

Incremental Cost Analysis

1. Broad Development Goals

India's power sector has a total installed generation capacity of 93 GW, of which almost two-thirds are accounted for by coal-fired plants. Estimated maximum demand is in excess of 100 GW, leading to frequent and extensive load shedding. To make up for the shortages in supply and meet growing demand, considerable additions in generation capacity will be required in the coming years.

A major barrier to power sector expansion, however, is the poor financial situation of the SEBs and the limited opportunities for private sector participation. Therefore, the GOI has taken steps to improve the financial health of the SEBs and open the sector to IPPs and outside investors. The preferred policy for private sector entry is to combine engineering, procurement and construction (EPC) and contract these services to a single firm.

Another problem besetting the Indian power sector is its strong reliance on thermal, notably coal-fired, generation facilities. Currently, the annual emissions attributable to electric utilities are on the order of 250 million tons of CO₂, 1.6 million tons of SO₂, and 1.8 million tons of NO_x. The World Bank reckons that without a significant reduction in the share of coal-thermal generation, the emissions will increase to 400 million tons of CO₂ (2,5 million tons of SO₂) by 2005.

To reduce the adverse environmental impacts of the power sector, government strategy focuses on developing renewable energy resources (hydropower, wind, solar energy), promoting the switch to cleaner fuels (gas, naphtha), and supporting the use of advanced low-emission generation technologies (gasification, combined cycle, high boiler efficiency).

In Rajasthan the problems facing the power sector resemble those experienced on the national level. The total capacity that can be dispatched in Rajasthan is 1.85 GW, of which 1.6 GW are available on peak, with coal-thermal facilities providing 1 GW. This is considerably less than the estimated maximum demand of 3.8 GW. As a result, both in on-peak and off-peak periods, Rajasthan has to draw on additional supplies from shared facilities and central power stations connected to the northern grid (NREB). Notwithstanding these extra supplies, load shedding has become pervasive. In 1999, the maximum load served was 3.5 GW, while 0.3 GW or so were lost in shedding. Table 1 provides an overview of the current situation and the projections made by the former Rajasthan State Electricity Board (RSEB), which has been unbundled in a generation company (RVUN), a transmission company (RVPN) and three distribution companies in July 2000.

The load dispatch is illustrated in Figure 1: Kota and RAPP are run as base-load plants; they will be joined by the first unit of Suratgarh Stage I once it is fully operational. Other plants located in Rajasthan (mainly hydro) are used to shave peaks. The remainder of the load is met through withdrawals from the NREB.

Table 1: Actual and Predicted Generation Capacity and Load in Rajasthan (MW)

Year	1999	2003	2007
Rajasthan			
Installed¹⁾			
Kota Thermal (RSEB)	850	850	850
Suratgarh Thermal I (RSEB)	250	500	500
Suratgarh Thermal II (RSEB)	0	500	500
Ramgarh Gas (RSEB)	38	38	109
Mahi Hydro (RSEB)	140	140	140
Chambal Hydro (Shared)	193	193	193
RAPP Nuclear (NPC)	344	388	388
NAPS Nuclear (NPC)	42	42	42
Total Installed	1857	2651	2722
Peaking Capability	1600	2350	2450
Firm BaseLoad	1250	1900	2000
Outside Shares			
Satpura Thermal	125	125	125
BBMB ²⁾ Hydro	639	639	639
Total Rajasthan			
Peaking Capability (net of purchases)	2100	2900	3000
Firm Base Load (net of purchases)	1650	2300	2400
Max. Load	3500	4620	6130
Min. Load	2050	2710	3590
Peaking Deficit	-1400	-1720	-3130
Base Load Deficit	-400	-410	-1190
Purchases⁴⁾			
NTPC Thermal	673	750	1039
NHPC Hydro	127	330	495
Special Allocation ³⁾	700	0	0
<i>Total</i>	1500	1080	1534
<i>Total net of Hydro, GT and Special Allocation</i>	453	500	548
IPP			
Dholpur Combined Cycle ³⁾	0	0	0
Barsingsar Lignite ³⁾	0	0	0
Small Liquid Fuel ³⁾	0	0	0
<i>Total IPP</i>	0	0	0

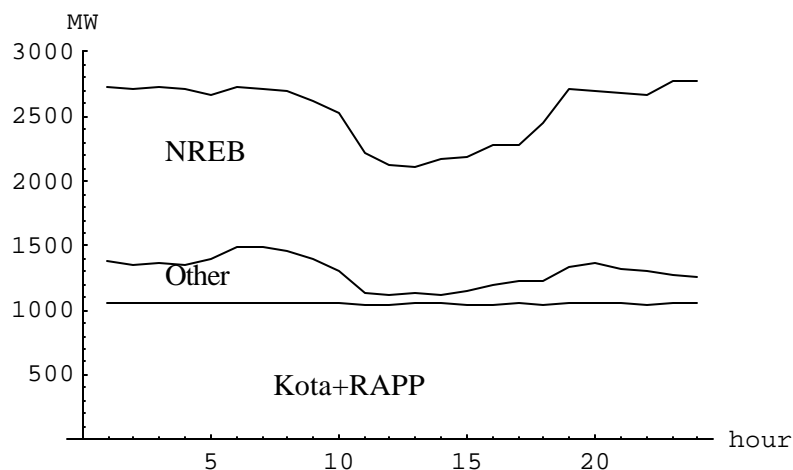
1) Units installed in Rajasthan and dispatched by RSEB, excluding mini hydro plants not connected to the main grid, ISCC Mathania, and wind parks. Peaking capability according to estimates provided by dispatch center.

2) Bhakra Beas Management Board; 3) tentative figures

4) Based on installed capacity, excluding purchases from non-RSEB plant located/dispatched in Rajasthan.

Source: RSEB and mission estimates

Figure 1: Rajasthan Hourly Loads and NREB Withdrawals on October 27, 1999



Source: RSEB

In order to redress the growing imbalances in the power sector, the GOR has launched a number of reforms designed to stabilize the financial condition of RSEB (e.g. through higher tariffs), attract private investors (e.g. IPPs), and promote the use of renewable energy sources.

2. Baseline

Rajasthan's objectives for power sector development are to rapidly increase supply at least cost, unbundle the incumbent utility while encouraging private sector participation and competition, and support the use of "clean" fuels and/or "clean" generation technologies.

As is shown in Table 1, the generation capacity that, according to RSEB estimates, will be available for supplementing the load generated (dispatched) in Rajasthan will not be sufficient to meet the deficit in base load. Hence, investments in new generation facilities will be needed to close the gap.

Solar and wind energy aside, the strategic choices are:

- to increase the reliance on electricity imports
- to add generation capacity using imported coal
- to build lignite-based mine-head power plants
- to embark on liquid fuel based power projects (naphtha, LNG)
- to develop hydropower resources.

Hydropower development is confined to multi-purpose projects (with irrigation needs governing the reservoir management) and to small-scale run-of-river schemes. Neither option is commercially attractive; nor would they add sizable base load capacity.

As regards new base load capacity, the least-capital-cost option would be to extend existing facilities. The scope for this route is narrow though. The only committed

extension project is Suratgarh Stage II (2 x 250 MW), which will use imported low-grade coal.

The private sector, on the other hand, is expected to exploit the potential for new lignite- and liquid fuel-based projects. IPP ventures considered in the 10th Plan for 2002/03 - 2006/07 would add 1.7 GW. So far, however, large-scale investments by IPPs have not been committed. The most prominent project proposals under negotiation are the Dholpur CC plant (702 MW naphtha-based) and the Barsingsar Lignite plant (2 x 250 MW).

In the case of Barsingsar, the dispute over the project's capital costs, which needs to be settled for financial closure, and the uncertainty surrounding the contractual arrangements for fuel supply have led to considerable delays.

Unlike Barsingsar, Dholpur has been cleared by CEA and MOE, but the recent increase in the international price of crude and the concomitant rise in the cost of naphtha have significantly reduced the short-term commercial prospects of liquid fuel based IPP projects: Typically, naphtha is a feedstock for petrochemicals and fertilizers, but the GOI also endorsed the use of naphtha as a fuel in power generation by the end of the 9th Plan.¹ The decision was taken in 1998 when the price of naphtha, like that of crude oil, was depressed. With the sharp rise in oil prices during 1999, however, the era of cheap naphtha came to a sudden end (see also Figure 2 below).

In sum, there are three types of projects in Rajasthan's power sector (or a mix thereof) that would qualify as a "baseline" representing future investment in base load generation capacity without taking into account global environmental considerations about greenhouse gas emissions:

- Suratgarh Stage II,
- a naphtha/LNG-based combined cycle plant,
- a lignite-fired power station.

Table 2 summarizes the key parameters of the projects in question. The data pertaining to Suratgarh are CEA estimates updated by RSEB. The data on Barsingsar are mission estimates. The comparator naphtha-fired CC plant is a notional design matching the expected performance (e.g. fuel consumption) of ISCC (Fichtner, September 1999). The same applies to a notional stand-alone solar-thermal plant, which is also considered in Table 2. Costs estimates are expressed in mid-2001 Indian Rs, with economic prices - net of taxes, duties and environmental effects - used as a benchmark. Foreign costs (US\$) are valued in terms of the official rate of exchange (46.45 Rs/US\$ as of May 2001). No shadow pricing is applied to local inputs.

¹ Currently, India's annual naphtha consumption is estimated at 6.6 million tonnes, of which 5.7 million tonnes are accounted for by non-fuel uses. If all naphtha-based projects considered for power sector expansion were to come on stream (which is unlikely), this would create an extra demand of more than 10 million tonnes by 2007.

Table 2: Overview of ISCC Mathania and Alternative Power Projects

	ISCC Mathania	Naphtha or LNG-based Combined Cycle	Suratgarh Thermal Stage II	Barsingsar Lignite	Stand-Alone Solar-Thermal
Acronym	ISCC	CC	STII	BL	SAST
Ownership	RSPCL	IPP	RSEB	IPP	RSPCL
Status	cleared by CEA	not applicable	cleared by CEA and committed	no clearance by CEA	not applicable
Gross Power (MW)	122.5	102.6	2x250	2x250	30
Investment Costs (Rs million)	7,469.3	3,612.4	17,875.5	24,965.0	4,595.0
Rate of Exchange as of May 2001 (Rs/US\$)	46.45	46.45	46.45	46.45	46.45
Construction Period (years)	4	4	4	4	4
Disbursement of Investment during Construction (Ratios)	0.15 : 0.35: 0.35 : 0.15	0.15 : 0.35: 0.35 : 0.15	0.15 : 0.35: 0.35 : 0.15	0.15 : 0.35: 0.35 : 0.15	0.15 : 0.35: 0.35 : 0.15
Specific Investm. Cost (Rs/kW)	60,974	35,209	35,751	49,930	153,167
Energy Sent Out (GWh/year)	815	757	3200	3200	62.5
Solar Share (GWh/year)	63	0	0	0	62.5
Operating Period	25 years	25 years	25 years	25 years	25 years
Annual O&M (% of Inv.Costs)	2.5	2.5	2.5	2.5	2.5
Fuel	Naphtha	Naphtha	Coal	Lignite	Naphtha
Heating Value (MJ/kg)	42.7	42.7	16.2	11.3	42.7
Annual Fuel Consumption ('000 tons)	128	129	2080	3200	1
CO2 Emissions (kg per kg fuel)	3.31	3.31	1.86	1.21	3.31
Fuel	LNG	LNG			LNG
Annual Fuel Consumption (Mio MMBTU)	5.169	5.220			0.041
CO2 Emissions (kg/MMBTU)	52.4	52.4			52.4
Fuel Costs	Dependent on crude price	Dependent on crude price	2,000 Rs/ton	800 Rs/ton	Dependent on crude price

Source: mission estimates, RSEB, Fichtner (1999, 2001)

3. GEF Alternative

The proposed alternative to any baseline candidate would add 122,5 MW of generation capacity provided by an ISCC plant run on solar and thermal heat to generate base load, with an expected annual net output of 815 GWh, of which 63 GWh (7.7%) are attributable to the solar component (see Table 2).

The choice of the barebones project design was guided by the following considerations and criteria:

- cost effectiveness
- utility-scale size of plant
- commercial operating experience with the solar component (parabolic trough technology)
- potential for economies of scale through innovation and mass production
- application of advanced CC technology
- use of low-emission fossil fuel

The project's detailed layout (e.g. solar storage, auxiliary firing) is left to the bidders for an EPC cum five-year O&M contract. The plant will be owned by RSPCL. Commercial operation of the plant will be ensured through a PPA with RSEB (or its successor organization responsible for bulk power transactions) and market-based fuel and water supply arrangements.

The project meets the GEF Operational Program Objective Number 7 of reducing the long-term costs of low greenhouse-gas emitting energy technologies. It focuses on an operationally proven and potentially competitive technology that is likely to benefit from scale economies through additional operational experience, replication and the concomitant reduction of perceived project and technology risks. It involves the use of an advanced power generation technology (combined cycle). And it may contribute to the development of an Indian solar-thermal manufacturing industry.

An additional domestic benefit of the GEF alternative is that it reduces the level of emissions polluting the local environment (SO₂ etc.) below that associated with an equivalent thermal plant.

4. Scope of Analysis

Given the small size of the proposed GEF alternative relative to the overall needs for additional base load capacity, and keeping in mind that to date only 500 MW of new generation capacity are committed by RSEB while the status of proposed IPP projects remains uncertain, the GEF alternative is unlikely to crowd out any particular project considered in Rajasthan's expansion plan. Nor would it call for major adjustments in power system operation (unit commitment, dispatch). Therefore, the analysis can be confined to a plant-by-plant comparison of ISCC with an equivalent conventional power station (project).² In defining the baseline, the key question is which equivalent project

²The benchmark for equivalence is the annual energy sent out by ISCC.

would be implemented in lieu of the GEF alternative if incremental cost finance were not available.

LRAC and CO₂ Emissions

An obvious criterion for selecting the baseline project would be that of least (domestic) cost, measured in terms of long-run average - or lifetime average - costs of electricity generation. As annual fuel consumption (F), fixed annual expenses on O&M (FOM), and annual net output (X) are assumed to be constant over time for any project variant considered, and since unit fuel cost, which may vary over time, can be converted into a constant annual equivalent (P), long-run average costs (LRAC) of electricity generation can be expressed as

$$(1) \quad LRAC = \frac{INV * CRF}{X} + \frac{FOM + P * F}{X}$$

where CRF denotes the (discrete-time) capital recovery factor. INV stands for the value of investment at the date of commissioning (compounded disbursements). Since the plant is operated for 25 years, the capital recovery factor works out at

$$(2) \quad CRF = \frac{i}{1 - (1 + i)^{-25}} \quad (i = \text{discount rate}),$$

and the present value of equivalent lifetime costs that can be imputed to a baseline project displaced by ISCC, say BL, is given by

$$(3) \quad EPVC_{BL} = \frac{Y * LRAC_{BL}}{CRF}$$

where Y denotes the annual net output of ISCC.

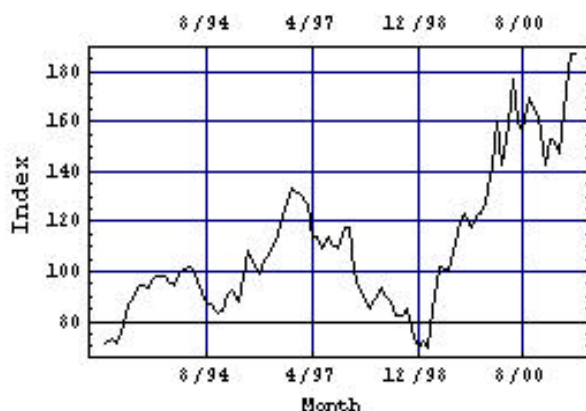
In any case, the ranking of potential baseline projects crucially depends on the discount rate and the (economic) costs imputed to fossil fuels. As for the discount rate, an annual inflation-adjusted (real) rate of 12% is applied, assuming that the required nominal return on commercially attractive power sector projects is 15% relative to an inflation rate of 2.7% a year.

Regarding the fuel costs, it is assumed that the landed costs of low-grade Indian coal amount to 2000 Rs/ton, of which 1150 Rs/ton are accounted for by transport and handling; the mine-head price of lignite from Rajasthan deposits is estimated at 800 Rs/ton.

The price of naphtha showed a marked upward trend since 1999 (see Figure 2 below). The increase was largely due to the hike in crude oil prices, which started in March 1999 when OPEC agreed to production cutbacks after oil prices had dropped to their lowest level since 1991; but the rise also reflected the removal of price controls in

India's petroleum product markets.³ As a result, in late 1999 naphtha was sold at 11,800 Rs/ton (ex-storage port refinery) plus freight, compared to 6,830 Rs/ton charged in 1998. The price of naphtha has since remained at a high level so that RSPCL commissioned a study on alternative fuel options for ISCC Mathania. The report submitted by Crisil Advisory Services (CAS)⁴ found that Liquefied Natural Gas (LNG) would be a viable alternative to naphtha.

Figure 2: Index of Monthly Naphtha Spot Prices, Singapore, January 1994 - June 2001



The fuel price projections used by the CAS-report are based on parameter estimates for regressions on the price of crude oil (Arab Light, 1975-2000) detailed in Table 3. In addition, the CAS-report assumes that upon commissioning of ISCC the price of crude is 21 US\$/bbl and rises at 1.96% a year in real terms thereafter. We assume that the initial price of crude is 22 \$/bbl. At a 12% discount rate, this is equivalent to a constant annual crude price of 25.27 \$/bbl, corresponding to constant annual landed costs of 12,449 Rs/t (291 Rs/GJ) for Naphtha and 239 Rs/MMBTU (227 Rs/GJ) for gas.⁵

Table 3: Cost Formula for Naphtha and LNG

	Naphtha (US\$/t)	LNG (US\$/MMBTU)
FOB	$(0.8997 \cdot \text{Crude}[\$/\text{bbl}] + 5.349) \cdot 8.5$	$0.1485 \cdot \text{Crude}[\$/\text{bbl}] + 5.340$
Ocean losses etc.	6% of FOB	
Shipping	15	0.4
Re-gasification		0.6

Source: CAS (2001)

Table 4 highlights the advantage that gas has over naphtha in terms of LRAC and CO₂ emissions. The table also shows that Barsingsar Lignite (BL), which is the least-cost baseline option, scores worst on CO₂. SAST would have the highest generation costs and the lowest level of emissions.

³ Deregulation affecting naphtha, fuel- and diesel oil kicked off in April 1998.

⁴ Detailed Feasibility Report, March 21 2001

⁵ Gas is priced per million BTU (MMBTU).

Table 4: LRAC and CO₂ Emissions

	LRAC (Rs/kWh)			CO ₂ -Emissions (million tons) ¹⁾
	Discount Rate 12%	Discount Rate 8%	Discount Rate 6%	
ISCC LNG	3.13	2.74	2.58	6.77
ISCC Naphtha	3.57	3.19	3.03	10.59
CC LNG	2.49	2.30	2.23	7.36
STII	2.28	2.02	1.91	24.63
BL	2.17	1.81	1.65	24.65
SASTLNG	13.09	9.67	8.21	0.70

1) Lifetime emissions (undiscounted)

System Boundary

This report suggests that ISCC be compared with coal/lignite-based power generation rather than with a combined cycle plant run on natural gas or naphtha. On global climate grounds, the use of naphtha/gas in itself has the advantage of lower emissions (when compared with coal or lignite) at the expense of higher fuel and generation costs. Put differently, there is a major trade-off between naphtha/gas (high costs, low emissions) and coal/lignite (low costs, high emissions). Integrating the solar-thermal component into the naphtha/gas-based CC option would reinforce this trade-off by increasing the opportunity costs of CO₂ abatement, particularly when a high discount rate is applied. Hence, it is sensible to define the baseline in terms of a conventional solution based on coal/lignite and to compare it with the integrated use of solar-thermal energy in a naphtha/gas-fired CC plant. Moreover, since the available evidence suggests that LNG is the cheapest fuel option for Mathania, the alternative considered is an ISCC plant run on gas.

Emission Accounting

CO₂, CH₄ and N₂O are the most important anthropogenic greenhouse gas emissions (GHG) resulting from energy use. For the Mathania ISCC project, we have limited the analysis to a comparison of CO₂-emissions from the project as against those that would result from the baseline alternative:

- GHG-emissions other than CO₂ are negligible if we define the project boundary in a narrow sense, i.e. the combustion of fossil fuels in the ISCC vs. the baseline alternative. CO₂ emissions account for almost the entire greenhouse impact of the combustion process, so non-CO₂ emissions can be ignored.
- If the project boundary is extended to the relevant upstream processes, CH₄ plays an important role only in naphtha or natural gas production and transport, in the case of the ISCC, and in coal extraction, in the case of the baseline alternative. N₂O-emissions do not arise to a significant extent for these processes. In fact, the only common fossil fuel electricity generating technology with a relatively high greenhouse contribution from CH₄ or N₂O is a natural gas-fired internal combustion engine.

- While the full cycle approach has the appeal of being theoretically rigorous, its practical application is fraught with problems. Due to lack of accurate, confirmed data for the activities outside the project boundary, the assessment of the emissions in the upstream activities proves difficult and would be very time-consuming. It is estimated, however, that the upstream activities in the case of the baseline alternative will generate more damaging effects in terms of CO₂-equivalents than those upstream processes involved in the case of the ISCC.
- Therefore, simplifying the calculation by considering only the direct CO₂ emissions from combustion represents a conservative approach to the assessment of the benefits in terms of avoided emissions, i.e. the benefits of the ISCC would be higher if the full energy cycle was considered.

5. Incremental Costs

In light of Formula (3), which defines discounted equivalent lifetime costs, the incremental costs of ISCC, say, vis-à-vis BL, can be expressed as

$$(4) \quad IC = PVC_{ISCC} - EPVC_{BL},$$

where PVC_{ISCC} denotes the present value of costs associated with ISCC.

The incremental costs of LNG-based ISCC over the different baseline options and the corresponding unit CO₂ abatement costs are presented in Table 5. The estimates show that incremental costs increase with the amount of emissions avoided by ISCC, and Unit abatement costs are highest for CC Gas and lowest for STII.⁶

Table 5: Overview of Incremental and CO₂ Abatement Costs¹⁾

	Equivalent Present Value of Lifetime Costs (Rs million)	Incremental Costs of ISCC Gas (Rs million)	Lifetime CO ₂ Emissions, undiscounted (million tons)	Unit Costs of CO ₂ Abatement through ISCC Gas (Rs/ton)
	EPVC	IC		
ISCC Gas	20,010	n.a.	6.77	n.a.
ISCC Naphtha ²⁾	22,806	n.a.	10.59	n.a.
CC Gas	15,961	4,094.16	7.36	6,930.6
STII	14,593	5,417.78	24.63	303.3
BL	13,888	6,122.09	24.65	342.4

- 1) 12 % discount rate; incremental costs based on ISCC with gas (LNG).
- 2) Incremental and abatement costs are not applicable since ISCC Naphtha is more expensive and has higher emissions than ISCC Gas.

⁶ It should be kept in mind that the integrated solar-thermal solution has much lower LRAC than a stand-alone solar-thermal plant (see Table 4). Hence, the unit CO₂ abatement costs of an independently operating solar-thermal plant will be considerably higher than is indicated in Table 5: CO₂ abatement through SAST (LNG) would cost 2,887 Rs/t (62.15 \$/t) vs. STII and 2,914 Rs/t (62.73 \$/t) vs. BL.

As is shown in Figure 3, incremental costs decline with a higher discount rate. This is because a higher discount rate reduces the present value of the cost differentials between (expensive) LNG and (cheap) coal/lignite. Moreover, for discount rates up to 13.38% incremental costs of gas-based ISCC vs. STII are lower than those vs. BL; beyond this threshold, the opposite is the case. The fact that the incremental costs of ISCC vs. lignite (BL) decline faster than those vs. coal (STII) is attributable to the cost advantage that lignite has over coal.

Figure 3: Incremental Costs (Rs million) of Gas-Based IISCC as a Function of the Discount Rate

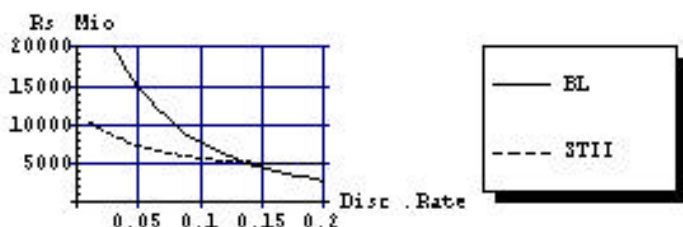
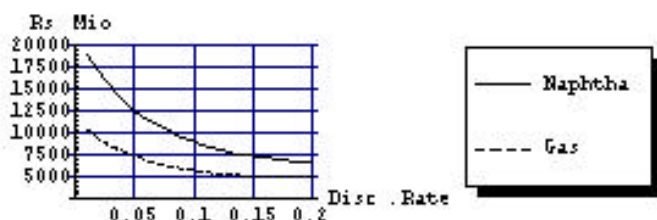


Figure 4 illustrates the fact that the incremental costs of naphtha-fired ISCC exceed those of the LNG-fired ISCC. Again, a higher discount rate lowers this differential because it reduces the present value of the cost advantage that gas has over naphtha.

Figure 4: Incremental Costs (Rs million) of Naphtha - and Gas-Fired ISCC vs. STII



This report suggests that in the final analysis the baseline for estimating the incremental costs of gas-fired ISCC should be Suratgarh Stage II rather than the Barsingsar Lignite project. Unlike Barsingsar, the extension of the coal-thermal plant at Suratgarh is a financially viable course of action that has been cleared by CEA and MOE, and to which RSEB (or its successor) is committed.

Table 6 provides an overview of the domestic and global benefits of the GEF alternative and its estimated incremental costs using the coal-thermal power plant (Suratgarh II) as baseline. Incremental costs do not include expenditures on project preparation, technical assistance and capacity building.

Briefly put, estimated incremental costs amount to US\$ 116.64 million (Rs 5418 million). In return, this will avoid the release of almost 18 million (metric) tons of CO₂ over a period of 25 years, at a cost of US\$ 6.52 (Rs 303) per ton of CO₂. It will also contribute to reducing the risks and costs of similar projects along the ISCC route. In addition to global environmental benefits, the GEF alternative would considerably diminish the emission of pollutants affecting the ambient environment.

It is also worth noting that 26% of the incremental costs are accounted for by fuel. This highlights the fact that a large amount of the emissions avoided by the GEF alternative can be ascribed to LNG, which is comparatively costly but environmentally less harmful than the baseline-fuel coal. Nevertheless, the use of gas in an integrated solar-thermal combined-cycle plant lowers unit costs of CO₂ abatement below the level of an equivalent stand-alone solar-thermal power station.

Table 6: Incremental Cost Matrix with Coal-Thermal Power Generation as Baseline

	Baseline	Alternative	Increment
Domestic Benefits	815 GWh/year generated by a coal-fired power plant (Suratharh Stage II).	815 GWh/year sent out by an ISCC plant run on gas (122.5 MW gross power). Lower level of emissions polluting the local environment. Transfer of know-how; training of local staff operating the ISCC; opportunities for local manufacturers to gain experience with ISCC.	0 Reduction in the release of sulfur, nitrogen and particulates. Capacity and institution building; integration of solar-thermal energy in electricity supply system; improved prospects for follow-on projects with local participation.
Global Environmental Benefits		Virtually no GHG emissions associated with solar component. Significantly reduced GHG emissions through the use of LNG.	Avoided release of 17.8 million tons of CO ₂ during a 25-year period. About 17 million tons of avoided CO ₂ emissions attributable to the use of gas. Contribution to potential cost reductions in ISCC, notably with respect to its solar-thermal component.
Present Value of Costs¹⁾ (Rs million)			
	5,425.77	8,901.76	3,475.98
Investment	856.97	1,405.99	549.01
Fixed O&M	8,309.81	9,702.59	1,392.78
Fuel			
Total	14,592.60	20,010.34	5,417.78
Total US\$ million ²⁾	314.15	430.79	116.64

1) based on a discount rate of 12%

2) 1 US\$ = Rs 46.45