital (OECF financing)

	$13/bbl		*18.5$/bbl*	
	NPV	*Δ(coal)*	*NPV*	*Δ(coal)*
coal	855		906	
CCCT	947	92	1224	317
diesel (residual)	902	40	1008	102
diesel (furnace oil)	1018	162	1124	217
oil-steam	866	10	1008	102

Figure A6.4: Screening curves for OECF financing (Λ=7%)



annual PLF	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90
■ pulv.coal	14.37	10.27	8.22	6.99	6.17	5.58	5.14	4.80	4.53	4.30	4.12	3.96	3.82	3.71	3.60	3.51	
◆ OCCT	11.07	9.52	8.75	8.28	7.97	7.75	7.58	7.46	7.35	7.27	7.20	7.14	7.09	7.04	7.00		
▲ CCCT	11.11	8.76	7.59	6.88	6.41	6.08	5.83	5.63	5.47	5.34	5.24	5.15	5.07	5.00	4.94		
⊟ diesel[resid]	16.52	11.75	9.37	7.94	6.98	6.30	5.79	5.39	5.07	4.81	4.60	4.41	4.26	4.12			
◇ Barge	17.01	12.24	9.85	8.42	7.46	6.78	6.27	5.87	5.55	5.29	5.07	4.89	4.73	4.59			
△ OilSteam							5.37	5.07	4.83	4.64	4.48	4.34	4.22	4.12	4.03	3.95	

A6.7 Conclusions

We draw the following conclusions from this discussion:

1. While OECF financing at interest rates of 2% and less appears very attractive, the effective cost of capital is likely to be higher as a consequence of the probable continued depreciation of the US$ against the YEN. Depending upon assumptions, the actual effective cost of capital may be several percentage points higher.

2. Nevertheless, the effective capital cost (defined as the present value of the stream of equity returns and debt service payments) of OECF financing is still substantially lower than an IPP financing. Even if the dollar:Yen depreciation rate is taken as an average of 4%, and the IPP financing contains no Yen debt component, the difference is in excess of $300 million. Differences of this order of magnitude are significantly greater than differences between technologies.

3. At the lower costs of capital implied by concessionary financing, the more capital intensive technologies will have an advantage. As we shall see in the

next section, this applies especially to the most capital intensive of all, namely hydro. In the case of coal v. oil-steam for baseload, under OECF financing coal has an advantage even at oil prices of $13/bbl (under baseline assumptions for capital cost). It seems reasonable to conclude that *if* OECF financing is accepted, coal is a robust technology/fuel choice.

4. However, at the higher costs of capital implied by IPPs, the advantage of coal is less clear, particularly at low oil prices.
5. Recitations of capital cost by IPPs give a misleading picture of the true cost of capital, for the actual cost of capital investment will be given by the PV of the stream of fixed plant charges (equity returns and debt service). We note that such differences are again not only greater than the differences between technologies (for equivalent duty), but comparable to the differences between private and concessionary financing.
6. The differences in cost attributable to differences in debt financing terms are also far smaller than the range of costs implied by the variations in equity returns encountered in MoU negotiations.
7. Even if OECF funding for power projects is tied (i.e. not immediately available to other sectors such as health and education were the power project to be funded by some other means), for economic analysis the opportunity cost of capital should still be taken at the SDR (10% as assumed here) even though the actual financial costs are significantly less.

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