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Relative Environment Economics of Natural Gas and other Fossil Fuels for Power Generation and Policy Options for India

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Executive Summary

In the recent years, several factors constraining India's power generation policies and targets have emerged. Among all the constraints, availability of fuel has been identified as the major factor that affects the development of power generation capacity in the country. More than half the existing generation capacity of the country is based on coal and this dependence on coal is likely to continue in the future given the existing capacity expansion plans for the Twelfth Five Year Plan (2012-17). However, future decisions on additions to power generation capacity should be taken keeping in view not just the financial cost of generating power but also the environmental implications, availability and cost of fuel for power generation and the long term feasibility of the choices made.

This report focuses on four fuel options for the Indian power sector that are expected to meet a substantial chunk of power demand – domestic coal , imported coal, domestic gas and Liquefied Natural Gas (LNG).

Figure ES 1 summarizes the methodology adopted for the study.

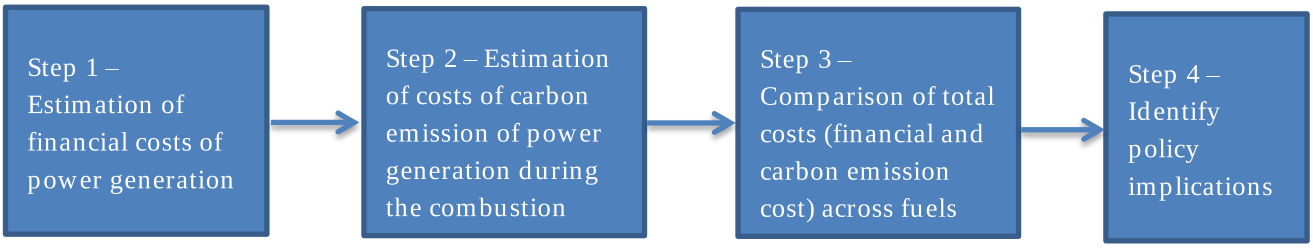


Figure ES1: Methodology and approach

This report compares the cost of power generation for coal based plants with that of plants based on natural gas across different locations in the country. The locations have been selected with the objective of having a varied spatial mix so as to account for transportation costs involved in transferring the fuel to power plants. The price of domestic coal consumed in India varies according to the grade of coal. For the purpose of computing the prices of domestic coal at various locations, an average of prices for coal grades 9,10,11,12 has been considered for the current analysis. On the other hand, in case of imported coal, the average Free on Board (fob) price of coal imported from Indonesia for the period July 2011 to June 2012 of US$ 112/ tonne has been assumed in the base case. Further, in the base case, price of domestic gas is assumed to be US$ 4.2/ million British thermal units (mBtu) and that of LNG in the Base Case is assumed to be US$ 9 mBtu[1] (fob price), which is the long-term contract price of Qatar's Rasgas. Although the actual price of domestic natural gas varies from US$3.5 / mBtu to 5.7/ mBtu, depending on the source, the largest supply of natural gas in the country is from two sources – the APM fields and the D6 block in KG basin, both of which are priced at US$4.2/ mBtu.

Financial cost of domestic coal based power generation is lower than that of natural gas. The cost of coal based power varies from Rs. 2.52/ kWh (kilowatt hour) in locations such as Bilaspur and Talcher that are close to coal mines to Rs. 3.85/ kWh in far off areas like Kochi. In case of natural gas the cost varied from Rs 3.55/ kWh in Vishakhapatnam to Rs. 3.97/ kWh in Agartala. For imported fuels, the cost of power from imported coal varies from Rs.

[1] Based on discussions with experts

4.93/ kWh in Vishakhapatnam to Rs 5.75/ kWh in Agartala whereas that of imported gas (LNG) varies from Rs. 6.12/ kWh to Rs. 6.38/ kWh (Table ES1).

Table ES1: Summary of financial cost of power generation

Plant Locations	Fuel Options			
	Domestic Coal	Imported Coal	Domestic Gas	LNG
Delhi	3.38	5.47	3.67	6.38
Bilaspur	2.52	5.35	3.91	6.36
Vadodara	3.18	5.16	3.60	6.31
Vishakapatnam	2.86	4.93	3.55	6.12
Kochi	3.85	5.10	3.97	6.12
Talcher	2.52	4.98	3.91	6.33
Dhanbad	2.68	5.09	3.95	6.38
Agartala	3.73	5.75	3.97	6.38
Nagpur	2.88	5.35	3.63	6.28

As can be noted, domestic coal based power generation continues to remain across all sites and variations in the cost of transportation are also not significant enough to change the cross-region comparison.

However, in view of the concerns related to the impact of carbon on the environment, it is pertinent to examine the relative carbon costs of various fuel options for power generation. It should be noted that in this study, the environmental cost of power generation incorporates only the social cost of carbon during combustion and flaring processes. It does not internalize the other environmental and social and economic cost of power generation such as land deterioration, rehabilitation, water pollution, etc.

This report takes into account the cost of carbon emitted in the process of power generation. The total carbon impact of power generation is defined as the sum of emissions due to mining and emissions due to combustion. In case of imported coal and LNG, however, emissions due to mining are not included as these take place in the exporting country and not in India. The total carbon impact of coal based power generation has been found to be nearly twice that of gas based generation. The impact of carbon on the total cost of power generation is then calculated using a per tonne carbon price of US$ 30. This has been assumed as the base price for carbon. As per the findings of the Stern Review if the target Green House Gas (GHG) emissions were to be maintained between 450-550 ppm CO_2e, then the social cost of carbon would be between US$ 25-30/ tonne of CO_2 e (Stern, 2007).

The findings are summarised in Table ES 2.

Table ES2: Summary of financial and carbon cost of power generation (at a carbon price of US$ 30/ tCO_2)(Rs./ kWh)

Plant Locations	Fuel Options			
	Domestic Coal	Imported Coal	Domestic Gas	LNG
Delhi	4.97	7.02	4.41	7.11
Bilaspur	4.11	6.91	4.65	7.09
Vadodara	4.76	6.72	4.34	7.04
Vishakhapatnam	4.45	6.48	4.29	6.86
Kochi	5.44	6.65	4.72	6.86
Talcher	4.11	6.53	4.65	7.07
Dhanbad	4.26	6.64	4.70	7.11
Agartala	5.32	7.30	4.72	7.11
Nagpur	4.47	6.90	4.38	7.02

Here, domestic coal is a cheaper source of power generation in sites like Talcher and Bilaspur that are located close to coal mines. In other regions domestic gas is the least expensive option. The difference between domestic coal and gas based power generation is particularly evident in distant locations like Agartala. Among the imported fuels however, coal is a less expensive option as compared to LNG. The only location where the cost of LNG based power generation is less than that of imported coal is Agartala primarily on account of the distance over which coal needs to be transported.

While the foregoing analysis does examine the relative costs of power generation across the different locations in the country, issues of fuel availability, technological constraints in using imported coal and the changing international coal and gas markets also need to be considered while planning for meeting the country's growing energy requirements.

Key factors that will affect the future course of the country's power sector policy are price and availability of domestic fuel sources and the changing nature of the discourse on climate change.

India's domestic coal reserves are insufficient to meet the domestic requirement (Batra & Chand, 2011). Further, there are significant complexities in the international coal markets as well. Australia, India's second largest source of coal imports has already imposed a carbon tax on carbon intensive industries and Indonesia is considering banning exports of coal with lower gross calorific values (GCV) and imposing a tax of 25% on coal exports. A decline is also being witnessed in the domestic production of natural gas from the D6 fields in the KG basin operated by Reliance Industries Limited (RIL). The production of natural gas in 2011-12 was 47.5 billion cubic meters (BCM), a decline from 52.2 bcm during the previous year. The projected availability of gas over the next three years is also expected to be below 50 bcm. As a result, the gas allocated to power sector has declined and power generation plants that were set up keeping in view the availability of gas from the D6 block are now either stranded or operating below normal capacity. The fact that the country's dependence on imports to meet domestic energy needs will increase significantly in the medium to long term future is inescapable.

A related issue therefore is the prices at which these fuels will be available. Domestic pricing of coal has recently been changed from the Useful Heat Value (UHV) based classification to a GCV based mechanism. In the period from 2004 to 2011, the domestic prices of coal were revised three times and as a result the price of domestic coal has increased by nearly 40% (Lok Sabha, 2011). The international coal prices have declined in the past two years. Notwithstanding this decline, the global demand for coal is rising driven primarily by the rising import demand from emerging countries like China and India. The long term implications of rising demand from these countries and the falling demand from OECD countries will depend on the volume of trade. In case of natural gas however, the international prices are already responding to the increased availability of shale gas in USA where the prices have now declined to nearly US$ 3/ mBtu. However, this is yet to impact the prices of imported LNG in Asia where gas continues to be imported at rates between US$ 9 and 13/ mBtu varying depending on the transportation costs and nature of contracts. The extent to which rising gas production in USA will impact the spare production of gas in Asian exporters and therefore the Asian prices will become clear in the near to mid-term future. In case of domestic natural gas as well, it is unlikely that a price of US$ 4.2/ mBtu that exists currently can be maintained as the pressure to review the current pricing mechanism and aligning it with international prices is increasing.

Another factor that will play a significant role in determining the country's energy policy is the long-term goal of reducing carbon emissions to address the rising concerns of climate change. Natural gas provides an alternative to coal for power generation in India. On the domestic front, the National Action Plan on Climate Change (NAPCC) recommends adoption of natural gas based power plants as an option to mitigate GHG emissions. This has also been recognized as a lower emission intensive option in the Second National Communication to the United Nation Framework Convention on Climate Change (MoEF, 2012).

Recommendations and way forward

The shortage of domestic coal and gas and its impact on power production in the country has been widely discussed in the recent months. To meet the requirements of existing and planned power generation capacity, alternative fuel sources will have to be actively considered. While sources such as renewables and nuclear power do provide long term solutions, the current capacity and the planned additions based on these fuels will not be sufficient in meeting the growing power requirements in the near to medium term. High dependence on thermal based power generation is likely to continue. In the capacity addition envisaged in the 12th Five Year Plan, nearly 64,000 MW of the total planned capacity of 94,000 MW will be based on thermal power. Hence, imported LNG, although currently more expensive, needs to be developed as the fuel for meeting the electricity requirements of the country. A comprehensive plan for import of LNG needs to be developed wherein infrastructure related to shipping, regasification, storage and pipeline facilities need to be created proactively.

Introduction

Background of the Indian Power Sector

Electricity is a crucial input for maintaining the growth trajectory of India. Power consumption in the country has increased substantially in the recent years and this trend is estimated to continue. The demand for electricity has increased at a rate of 6.27% in the past two decades.[2] The 17th Electrical Power Survey of the Central Electricity Authority (CEA) has projected an increase of 43.7% and 97.6 % in energy demand by 2016-17 and 2021-22 respectively over that in 2011-12.

However, the growth in supply of power has not been able to keep pace with the growing demand. In FY 2011-12, the energy and peak deficits in the country were 11.1% and 12.1% respectively (CEA, 2012). To be able to meet this growing demand there is a need to augment generation capacity and to achieve the capacity addition targets set in the Five Year Plans. However, there have been consistent shortfalls in every plan period in the capacity addition vis-à-vis targets (Planning Commission, 2011a) (Figure 1).

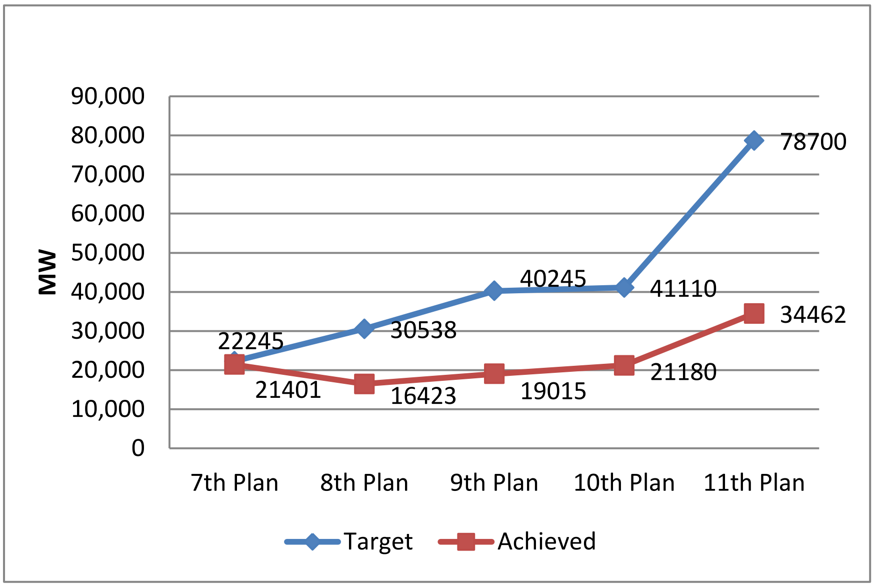


Figure 1: Shortfall in Capacity Addition

Source: Planning Commission (2011a)

[2] The two decade period implies 1989-90 to 2009-10

Installed Capacity

The installed power generation capacity in India is dominated by coal based generation followed by hydel and renewable based generation. Natural gas accounts for 9% of the total generation capacity (Figure 2) (CEA, 2012).

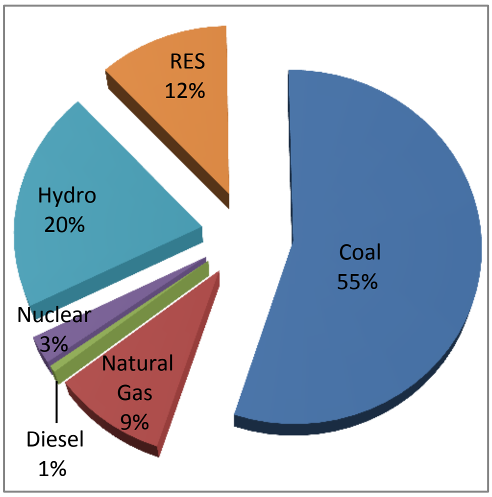


Figure 2: Installed generation capacity

Source: CEA (2012)

Over time, the share of coal in the generation mix has increased. In India, steam/ non-coking coal is primarily used for the purpose of power generation.

The dominance of coal-based power generation in the country is expected to continue in the near future. The Report of the Working Group on Power for the Twelfth Plan estimates that in the base case scenario coal based projects would account for 63,000 megawatts (MW) of the total 94,300 MW generation capacity planned for the Twelfth Plan period (MoP, 2012), which amounts to approximately 82 % of the planned installed capacity.

The consumption of natural gas in power generation has increased from around 12 billion cubic metres (BCM) in 2005-06 to 27 BCM in 2010-11. In India, natural gas is primarily used in fertilizer, power generation, LPG and the petrochemical sectors (Figure 3).

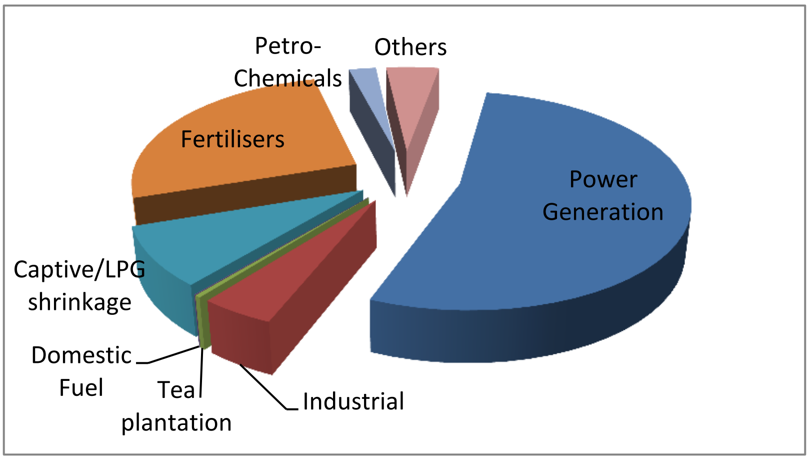


Figure 3: Sector-wise consumption of natural gas in 2010-11

Source: MoPNG (2012)

Fuel availability

Ensuring fuel supplies to power plants is becoming increasingly constrained. This is evident in the problems being faced in ensuring coal supplies to power generation plants. India is becoming increasingly dependent on imports to meet the demands. The country's dependence on imported coal has increased from 9% in 2006-07 to 15% in 2010-11. As per the estimates of the Working Group for Coal for the Twelfth Five Year Plan the share of imports will increase further to 27% by the end of the Twelfth Five Year plan in the business as usual (BaU) scenario and to 19% in the optimistic scenario (MoC, 2011).

Import of coal to meet shortfall of domestic production is inevitable. However, the entire shortfall of domestic coal cannot be met by imports due to technical limitations with respect to the blending levels of the existing boilers (which is currently around 15%). In order to meet the entire power generation requirement estimated as per the Twelfth Plan, 842 Million Metric Tonnes (MMT) of coal will be needed out of which only around 54 MMT has been estimated to be imported. However, in the base case scenario, there still shall be a coal shortfall of around 238 MMT for power generation.[3]

In case of natural gas too, dependence on imports is rising. Although domestic supply increased substantially as the production from the D6 block in the Krishna Godavari basin operated by RIL and Niko Resources began in 2009-10, the fall in production from these blocks beginning 2011 has reduced the availability of domestic gas substantially. This has led to an increase in dependence on imports to meet the domestic requirements.

As availability of domestic coal and domestic gas have been severely constrained, it is necessary to examine the relative costs of power generation based on different fuels.

This report attempts to draw a comparison between the costs of power generation based on two primary fuels – coal and natural gas. Historically, coal based power, especially domestic coal has been found to be financially more competitive than gas based generation. However, the growing concerns of climate change and carbon emissions from coal based power generation and chronic coal shortages also warrant an examination of the relative carbon emissions cost of power generation using both coal and natural gas and inclusion of these (carbon) costs into the traditional financial cost calculations.

[3] The import quantum is based on the blend ratio of domestic and imported coal that is feasible as per the existing boiler characteristics.

Financial Cost Estimation

This chapter focuses on the financial cost of power generation in India based on each fuel source. The methodology adopted and assumptions made for arriving at the financial costs of power generation are discussed in detail.

Methodology and Assumptions

Calculation of financial cost of power generation involves assuming certain power plant locations followed by an estimation of cost of generation, which in turn is based on capital costs, operations and maintenance (O&M) costs and the fuel costs.

Locations considered for power generation

For the purpose of this study, five representative power plant stations have been considered across the five regions of the country viz. north, south, east, west and north-east. An assessment of the cost of power generation from the following fuel sources has been carried out -

I. Domestic Coal

II. Imported Coal

III. Domestic Natural Gas

IV. Imported Liquefied Natural Gas (LNG)

For coal based power plants, the nearest coal field locations have been identified and the respective distance from these fields have been assumed for the purpose of computation of transportation costs. For gas based power stations, in case of domestic gas, the closest ports and pipeline network have been assumed. In case of LNG, the LNG terminals and pipelines closest to the respective power plants have been assumed.

The details of the fuel linkages of the power stations under consideration are provided in Table 1 and Figure 4.

Table 1: Locations of power plants and fuel linkages

Region	Power Plant Location	Power Plant	Domestic Coal	Imported Coal	Domestic Natural Gas	Liquefied Natural Gas
North	Delhi	Badarpur Thermal Power Station	Central Coal Fields, Karanpura, Jharkhand (Ranchi)	Kandla Port	Western offshore fields	Dahej
North	Chhattisgarh	Korba Thermal Power Station	Korba (pithead power plant)	Kolkata Port	Kakinada, AP	Gangavaram*

Region	Power Plant Location	Power Plant	Domestic Coal	Imported Coal	Domestic Natural Gas	Liquefied Natural Gas
West	Gujarat	Gandhar Gas Power Station	Western Coal Fields Ltd	Kandla Port	Gandhar Gas field, Gujarat	Dahej
South	Andhra Pradesh	Simadri Thermal Power Station	Talcher Coal fields, Angul district (Pithead)	Vishakapatnam Port	Kakinada, AP	Gangavaram
South	Kerala	Kayamkulam Gas Power Station	Talcher Coal fields, Angul district (Pithead),	Tuticorin Port	Kakinada, AP	Kochi
East	Orissa	Talcher Kaniha Power Plant	Talcher Coal fields, Angul district (Pithead)	Paradip Port	Kakinada, AP	Gangavaram
North	Jharkhand	Maithon Gas Power Station	Central Coal Fields, Karanpura,	Kolkata Port	Kakinada, AP	Gangavaram
North East	Tripura	Agartala Gas Power Station	ECL Raniganj,	Kolkata Port	Kakinada, AP	Gangavaram
West	Maharashtra	Kaparkheda thermal power station	Western Coal Fields, Maharashtra	Paradip Port	Western offshore fields	Dahej

*The LNG terminal was been proposed by Petronet LNG at the Gangavaram Port in May 2012 (Petronet LNG, 2012)

The assumed distance of the power plants from the respective coal fields and gas terminals/ pipelines is provided in Table 2.

Table 2: Distance of power plants from coal fields and gas terminals (Distance in Km)

Region	Power Plant Location	Power Plant	Domestic Coal	Imported Coal	Domestic Natural Gas	Liquefied Natural Gas
North	Delhi	Badarpur Thermal Power Station	1162	1096	1170	1073
North	Chhattisgarh	Korba Thermal Power Station	0	856	813	673
West	Gujarat	Gandhar Gas Power Station	817	478	0	45
South	Andhra Pradesh	Simadri Thermal Power Station	450	0	159	0
South	Kerala	Kayamkulam Gas Power Station	1944	304	462	0
East	Orissa	Talcher Kaniha Power Plant	0	99	678	524
North	Jharkhand	Maithon Gas Power Station	167	281	1102	948
North East	Tripura	Agartala Gas Power Station	1619	1680	1622	1468
West	Maharashtra	Kaparkheda Thermal Power Station	462	837	822	677

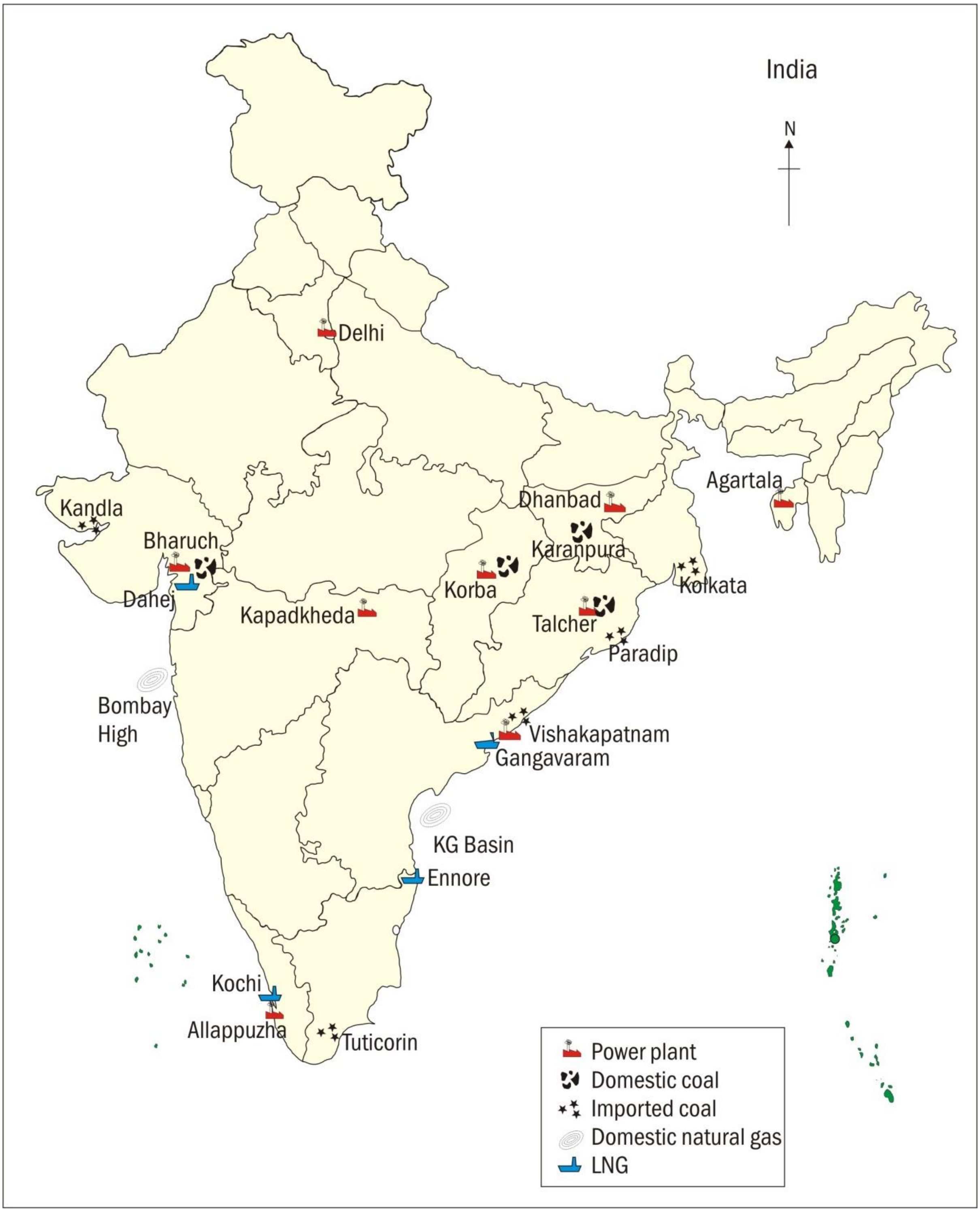


Figure 4 Map: Locations of power plants and sources of fuel

Approach and assumptions

Financial cost estimation

In order to examine the feasibility of power generation in terms of financial cost, a base case scenario with a number of parameters has been arrived at. The financial cost of generation consists of three parts, namely:

- Fixed cost per unit
- Operating and maintenance (O&M) cost per unit
- Fuel cost per unit

The steps followed in estimating each of the aforementioned components are given below:

Fixed cost per unit

For estimating the fixed cost per unit, the following elements have been considered:

i. **Capital cost & life of plant –** The capital cost per MW and the life of the plant has been considered. These have been estimated on the basis of Central Electricity Regulatory Commission (CERC) (Terms and Conditions of Tariff) Regulations, 2009 (CERC, 2009) and CERC benchmarking of Capital Cost for Thermal Power Plants (CERC, 2012).

ii. **Plant Load Factor (PLF) and auxiliary consumption -** The CERC (Terms and Conditions of Tariff) Regulations, 2009 (CERC, 2009) provide operating norms for all the thermal power stations operating in the country. Thus, in the present analysis, a normative PLF of 82% for coal based and 72% for gas based power plants has been assumed. Further, normative auxiliary consumption of 9.50% in case of coal-based generation and 3% in case of gas-based generation has been assumed. These parameters have been used to estimate the gross generation and net generation (energy sent out) of the power plants.

iii. **Determination of levelized capital cost -** In order to estimate the levelized capital cost, the present value of the capital cost was annualized based on the life of plant and a suitable discount rate.

iv. **Determination of the discount rate -** The discount rate has been arrived at based on the Weighted Average Cost of Capital (WACC). For arriving at the WACC, the debt equity ratio has been assumed to be 70:30. The current prime lending rate (PLR) i.e. 14.75% is assumed to be the rate of interest for debt. Return on equity is assumed to be 16%, as per the CERC norms.

v. **Capital Recovery Factor (CRF) -** Power generation projects typically involve substantial up-front capital commitments. Thus, for computing fixed cost of a project over its whole life there is a need to provide for a discount factor that would convert this one-time investment into costs distributed equally over the life of the project. For this purpose CRF is computed. It is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time. CRF is used to compute the per-unit annuitized capital cost of power generation.

O&M cost per unit

Operation and maintenance (O&M) cost has been considered as a fixed percentage of capital cost based on the norms provided under the CERC (Terms and Conditions of Tariff) Regulations, 2009 (CERC, 2009). These have further been escalated at the rate of 7.14% per annum and subsequently levelized over the life of the plant. The escalation factor has been determined based on the average of the Wholesale Price Index (WPI) for last three years.

The assumptions regarding fixed and operating costs are also summarised in Table 3 below.

Table 3: Normative assumptions for power generation

Element	Unit	Domestic Coal based plant	Imported Coal based plant	Domestic Gas	LNG
Heat rate	kcal/ kWh	2500	2500	2000	2000
Capital cost*	Rs. million/ MW	44	44	33	33
PLF	%	82%	82%	72%	72%
Auxiliary consumption	%	9.50%	9.50%	3%	3%
Life of plant	Years	25	25	25	25
Fixed operating cost as % of capital cost	%	3.49%	3.49%	4.65%	4.65%
Specific Consumption	ml/ kWh	1	1	1	1
Discount Rate	%	15.13	15.13	15.13	15.13

Source: CERC (2009); * CERC (2012)

Exchange Rate

For the purpose of estimation of financial costs of all fuel options including imported coal and LNG, US$ exchange rate is assumed to be Rs 52.2/ US$ which is the average of the exchange rate over the period January to June, 2012.

Fuel prices

Landed prices for various fuels have been arrived at after taking into consideration transportation charges, taxes and other intermediate costs incurred. Tables 4 to 7 summarize the price build-ups used for various fuels. All these figures have been arrived at based on the information as available in August 2012.

Fuel cost per unit

This has been estimated by taking into consideration the cost of primary and secondary fuels required for power generation.

Landed prices of the primary fuels have been calculated to arrive at the fuel cost per unit. Data for the secondary fuel has been taken from available published sources.

Table 4: Domestic Coal Price Build-up

Particulars	Units	
Pit head price	Rs/ tonne	725.00
Royalty	Rs/ tonne	98.75
Stowing Excise Duty (SED)	Rs/ tonne	10.00
Surface transportation charges	Rs/ tonne	44.00
Sizing charges	Rs/ tonne	39.00
Sub-total (A)	Rs/ tonne	916.75
Sales tax	%	4.00
Sales tax (B)	Rs/ tonne	37.00
Clean Energy Cess (C)	Rs/ tonne	50.00
Total Price (A+B+C)	Rs/ tonne	1003.42

Source: CIL (2012), CCO (2012)
Pit head prices are as applicable from January, 2012 and all other duties are for 2011-12

Table 5: Imported Coal Price Build-up

Particulars	Units	
GCV	Kcal/ kg	6322
FOB price	US$/ tonne	111.53
Ocean Freight and insurance (Indonesia to India)	US$/ tonne	10.47
CIF price	US$/ tonne	122.00
Exchange Rate	Rs/ US$	52.21
CIF price	Rs/ tonne	6370.38
Import duty	%	5
Import duty	Rs/ tonne	318.52
Landed Cost (A)	Rs/ tonne	6688.90

Particulars	Units	
Sales Tax	%	4
Sales Tax (B)	Rs/ tonne	267.56
Total Landed Cost (A+B)	Rs/ tonne	6956.46

Source: Coalspot.com, CCO (2012)
Imported coal prices are the average for 2011-12 and taxes and duties are as applicable in 2011-12

Table 6: Price build-up of Domestic Gas

Particulars	Units	
Price inclusive of Royalty	Rs/ mBtu	219.3
Transmission Charges	Rs/ mBtu	15-60.94
Price of gas before taxation	Rs/ mBtu	234.31-280.25
Sales Tax	%	12.50
Delivered Price of gas	Rs/ mBtu	263.6-315.28

The price (inclusive of royalty) used here is the current price for APM gas and the PSC price of the gas produced in KG D6

Table 7: Price build-up of LNG

Particulars	Units	
LNG landed Price	US$/ mBtu	9.00
Regasification charge	US$/ mBtu	0.67
Marketing margin	US$/ mBtu	0.17
Landed price + marketing margin	Rs/ mBtu	513.83
Transmission charge (see Table 8)	Rs/ mBtu	0-27.7
Price of Gas before taxation	Rs/ mBtu	513.83-541.53
Sales Tax	%	12.50
Delivered price of Natural Gas	Rs/ mBtu	578.05-609.22

LNG landed price is the long term contract price as of July 2012 and other charges are for 2011-12
Note: All these price build-ups have been prepared by TERI based on discussions with sector experts.

Assumptions for transportation charges

An important component that impacts the cost of power generation is the freight charge incurred in transporting the fuels within the country.

In case of coal, railway freight charges have been taken, which is distance specific in nature. The distances between the power plants and sources of fuel have been calculated on the basis of the fuel linkages as shown in Tables 1 and 2. The railway freight rates have been obtained from the Freight Rates published by the Ministry of Railways.

For natural gas, the transmission tariff is assumed to be the rate levied on the Hazira Vijaipur Jagdishpur (HVJ) pipeline and East West Pipeline (EWPL) on a zonal basis as discussed earlier. It may be noted that the HVJ and EWPL zonal tariff has also been used for linkages for pipelines that are either under construction or not existing at the moment so as to compute the transportation charges. The zone wise transportation charge for gas along the HVJ and EWPL pipeline are given in Table 8.

Table 8: Existing tariff rates for the EWPL and HVJ pipelines (in Rs/ mBtu)

Zone	EWPL	HVJ
Zone 1	15.00	19.83
Zone 2	42.00	22.48
Zone 3	53.69	25.10
Zone 4	58.75	27.70
Zone 5	60.94	------

Source: Petroleum and Natural Gas Regulatory Board (2010)

Note: Each zone covers a distance of 300 km

Total financial cost per unit

The total cost of generation is arrived at by summing up per unit capital, O&M and fuel costs.

Prices and calorific values

The price of domestic coal consumed in India varies according to the grade of coal, with each grade having a different calorific value. There has been a change in the coal categories that have increased to 17 from the 7 categories that existed earlier under the GCV based system. The coal grades E and F are generally used in India for the purpose of power generation. As per the current system, grades 9, 10, 11 and 12 have been considered. The average GCV for the coal grades under consideration is 4300 kcal/ kg.

On the other hand, the calorific value of imported coal is much higher compared to domestic coal. In India, coal is imported from Indonesia, Australia and South Africa, with more than 70% of coal being imported from Indonesia. Thus, in the base case scenario, calorific value of imported coal is assumed to be the same as that considered for Indonesian coal price reference i.e. 6322 kcal/ kg. Average Free on Board (fob) price of coal imported from

Indonesia for the period July 2011 to June 2012 was US$ 112/ tonne and the same has been assumed in the base case.[4]

In case of natural gas (domestic and LNG), calorific value is considered to be 10,000 kcal/ tscm. The computed weighted average price of domestic gas from various sources is US$ 4.26/ mBtu. Hence, in the base case, price of domestic gas is assumed to be US$ 4.2/ mBtu (Rs. 7405/ tscm). This is the prevailing price of gas produced in APM blocks and has also been approved by the government for the RIL for its gas find in KG Basin. These two producing sources together account for the largest share of natural gas produced in the country.

The price of LNG in the Base Case is assumed to be US$ 9 mBtu[5] (fob price), which is the long-term contract price of Qatar's Rasgas. Tables 9 to 12 indicate the fuel prices considered for the analysis.

Table 9: Calorific Values and Fuel prices

Fuel	Calorific Value		Price	
	Unit	Value	Unit	Value
		Coal		
Pithead	Kcal/ Kg	4300	Rs/ tonne	953.42*
Domestic Non Pithead	Kcal/ Kg	4300	Rs/ tonne	1956.82**
Imported	Kcal/ Kg	6322	Rs/ tonne	8170.76
		Natural Gas		
Domestic	Kcal/ tscm	10000^	Rs/ tscm	11027.2#
LNG	Kcal/ tscm	10000^	Rs/ tscm	24175#

*Price for Korba
** Price for Bharuch
^ Gail (http:/ / www.gailonline.com/ customerzone/ power.htm)
#Price for Delhi

[4] http:/ / www.coalspot.com/ indonesian-coal-price-reference/ ?c=1&selBrandBenchmark=5&selMonth1=0&selYear1=0&selMonth2=0&selYear2=0, accessed on July 26, 2012
[5] Based on discussions with experts. Rate applicable in August 2012

Table 10: Price and Calorific Value of Domestic Coal

Location	**Calorific Value**		**Price**	
	Unit	Value	Unit	Value
Delhi	Kcal/ Kg	4300	Rs/ tonne	2273.62
Korba (Bilaspur)	Kcal/ Kg	4300	Rs/ tonne	953.42
Bharuch (Vadodara)	Kcal/ Kg	4300	Rs/ tonne	1956.82
Vishakapatnam	Kcal/ Kg	4300	Rs/ tonne	1476.52
Allappuzha (Kochi)	Kcal/ Kg	4300	Rs/ tonne	3006.02
Talcher (Orissa, Angul)	Kcal/ Kg	4300	Rs/ tonne	953.42
Dhanbad	Kcal/ Kg	4300	Rs/ tonne	1184.32
Agartala	Kcal/ Kg	4300	Rs/ tonne	2824.82
Kaparkheda (Maharashtra)	Kcal/ Kg	4300	Rs/ tonne	1503.42

Table 11: Price and Calorific Value of Imported Coal

Location	**Calorific Value**		**Price**	
	Unit	**Value**	**Unit**	**Value**
Delhi	Kcal/ Kg	6322	Rs/ tonne	8170.76
Korba (Bilaspur)	Kcal/ Kg	6322	Rs/ tonne	7959.86
Bharuch (Vadodara)	Kcal/ Kg	6322	Rs/ tonne	7479.56
Vishakapatnam	Kcal/ Kg	6322	Rs/ tonne	6956.46
Allappuzha (Kochi)	Kcal/ Kg	6322	Rs/ tonne	7346.16
Talcher (Orissa, Angul)	Kcal/ Kg	6322	Rs/ tonne	7106.66
Dhanbad	Kcal/ Kg	6322	Rs/ tonne	7320.96
Agartala	Kcal/ Kg	6322	Rs/ tonne	8827.86
Kapadkheda (Maharashtra)	Kcal/ Kg	6322	Rs/ tonne	7907.46

As can be seen, GCV of coal is an integral part of the computation of fuel cost. Higher the GCV, lower is the specific consumption of coal, lower is the total coal requirement and thus lower is the total fuel cost.

Table 12: Price of Domestic Gas and LNG (Rs./ tscm)

Location	Domestic Gas	LNG
Delhi	11027.22	24175.29
Korba (Bilaspur)	12187.49	24059.22
Bharuch (Vadodara)	10675.89	23823.95
Vishakapatnam	10460.26	22938.68
Allappuzha (Kochi)	12511.15	22938.68
Talcher (Orissa, Angul)	12187.49	23942.25
Dhanbad	12413.39	24175.29
Agartala	12511.15	24175.29
Kaparkheda (Maharashtra)	10911.15	23826.33

Key Findings

Table 13 and Figure 5 summarize the base case for financial cost of power generation based on the various fuel options considered in this study.

Table 13: Financial cost of power generation in the selected locations

Plant Locations	Fuel Options (Rs/kWh)			
	Domestic Coal	Imported Coal	Domestic Gas	LNG
Delhi	3.38	5.47	3.67	6.38
Bilaspur*	2.52	5.35	3.91	6.36
Vadodara	3.18	5.16	3.60	6.31
Vishakapatnam	2.86	4.93	3.55	6.12
Kochi	3.85	5.10	3.97	6.12
Talcher*	2.52	4.98	3.91	6.33
Dhanbad	2.68	5.09	3.95	6.38
Agartala	3.73	5.75	3.97	6.38
Nagpur	2.88	5.35	3.63	6.28

*Pithead Power Stations

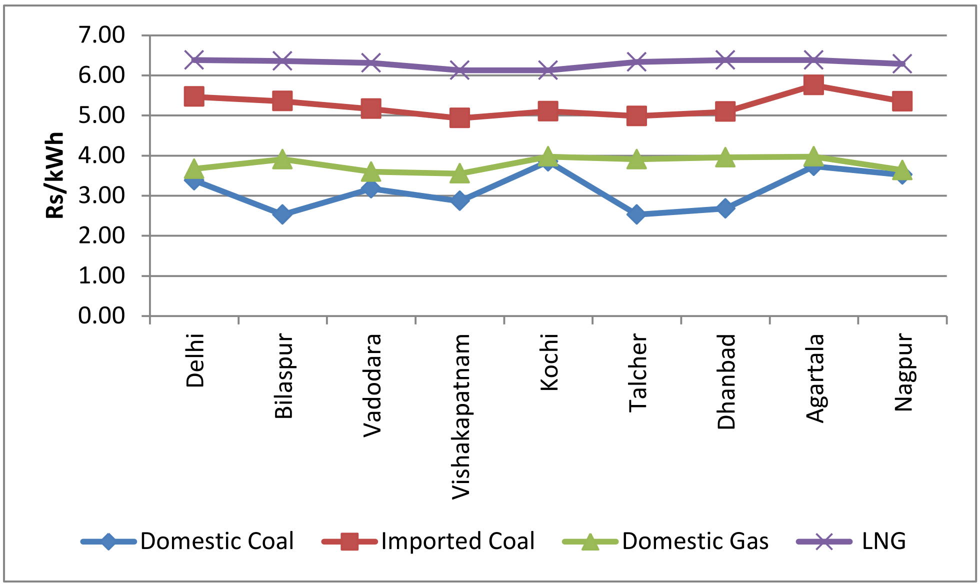


Figure 5: Financial costs of power generation

Increasing the PLF for Gas Based Power Plants

For calculating the cost of power, the average PLF for gas based power plants has been kept at a conservative level of 72%. If however, this level is increased to 90%, the cost of power from gas based plants reduces substantially. In fact, domestic gas becomes competitive with coal at non-pithead locations (Delhi, Vadodara, Kochi, Agartala).

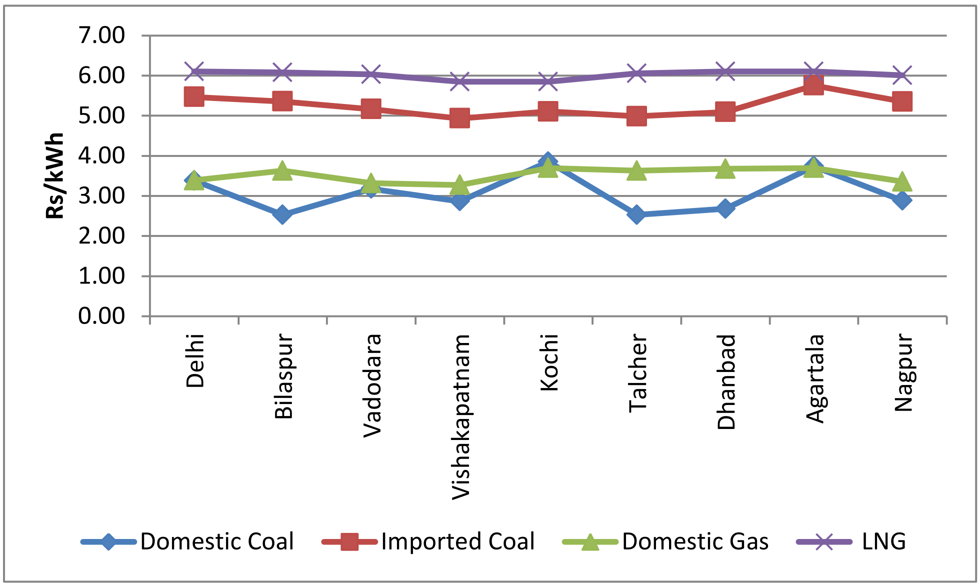


Figure 6: Financial costs of power generation (at a PLF of 90%)

Summary

- Domestic coal based generation at pit head power plants is less expensive than non-pit head coal based generation. This is primarily because of the transportation cost involved in transferring coal to non-pit head locations.
- Imported coal, though having a higher calorific value, is not as competitive as domestic coal due to its higher costs.
- Domestic gas based power generation is more expensive that domestic coal based generation at all locations. However, at locations that are far from coalfields, the difference between the cost of domestic coal and domestic gas based power generation reduces substantially. This can be observed for Delhi, Vadodara, Kochi and Agartala. Further, as the PLF for gas based plants are increased, the cost of domestic gas based power becomes competitive with coal based power.
- LNG is the most expensive fuel for power generation. This is primarily due to the high costs of fuel and the prevailing exchange rate.

Carbon emissions in power generation

Introduction

India's per capita emissions of CO_2 are currently 1.18 tCO_2, a level that is much lower than the emissions of the developed world and this trend is expected to continue. However, the country's vulnerability to change in climate is estimated to be very high thereby warranting actions and concentrated efforts to reduce the country's emissions.

In 2007, the Prime Minister made a declaration at the G8+5 Summit in Heiligendamm, Germany that the per capita emissions of India would never exceed those of the developed countries. Following this, in 2008, the National Action Plan on Climate Change (NAPCC) was also brought out. The Action Plan constitutes eight missions that address sector specific recommendations to meet the challenges of climate change.

While no legally binding commitments have been made, or are required to be made at international forums, in 2009 prior to the COP15 at Copenhagen, India voluntarily committed to reduce its emissions intensity of GDP by 20-25 per cent from 2005 levels by 2020. Although these statements are voluntary in nature, they do represent the inclination of policy makers towards addressing the rising concerns of climate change. The importance of synergizing efforts towards reducing GHG emissions across sectors has also been recognized in the Approach Paper to the Twelfth Five Year Plan (Planning Commission, 2011b). An Expert Group on Low Carbon Strategies for Inclusive Growth has been constituted to recommend paths to address the concern of climate change while ensuring inclusive growth. As per the Interim Report of the Expert Group, power generation in India is largely based on coal and this trend is expected to continue (Planning Commission, 2011c).

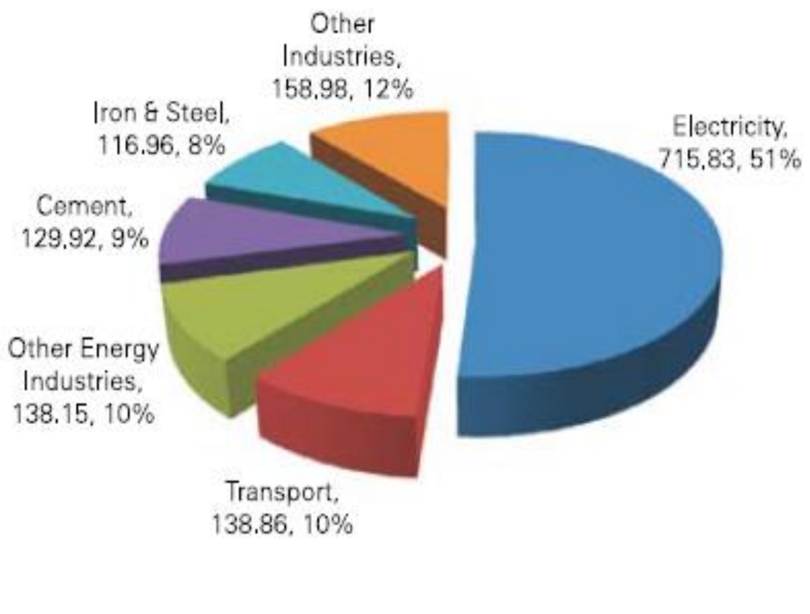


Figure 7: CO_2 emission distribution (tCO_2e) across sectors in 2007

Source: Planning Commission (2011c)

As can be seen from Figure 7, emissions from power are the largest source of GHG emissions and currently contribute more than half the total emissions of the country. The current prices of power in the country do not represent the true cost of externality imposed in terms of the harmful effects of carbon emissions in the process of electricity generation. The present chapter aims to capture the carbon emission cost of power generation with different fuels. It is felt that this will help a more informed policy and decision making about the strategies to be followed for the power sector; this will also be essential in increasing the investment in low emission intensive technologies by power generation companies. While a carbon price of Rs. 50 per tonne of coal mined was imposed in India in 2011, this is neither sufficient, nor truly reflective of the emissions generated in the process of coal based power generation.

In order to adequately account for the emissions generated in the process of electricity production, the cost of carbon needs to be accounted for.

In public economic theory one of the tools used to internalize externalities (environmental and others) is the imposition of Pigouvian taxes. The tax is intended to increase the private cost of a product by an amount equal to the cost of the externality generated in order to arrive at its true social cost. Calculation of Pigouvian taxes therefore necessitates monetization of externality costs.

In the context of power generation, the costs of carbon emitted in the process of mining and combustion of fuels have been internalized in this report. The following sections explain the methodology for calculating the emissions generated and discuss the implications of monetizing these and including them in the financial cost of power generation.

Mining of natural resources imposes significant ecological costs. In addition to the financial costs that are traditionally considered while estimating costs of power generation, there are environmental and social impacts at each point in the fuel cycle. Box 1 summarises these for coal mining.

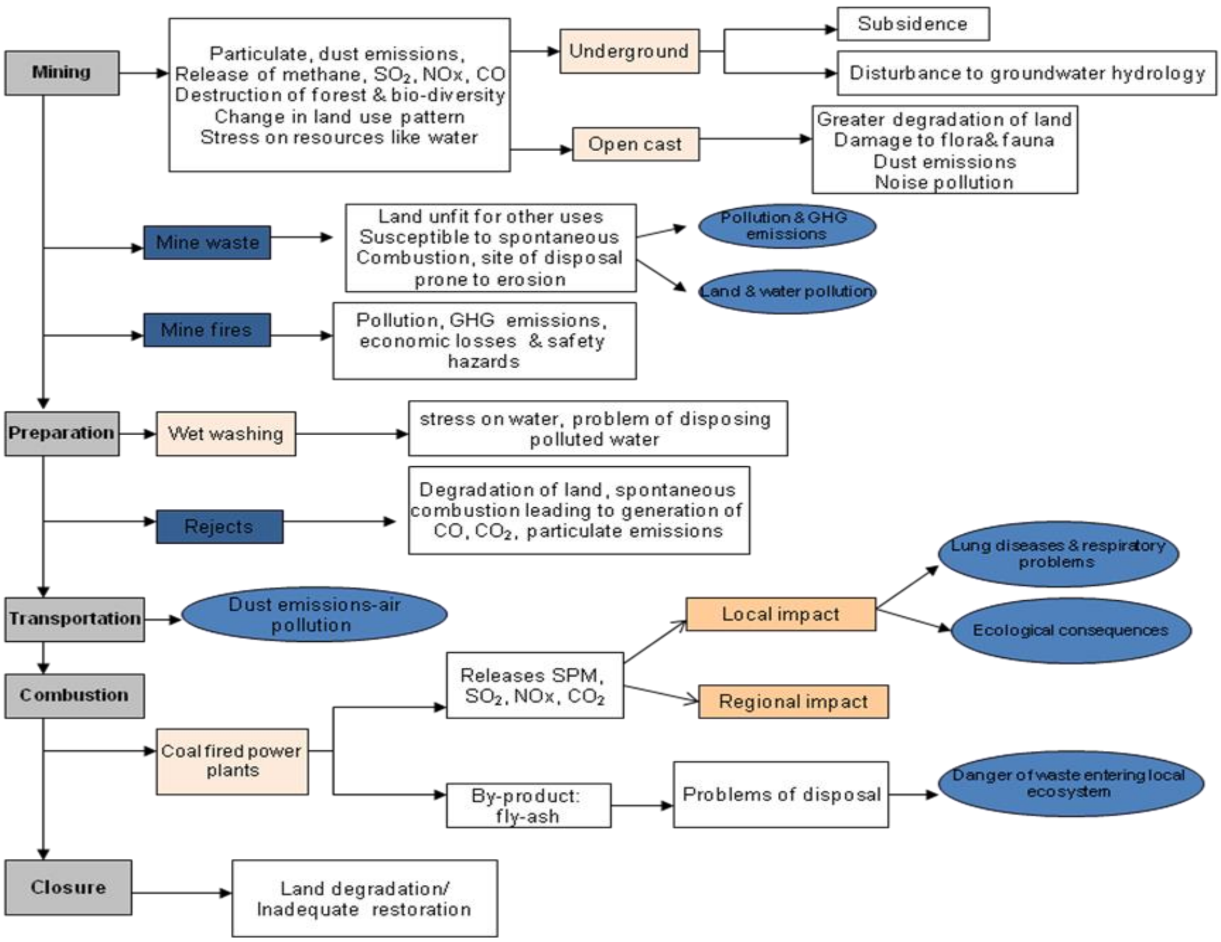
Box 1: Environmental implications of coal mining

The stages of fuel cycle involve mining, preparation, transportation, combustion and closure/ disposal.

At the **mining/extraction stage**, emissions of particulate matter and dust, release of methane in the mines, damage to ecosystems, degradation of land and water table and loss of forests and ecosystems are the major impacts. This is followed by the preparation stage where pollution

During **transportation**, costs of wear and tear of transport infrastructure and emissions during transport of coal from mines to power plants are incurred. And finally, during burning of coal for power generation (i.e. **combustion**), release of toxic material and particulates such as NOx and SO_2 has significant health implications. In addition to this, impact on the communities due to displacement of population, costs of relocation and rehabilitation and the increase in morbidity and mortality of those engaged in various processes can also be considered. Figure B.1 summarises the environmental costs at each of these stages.

Figure B1 – Environmental Cost of each Stage



Source: This analysis has been done as part of a forthcoming TERI study on Energy Sector Risks. The authors acknowledge Arpita Khanna for providing this mapping.

As noted, there are several other environmental and social costs involved in various stages of mining and power generation processes. These are, however, not included while calculating the final costs in this report. Case studies where calculations of such kind have been made for particular regions made are available but to the best of our knowledge these costs have not been quantified for the entire country and throughout the fuel cycle. Separate studies are needed to quantify each of the components and this analysis has not been incorporated in this report.

Emissions during coal mining and extraction

During the process of coal mining, large quantities of methane (CH_4), a greenhouse gas are emitted in the form of fugitive emissions. The quantity of gas released depends on the depth of the mine and the type of coal extracted. In India, coal is extracted largely from open cast/ surface mines and therefore emissions factor of surface mines have been considered. Once the coal has been extracted from the mines, the post mining process (i.e. coal handling after extraction from the ground) also leads to certain emissions. The formula used in this report for estimating the emissions per unit of power generated is as follows:

Emissions (tCH_4) = Emission factor (m^3CH_4/ t) x Coal production (tonnes) x Conversion factor (Gg/ 10^6m^3)

Where

Emission factor (m^3CH_4/ t) = Surface mining emissions + Post mining emissions

CH_4 emissions are calculated based on the per tonne emissions factor which reflects the methane emitted in the process of mining and post mining activities carried out in the extraction of coal.

Further, CH_4 emissions have been converted to CO_2 equivalents using the formula:

CO_2 equivalent emissions = CH_4 emissions from mining x Global warming potential

The global warming potential is the amount of CO_2 emission that would cause the same time-integrated radiative forcing, over a given time horizon, as an emitted amount of a long-lived GHG or a mixture of GHGs, in this case, methane. The equivalent CO_2 emission is obtained by multiplying the emission of a GHG by its global warming potential for the given time horizon.

The methane emission factors (during and post mining) and the global warming potential are both based on the assumptions laid out in the Second National Communication to the United Nations Framework Convention on Climate Change (UNFCCC) (MoEF, 2012). Table 14 summarizes the assumption related to coal emissions and coal based power generation.

Table 14: Calculation of CO_2 emissions from coal mining

Steps	Element	Unit	Value
A	Methane Emission Factor during mining[a]	m^3/ t	1.18
B	Methane Emission Factor post mining[a]	m^3/ t	0.15
C	Total Methane Emission Factor from Mining (A+ B)	m^3/ t	1.33
D	Coal production	T	1
E	Conversion factor	0.67 Gg/ $10^6 m^3$	0.00000067
F	Emissions for 1 tonne of coal extracted (C*D*E)	Gg CH_4	0.0000008911
G	Emissions for 1 tonne of coal extracted (F*1000)	t CH_4	0.0008911
H	Specific coal consumption	kg/ kWh	0.58
I	CH_4 Emissions from one unit of electricity produced	t CH_4/ kWh	0.0000005180
J	Global Warming potential[a]	CO_2 equivalent	21
K	CO_2 equivalent emissions from one unit of electricity produced	t CO_2/ kWh	0.0000290

Sources: [a] MoEF (2012)

Emissions during gas production

As in the case of coal mining, the process of gas production also leads to emissions during the process of flaring of gas. Table 15 presents the steps used in calculating the emissions during natural gas flaring. The figures on flaring of gas pertain to 2010-11 and have been obtained from the Handbook of Statistics on Petroleum and Natural Gas. The assumptions related to heat rate, calorific value and specific consumption are based on the normative assumptions laid out in the Chapter on Financial Cost Estimation. The emission factor is based on the Guidelines issued by IPCC in 2006 (IPCC, 2006).

Table 15: CO_2 emissions from natural gas extraction

Steps	Element	Unit	Value
A	Gross Production in India[a]	Million Cubic Metre	52222
B	Flaring of Natural Gas[a]	Million Cubic Metre	968
C	Heat rate	kcal/ kWh	2000
D	Calorific Value	kcal/ scm	10000
E	Specific Gas Consumption (net)	scm/ kWh	0.2

Steps	Element	Unit	Value
F	Specific Gas Consumption (gross)	scm/ kWh	0.202
G	Flaring of Natural Gas	scm/ kWh	0.002
H	1 Cubic Meter of gas	Btu	35300
I	Flaring of Natural Gas	Btu/ kWh	71.31
J	Flaring of Natural Gas	mBtu/ kWh	0.00007131
K	1mBtu	Tj	0.0010551
L	Flaring of Natural Gas	Tj/ kWh	0.00000008
M	Emission Factor [b]	tC/ Tj	15.3
N	Conversion Factor	44/ 12	3.67
O	Carbon Oxidisation Factor	1	1.00
P	Total CO_2 Emissions	tCO_2/ kWh	0.000004221

Source: [a]MoPNG (2012)

[b] IPCC (2006)

Emissions from combustion of coal and natural gas

Combustion of coal and natural gas during the process of power generation leads to significant emissions of GHGs. To estimate the emissions from combustion, the India specific emissions factor based on the estimates in the Second National Communication to the UNFCCC has been used in case of domestic coal and the IPCC guidelines have been followed for the other three fuels (IPCC, 2006). Table 16 summarises the methodology and estimates.

CO_2 emissions in tonne per unit of electricity produced = Heat Rate of the plant (kcal x kWh) x Conversion factor (TJ/ kcal) x Emission factor (tC/ TJ) x 44/ 12 x Carbon oxidization factor

Table 16: CO_2 emissions during combustion of coal and natural gas

Step	Element	Unit	Domestic Coal based plant	Imported Coal based plant	Natural Gas	LNG
A	Heat Rate	kcal/ kwh	2500	2500	2000	2000
B	Conversion	TJ/ Kcal	0.00000000419	0.00000000419	0.00000000419	0.00000000419
C	A*B	Tj/ kwh	0.0000105	0.0000105	0.0000084	0.0000084
D	Emission Factor	tC/ TJ	26.13	25.8	15.3	15.3
E	Conversion Factor	44/ 12	3.67	3.67	3.67	3.67
F	Carbon Oxidisation Factor	1	1.00	1.00	1.00	1.00
G	CO_2 Emissions	tCO_2/ Kwh	0.001003	0.000990	0.000470	0.000470

As discussed previously, the heat rates assumed here are based on the CERC norms of 2009. Summarising the findings from Tables 14-16, the total emissions from coal and gas based production is presented in Table 17.

Table 17: Summary of emissions from various fuel options

Element	Unit	Domestic Coal based plant	Imported Coal based plant	Natural Gas	LNG
Emissions due to Mining/ Extraction	tCO_2/ Kwh	0.0000290	NA	0.000004	NA
Emissions due to Combustion of Fuels	tCO_2/ Kwh	0.001003	0.000990	0.000470	0.000470
Total Emissions	**tCO_2/Kwh**	**0.001032**	**0.000990**	**0.000474**	**0.000470**

Source: TERI estimates

The CO_2 **emissions from combustion of coal are almost twice the emissions from combustion of natural gas. Further, the total emissions accruing due to mining of imported coal and LNG are not included here as these emissions originate in the countries that export the respective fuels.**

Economic Cost Analysis

Having compared the relative carbon emissions generated from power generation using alternative fuels for power generation – i.e. domestic and imported coal and domestic gas and LNG in Chapter 3, this chapter attempts to monetise the carbon costs of power generation in order to examine the economic cost of power generation.

It is pertinent to mention here that *Economic Cost* in this Report refers to the sum of financial costs and the carbon costs of power generation calculated in Chapters 2 and 3. There are other definitional components of economic costs notably the opportunity costs, other externalities etc that are not considered here.

The first step in calculating the economic cost of power generation is to determine an appropriate price of carbon to monetize the emissions in order for these to be internalized in the generation cost.

Carbon prices

Using an appropriate price of carbon is central to estimating the carbon costs of power generation. Different studies have attempted to value the price of carbon based on varying economic and financial principles.

One of the major mechanisms for market traded instruments is the existing Emissions Trading Scheme (ETS). Under the European Union's (EU) ETS, traded instruments include Carbon Emission Reductions (CERs), European Union Allowances (EUAs) and emission reduction units (ERUs).

The current market prices of these instruments however, are not a reliable indication of the long-term outlook of the markets. These prices are affected by other factors such as prevailing overall economic conditions, market sentiment, investment in low carbon technologies by the market players and expectations of the future carbon trading landscape etc. and therefore cannot be used when calculating the environmental cost of power production. Particularly in the second phase of trading, the economic downturn resulted in a relative over-supply of permits which has, in turn, led to a decline in the prices of trading instruments in the European carbon markets. Further, the modification relating to inclusion of the aviation sector in the scheme and the subsequent ban on US airlines by the US government to comply with this requirement also led to a relative oversupply in the market (Haita, 2013). In fact, the EU is currently evaluating measures for structurally reforming the trading mechanism in order to address this issue of growing surplus allowances in the market.

Therefore, basing a carbon price solely on the existing markets in EU may not fully reflect the long-term externalities. It is for this reason that different reports and regions have suggested different carbon prices.

In 2007, the Stern Review also provided a basis to monetize the cost of carbon (Stern, 2007). It proposed a 'Social Cost of Carbon' (SCC) which is the cost of impacts associated with an additional unit of greenhouse gas emissions. In the Review, different levels of social costs were calculated based on the projected trajectory of carbon emissions in the future. In the BaU scenario, the social cost of carbon rises to as much as US\$85/ tCO_2e and along a trajectory to maintain the emissions rate at 550 ppm CO_2e, the price of carbon would be US\$ 30/ tCO_2e and finally, along a trajectory to maintain the level at 450 ppm tCO_2e, the price will fall further to US$ 25/ tCO_2e. Stabilisation at 450 ppm CO_2e implies an 85%reduction from BaU in 2050[6] and at 550 ppm CO_2e will imply a reduction of 60-65%.[7]

In 2010, the Report of the United Nations Secretary-General's High-level Advisory Group on Climate Change Financing proposed a carbon price of between US$ 20 and 25/ tonne of CO_2e up to 2020. The United States Interagency Working Group on Social Cost of Carbon (2010)[8] also proposed a carbon price of US$ 25/ tonne. This International Energy Agency (IEA), in its report on Projected Costs of Electricity Generation (IEA, 2010) used a carbon price of US$30/ tonne for the OECD markets. Recently, Australia has also imposed a carbon tax of AU$ 23/ tCO_2e which will rise to AU$ 25/ tCO_2e by 2015. This will be followed by the introduction of an ETS in the country wherein carbon prices will be determined by the forces of demand and supply. And ultimately, the Australian markets will be linked to the EU ETS with the intention of establishing an intercontinental exchange.

To assess the implications of changes in global carbon markets, alternate scenarios are considered with carbon prices of US$30, US$ 85 and US$ 10[9] per tonne are considered. Tables 18-20 and Figures 8-10 summarise these findings.

Table 18: Total cost of power generation (financial + carbon) at a carbon price of US$ 30/ tCO_2 (in Rs./ kWh)

Plant Locations	Fuel Options			
	Domestic Coal	**Imported Coal**	**Domestic Gas**	**LNG**
Delhi	4.97	7.02	4.41	7.11
Bilaspur	4.11	6.91	4.65	7.09
Vadodara	4.76	6.72	4.34	7.04
Vishakapatnam	4.45	6.48	4.29	6.86
Kochi	5.44	6.65	4.72	6.86
Talcher	4.11	6.53	4.65	7.07
Dhanbad	4.26	6.64	4.70	7.11
Agartala	5.32	7.30	4.72	7.11
Nagpur	4.47	6.90	4.38	7.02

[6] Stern (2007), pg 233
[7] All prices are at 2000 levels
[8] Referred in IMF (2013)
[9] This is close to the average traded price of CERs in the past one year.

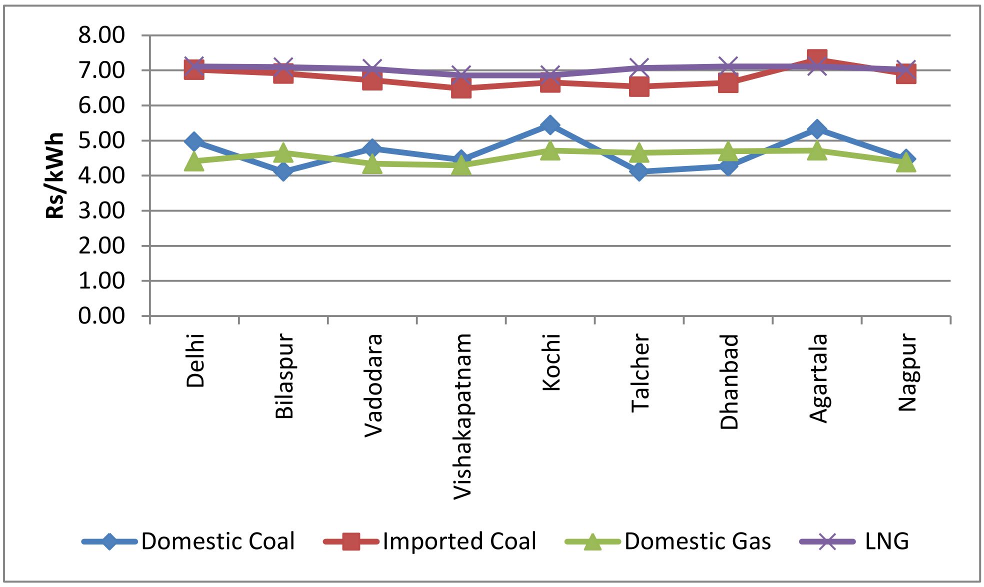


Figure 8: Total cost of power generation when carbon prices are US$ 30/ tCO_2e

As can be seen, at a carbon price of US$ 30/ tCO_2, **domestic gas becomes comparable and even cheaper at various locations and the difference between cost of power generated using LNG and imported coal reduces.** At locations like Delhi, Vadodara, Vishakhapatnam, Kochi that are relatively close to domestic gas sources, transport costs of gas are lower than those for coal. Further, in Agartala which is far from gas and coal sources, the cost of gas based generation is competitive to coal based power generation.

Table 19: Total cost of power generation (financial + carbon) at a carbon price of US$ 85/ tCO_2 (in Rs./ kWh)

Plant Locations	Fuel Options			
	Domestic Coal	**Imported Coal**	**Domestic Gas**	**LNG**
Delhi	7.88	9.86	5.77	8.46
Bilaspur	7.02	9.75	6.01	8.44
Vadodara	7.68	9.56	5.70	8.39
Vishakapatnam	7.36	9.33	5.65	8.21
Kochi	8.35	9.50	6.08	8.21
Talcher	7.02	9.38	6.01	8.42
Dhanbad	7.18	9.49	6.06	8.46
Agartala	8.23	10.15	6.08	8.46
Nagpur	7.38	9.74	5.74	8.37

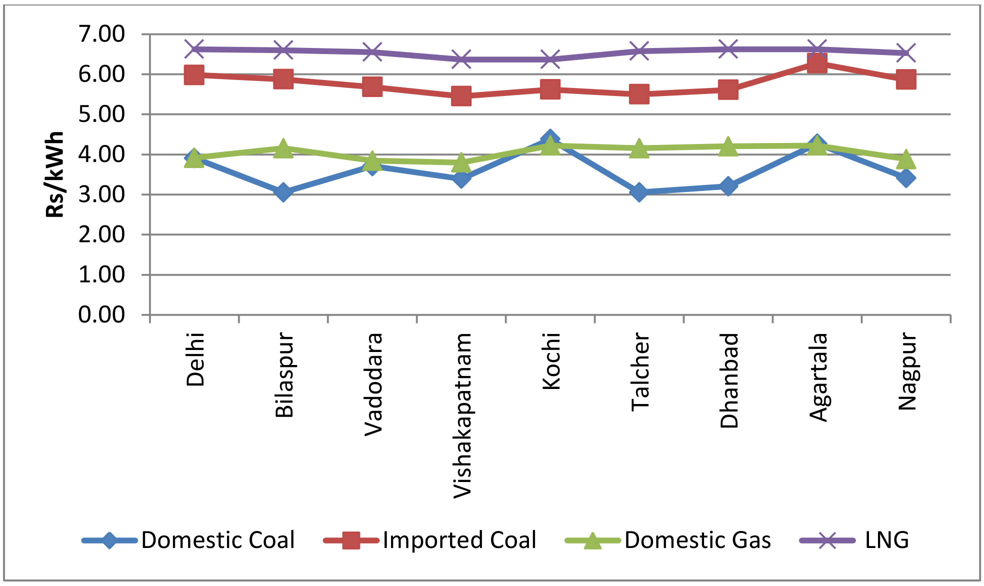


Figure 9: Total cost of power generation when carbon prices are US$ 85/ tCO_2e

At a carbon price of US$ 85/tCO_2, domestic gas and LNG based power generation are less expensive than domestic coal and imported coal respectively. In fact in Kochi, which is close to an LNG terminal and Agartala which is at a considerable distance from the coal fields, LNG is comparable to imported coal as well.

Table 20: Total cost of power generation (financial + carbon) at a carbon price of US$ 10/ tCO_2 (in Rs./ kWh)

Plant Locations	Fuel Options			
	Domestic Coal	**Imported Coal**	**Domestic Gas**	**LNG**
Delhi	3.91	5.98	3.92	6.62
Bilaspur	3.05	5.87	4.15	6.60
Vadodara	3.71	5.68	3.84	6.55
Vishakapatnam	3.39	5.45	3.80	6.37
Kochi	4.38	5.62	4.22	6.37
Talcher	3.05	5.50	4.15	6.58
Dhanbad	3.21	5.61	4.20	6.62
Agartala	4.26	6.27	4.22	6.62
Nagpur	3.41	5.87	3.88	6.53

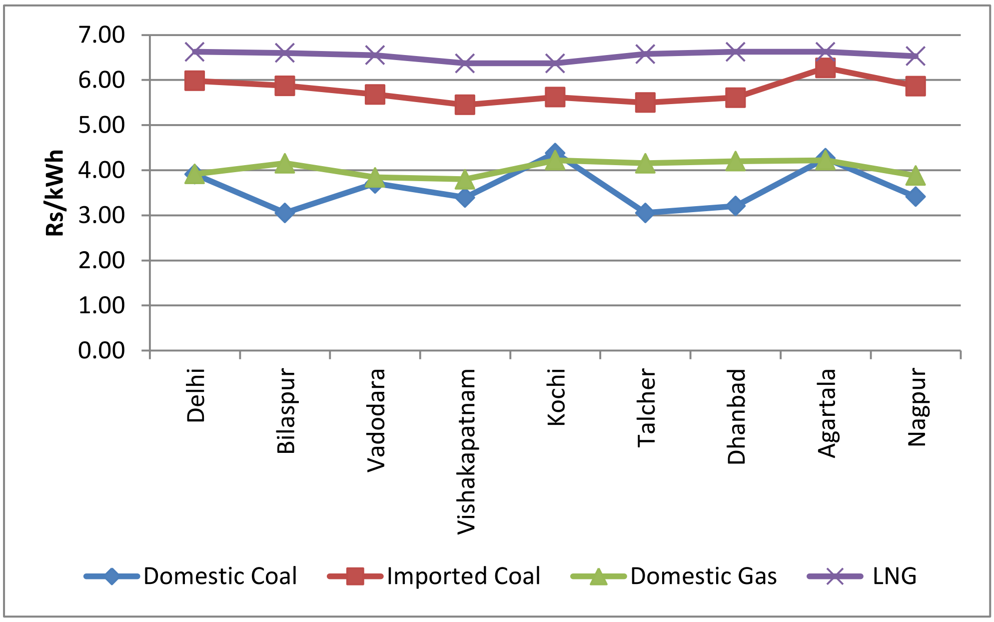


Figure 10: Total cost of power generation when carbon prices are US$ 10/ tCO_2e

At a carbon price of US$ 10/ tCO_2, gas loses its competitiveness except in the locations that are either closer to gas sources or at locations that are situated far off.

This underlines the preeminent need to accurately account for carbon prices to adequately capture impact of carbon emissions while estimating the relative costs of power generation.

Increasing the PLF for Gas Based Power Plants

Figure 11 below presents an alternative scenario when the prices of carbon are at US$30/ tonne and the PLF for gas based plants is increased to 90%.

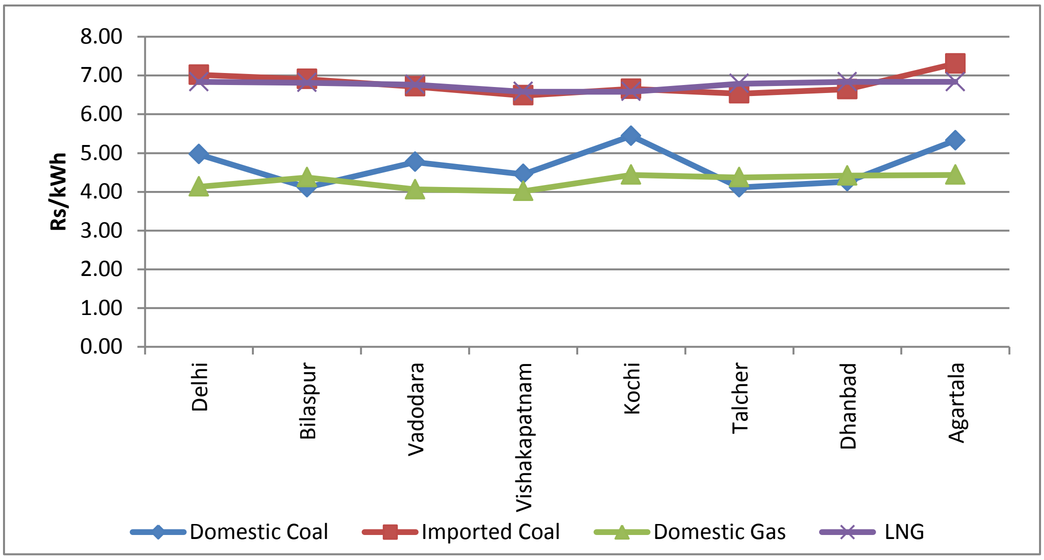


Figure 11: Total cost of power generation when carbon prices are US$ 30/ tCO_2e and the PLF for gas based power plants is 90%

As can be noted, the relative economics of the four fuels gets altered dramatically as LNG becomes competitive with imported coal at most locations and domestic gas becomes less expensive than domestic coal at most locations.

The major conclusion from the preceding analysis outlines the need for right pricing and valuation of environmental implications of power generation in order to truly account for difference in environmental damage caused by coal based power vis-a-vis gas based power generation. Even though the total carbon generated in mining and combustion of coal is twice that of natural gas, the total monetary impact is not reflected sufficiently in final power generation costs. Further, a higher PLF for gas based power plants can significantly alter the relative economic competitiveness of the fuels as gas becomes extremely competitive with coal at sufficiently high PLF rates.

Implications of the change in the coal and natural gas policy landscape

As can be seen from the Tables and Figures in the preceding chapter, even after accounting for the carbon cost, domestic coal remains the cheapest option at or near the coal pit head, while domestic gas at US$ 4.2/ mBtu becomes the cheaper alternative in other locations for power generation. As regards the choice between imported gas (LNG) and imported coal, the former is the costlier option in all locations, though the cost advantage of imported coal over LNG comes down significantly after we include the carbon cost of generation.

Two important factors, however, need to be taken into account while we formulate our future policy options about possible fuel mix for power generation. These are:

1. Coal availability, domestic and imported
2. The national/ international natural gas scenario

Domestic Coal Availability

Extractable coal reserves in India are not adequate (Batra & Chand, 2011) and this has led to an increase in dependence on imports of coal. However, changing pricing and taxation policies in exporting countries will affect the availability of imports as well.

Coal which accounts for over 54% of the country's total electricity generation, is dominated by the government-run company Coal India Limited (CIL). CIL, which meets more than 80% of India's coal requirements, has been facing slow growth in output as its expansion plans have been affected by delays in environmental clearances and problems in land acquisition.

It has been estimated that there will be a shortage of approximately 265 MMT (35.5 MMT coking coal and 230 MMT non-coking coal) of coal as per the Report of the Working Group on Coal Twelfth Five year plan in the BaU scenario. Moreover, the imposition of "no-go" area restriction by the Ministry of Environment and Forests (MoEF) has forced the halting of mining in over 203 coal mines that have a capacity to produce 600 MMT of coal. As per the Ministry of Coal, this ban could affect power generation to the tune of 1,30,000 MW (Ghoshal, 2011). The recent cancellation of captive coal blocks will also constrain the development of planned power generation capacity in the absence of fuel availability.

Further, changes in pricing mechanism of domestic coal will also impact the viability of using coal for power generation. Domestic coal was characterized on the basis of useful heat value (UHV) for steam coal in India till 2011. In 2012, the pricing of non-coking coal was changed to a fully variable Gross Calorific Value (GCV) system. The grading system has been redefined, raising the number of grades from 7 to 17.

The switch to GCV sets a much higher standard for calculating the energy content of coal as it will take into account the content of highly combustible elements like carbon, hydrogen, oxygen, nitrogen and sulphur. This will change coal pricing as higher grades will fetch better prices. Indian coal has high ash content and most of it falls between Grades E and G. At present, the average price of coal is 30 to 60 per cent lower than the international price and the shift to the globally accepted GCV could affect the cost of coal based power generation (Chakravartty, 2012).

Further, the budget announcement of 2010-11 led to the creation of the National Clean Energy Fund (NCEF). Under this, a levy of Rs. 50/ tonne is being imposed on coal, lignite and peat produced in the country. Although a relatively small amount, this levy has also increased the cost of domestic coal.

Implications of Changes in Regulations in Coal Exporting Countries

However, the changes in pricing and export regulations in the coal exporting countries have created an uncertainty regarding imported coal availability. There have been significant changes in the international coal scenario in terms of changes in pricing policy, taxes etc. in Indonesia and Australia which are the major exporters of coal to India. As a result of this, coal imports have been affected. Further, with the new restrictions and increased cost of coal import from Indonesia or Australia, as also port and other infrastructural constraints, increasing the level of imports to meet the demand supply gap in India may be extremely difficult. Some of the major changes in international markets are summarised below.

- **Introduction of carbon taxes -** The Government of Australia has introduced a carbon tax of AU$ 23/ tCO_2 and is planning to introduce an Emissions Trading Scheme (ETS) beginning 2015. This will adversely affect the price of imported coal. Further, in case of domestic power producers that have entered into power purchase agreements (PPAs), rise in coal prices will affect the cost of generation.

  The **new Indonesian policy that stipulates benchmarking of coal prices to international market indices** is likely to increase the cost of coal imports for Indian firms. An Indonesian Coal Reference Price (HBA) is the basis of the Indonesian coal pricing and the introduction of HBA is changing the cost dynamics for foreign investors and international purchases as the reference price is now linked to global prices. The prices are now based on four internationally acceptable coal indices[10] that are used to generate a monthly Indonesian coal reference price for about 62 types of coal including 8 types of benchmark qualities (Coalspot.com, 2011). This is expected to increase the cost of imported coal for power plants in India including the Ultra Mega Power Plants (UMPPs) by at least US$ 30 per tonne.

- **Possibility of further changes in regulations in Indonesia -** The Indonesian government is in the process of drafting regulations that could ban the export of low-grade coal by 2014. This is likely to apply to coal below 5100 kilocalories (kcal) in value. Further, the Indonesian government is also planning to impose a 25% tax on exported coal that will further escalate the price of imported coal for India.

This situation has increased the level of uncertainty for the existing and upcoming coal based power plants especially the UMPPs. At present, most of PPAs under competitive bidding are based on the fixed cost of production, which may not remain viable after the sudden change in Indonesian coal prices. Power projects with a total capacity of 43,000 MW honored under the power purchase agreements are currently under construction and of this about 13,000 MW or 30% of the capacity is based on the imported coal. These power producers have offered bids based on their agreements with fuel suppliers predominantly in

[10] The reference price is to be used by coal producers for all future spot and term contracts. This coal benchmark price is based on the index average of ICI-1 (Indonesia Coal Index), Platts-1, Newcastle Export Index, and Global Coal Index.

Indonesia. This will impact the final price of power generated and thereby affect the profitability of power producers.

Domestic natural gas production

Natural gas production from the eastern offshore KG D6 block, is projected to fall to 24 million standard cubic metres per day (mscmd) in the 2013-14 fiscal year compared with 28 mscmd in the current financial year and is forecasted to fall further to 20 mscmd in 2014-15 (Platts, 2012). This has reduced the availability of natural gas for power plants that are now running at low PLF rates. The actual supply of gas to power plants up to January 2013 was 41.45 mscmd as against their requirement of nearly 86 mscmd. Power generation capacity that was created keeping in mind the availability of gas from the KG basin stands unutilised. The National Thermal Power Corporation has also slowed down the expansion of its gas based generation plants.

Another factor constraining the development of domestic gas sources is the domestic gas allocation and pricing policies. The prices of gas discovered under the New Exploration and Licensing Policy (NELP) and pre-NELP contracts are fixed on the basis of Production Sharing Contracts (PSCs) signed between the operators and the government. The current domestic prices are much lower compared to the prices of LNG imported at both long term contract rates as well as spot LNG. It is unlikely that a price of US$ 4.2/mBtu can be maintained because of the pressure for an international price as is allowed for crude oil under NELP contracts. However, an increase in prices of natural gas will also affect the viability of downstream gas consuming sectors such as power generation where the final consumer prices are also controlled.

Allocation of gas is determined on the basis of the Gas Utilization Policy of the Government which mandates allocation of gas to priority sectors to ensure that their demand is met before allowing sales to other sectors. Shortages of domestic gas have implied that demand of even the priority sectors such as power is also being met only partially.

International Gas Scenario

The potential availability of natural gas worldwide is, by present reckoning, better than that of crude oil. The Reserves to Production ratio of crude oil in 2011 was 54.2 years while for natural gas it was 63.6 years (BP, 2012). The production of shale gas in USA and Canada has further changed the scenario in favour of natural gas. As a result of surge in production of shale gas, the prices in North America have fallen drastically and are currently around US$ 3 - 4/mBtu, while for the Asian markets, the price is nearly three times this rate. The rise in Asian prices was essentially driven by a spike in demand from Japan, the largest consumer of imported LNG as a result of the tsunami that cause the nuclear based power plants in the country to shut down. The Asian prices are now stabilising to under US$13/mBtu. These may further get affected if the excess gas from North America is exported to Asian markets. If that happens, there will be an impact on the LNG prices in Asian markets as well. Imports of gas to North America from Middle East are declining (Figure 12) and are likely to stop soon because of domestic availability of natural gas and shale gas in USA and Canada.

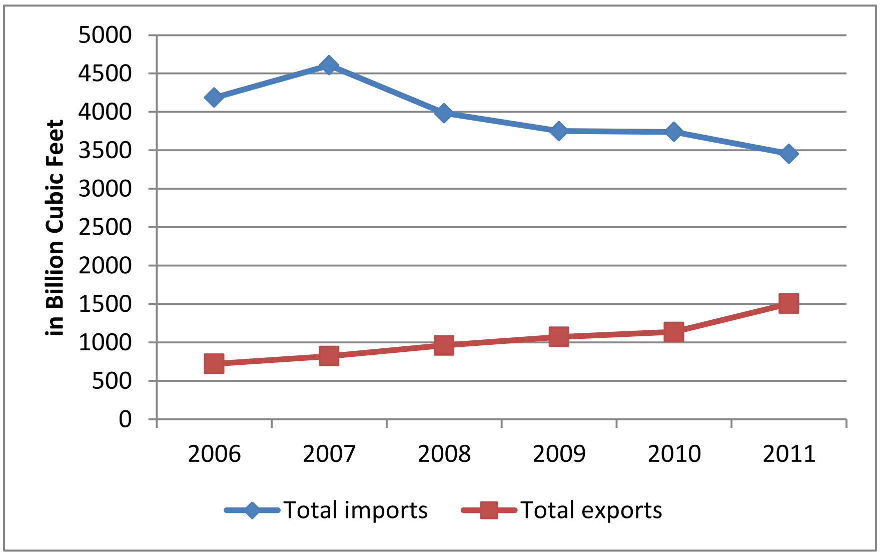


Figure 12: Imports and exports of natural gas in USA

Source: Energy Information Administration (2012)

On the other hand, both USA and Canada are planning to set up more liquefaction facilities with an obvious intent of exporting. The combination of stoppage of Middle East gas export to North America and possible export from America will put a definite downward pressure on international prices of gas.

The Shale Gas revolution can affect Asian markets in the following ways – first the excess gas from the Middle East that was earlier exported to North America will now be available for Asian and European markets and secondly, exports of gas from North America will affect the availability of gas in the world markets and finally, countries in Asia, primarily China and India are also exploring their own sedimentary basins for prospects of finding shale gas domestically. If and when this production begins, there is a possibility of meeting a larger share of domestic demand from domestic supply itself. However, the issues of water and land requirement for shale gas exploration will be critical in determining its future course in India.

Summary and Recommendations

This chapter summarises the findings of the report and recommends a way forward.

Summary of findings

Findings with respect to rising power generation demand and the availability of fuel to meet the demand:

- Demand for power will continue to rise and significant capacity additions are needed to meet the growing demand supply gap.
- Fuel requirements will also rise in tandem with the growing electricity generation, thereby imposing significant pressure on domestic coal resources to meet the demand. The recent issue of shortage in domestic coal availability and the imposition of coal linkages on CIL add to the concerns about supply of coal for power generation.
- Changing policies in coal exporting countries will also affect the viability of using imported coal. Further, the technical limits to blending of coal in existing power generation plants determine the extent to which imported coal is used for power generation in the country.
- There is a need to consider and accelerate gas based power generation in the country. Here too, it will be important to consider LNG as an option for power generation since production of domestic gas is not rising to meet the increasing demand.
- In the international gas markets, the production of shale gas and the changing dynamics in international gas markets may reduce the prices of Asian LNG contracts as well.

Following are the key findings with respect to the competitiveness of each fuel option taking into account financial and carbon emission costs

- Using the traditional methodology of computing costs of power generation, coal remains the least expensive option for power generation. However, as costs of carbon are internalized, domestic natural gas emerges as a better and more competitive option especially in distant locations.
- Even if we consider only the CO_2 emissions from mining and combustion of fuels, emissions from coal-based generation are twice that from natural gas based generation. In addition to the CO_2 costs, there are significant other environmental and opportunity costs of coal mining which when accounted for will add to the costs of coal-based power generation.
- At higher carbon prices, using LNG for power generation becomes more competitive and at a carbon price of US$ 85/ tCO_2e, LNG based power production is less expensive than imported coal based generation in all sites and even becomes comparable to domestic coal based generation in power plants located close to LNG terminals. The relative viability, however, changes if we assume the carbon price at US$ 30/ tCO_2e.

- Gas based power plants have shorter gestation periods and lower fixed and capital costs and can provide a feasible solution if gas prices are affordable in the medium term.

Taking into account all the findings discussed in this report, gas based power generation needs to be stepped up. Without this, it may be difficult to meet the growing demand for power in the country as also the targets for the Twelfth Five Year Plan.

Recommendations and way forward

This report has analysed, elaborated and collated some phenomena which are fairly well-known. These are:

- Domestic coal production will continue to substantially fall short of the domestic demand. This shortfall, by all indications, will increase further over time.
- Domestic gas production is unlikely to increase significantly over the present level, unless some discovery of new big fields takes place in the near future. While shale gas could be looked at as an option, the high requirement of water and the possibility of water table contamination will significantly affect the development of this resource in India.
- The reliance on imported coal for power generation has continued to increase, but new restrictions and policies in the main coal exporting countries like Australia and Indonesia will seriously limit the coal import capacity of the country. Further, the increase of coal consumption in Europe which was witnessed in the recent months is likely to impact the global coal markets, at least in the medium term. This will affect the overall trajectory of coal prices.

On the other hand, GDP growth of 8% to 10% envisaged by our planners, or the aim of the Government to provide electricity to even the remotest corners of the country, will be impossible to achieve unless adequate electricity, whatever be the fuel it is based on, is made available.

It follows that increased import of natural gas, whether in the form of piped gas or liquefied natural gas, will be an unavoidable necessity in the years to come. While proposals for piped natural gas are being pursued, and must continue to be pursued, nothing has matured as yet and our success will depend on, among other things, our management of the geo-political conditions.

Increased impact of LNG, we feel, is therefore an imperative necessity in the interest of equity, growth and improved management of the climate change problems. There is no doubt that LNG may be financially a more costly option. However, when we factor the carbon emission cost, the arguments in favour of LNG improve. As has been brought out in Table 18, the difference between the power generation costs based on imported coal and those based on imported LNG at a carbon price of US$ 30/ tCO_2 are far from substantial. The differences will come down further with the impact of the export of shale gas from beyond North America on the international prices of natural gas.

Relative prices of imported coal and LNG will keep on changing. What is, however, important is the logic of unavoidable dependence on LNG in view of the constraints related to availability of domestic coal and natural gas. The Ministry of Power has indicated (Press Information Bureau, 2012) that there had been a generation loss of 9 billion units (BU) and 11 BU due to shortage of coal and gas respectively in 2011-12. We have to plan for adequate availability of power which is so essential for economic growth and general well-being of the people.

No amount of increased availability from nuclear power (because of problems of fuel availability), power based on renewable energy (at the technology of the moment or of the foreseeable future) or hydel power (because of geological and resettlement concerns) can make up for a major shortfall in thermal power based on coal and natural gas. The installed capacity of the power sector based on all fuels stands at approximately 200,000 MW as on 31st March 2012. Nuclear power capacity addition targeted in the Twelfth Five Year Plan is 2,800 MW as against the current capacity of 4,780 MW. Current renewable capacity stands at 22,000 MW and the planned capacity addition in the Twelfth Five Year Plan stands at 18,500 MW. Further, hydel capacity stands at 39,000 MW as against the planned capacity addition of 9,200 MW. The total planned capacity addition during the Twelfth Plan is about 94,300 MW. It is clear that the bulk of this capacity addition will have to be thermal i.e. coal or gas based. With constraints on domestic availability of coal and natural gas and difficulties in the import of coal, as has been outlined in this report, there does not appear to be any escape from larger reliance on LNG than that in the current scenario.

Some of the key areas of recommendation are as follows. While many of these have been recognised by the various committees and expert groups, they continue to be the major factors affecting the country's energy trajectory.

Infrastructure requirements for coal – Increasing the rail and port capacities to efficiently evacuate domestically mined coal and to facilitate imports of coal in the country is essential. In case of domestic coal, the washery capacity also needs to be increased. While this has been included in the plans over the past few years, actual addition to capacity has been limited.

Improving the technology for coal mining – Increasing the share of underground mining and underground coal gasification will facilitate access to coal at greater depths

Infrastructure for natural gas – As the dependence on imports of natural gas is expected to rise, so too is the requirement for import facilities in the form of LNG terminals, FSRUs etc. further, domestic pipeline capacity also needs to be enhanced. While licenses to construct have been awarded to many operators, the pace has been slow and in fact, some of the pipeline licences have even been cancelled by the Petroleum and Natural Gas regulatory Board.

Provision of **adequate incentives and regulatory transparency** will be the key determinant of timely addition to the country's energy infrastructure. In addition to this, transparent and remunerative pricing policies will go a long way in determining the extent to which domestic production is enhanced. In particular, **rationalisation of power sector tariffs** is the prime driver behind the choices of fuel. A mechanism whereby competitive pricing can be ensured will determine the course of the country's long term energy policy.

A comprehensive plan must be drawn up without any delay for increased import of LNG. Such a plan will have to include, at the international level, intensive **negotiations with present and potential LNG exporting countries** and, at the national level, substantial augmentation of the infrastructure like shipping, regasification, storage, pipeline facilities.

To conclude, despite some increased financial cost for import of LNG, we have to plan for substantially increased import of LNG if we have to avoid crippling and a much larger economic cost on account of widespread shortage of power in the country.

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