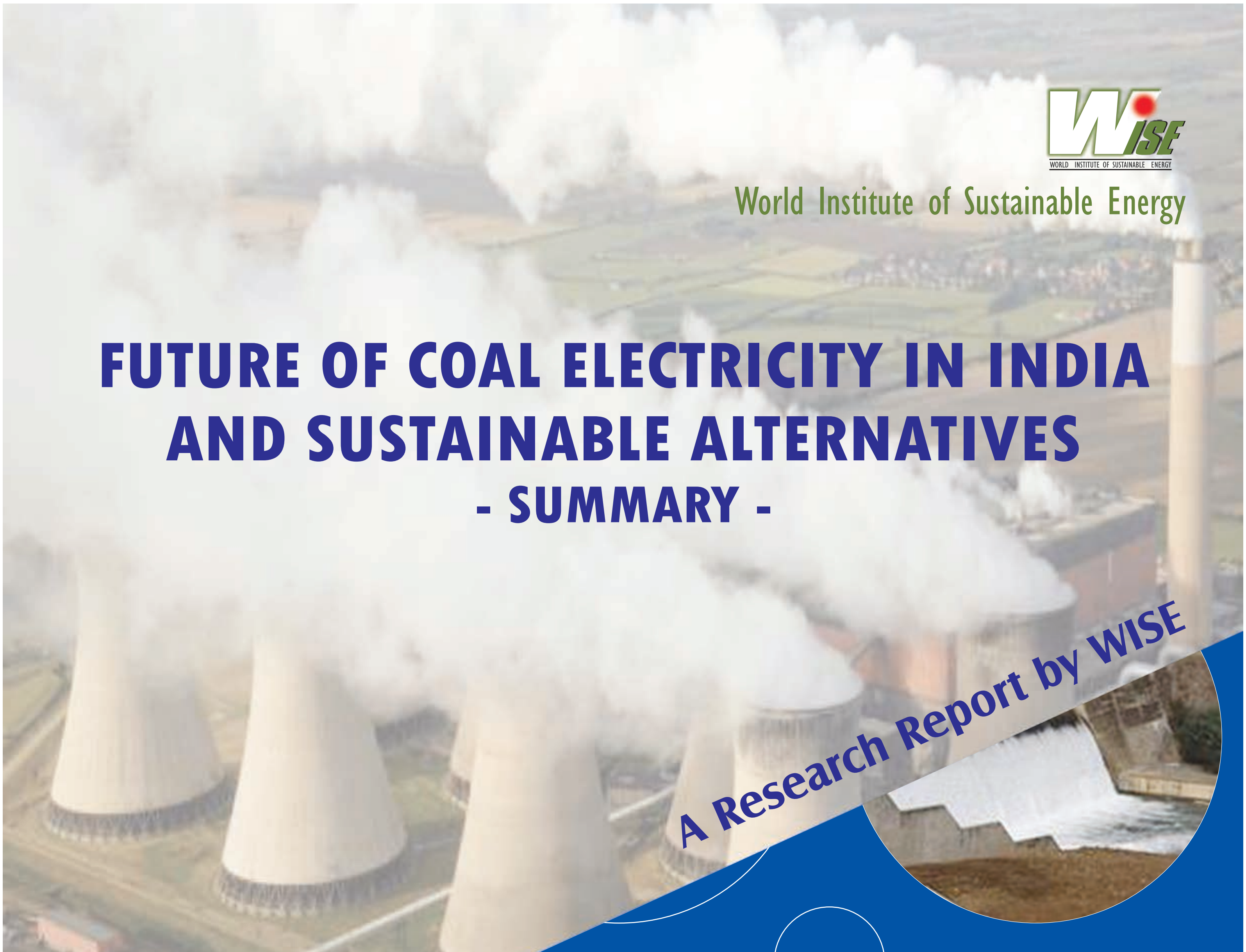

World Institute of Sustainable Energy

FUTURE OF COAL ELECTRICITY IN INDIA AND SUSTAINABLE ALTERNATIVES

- SUMMARY -

A Research Report by WISE

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– Summary –

A RESEARCH REPORT BY WISE

World Institute of Sustainable Energy, Pune

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FOREWORD

Coal is currently the mainstay of the Indian power sector. Understanding the long-term and multifarious implications of a coal-based strategy for power generation is crucial to India's energy security. As a research and knowledge-based institution focusing on core areas of sustainability and energy security, WISE deemed it extremely critical to study the problems, prospects and challenges of coal in India. This study was done over the past twelve months and covers the entire gamut of issues related to coal mining, processing, and combustion for thermal power generation in India from a holistic perspective. It links six themes—coal as a resource, environmental and climate externalities, the economics of coal, macro-economic implications of coal import, alternative RE-based transition pathways, and policy pointers for creating a new framework for India's energy security.

Modern society has been made possible on the bedrock of coal and the electricity produced from it; any alternate ways of producing electricity would still undeniably need electricity derived in large part from coal during the transition period. Since India does not have enough proved resources of conventional natural gas, coal may have to play the role of 'bridge fuel' for grid balancing and facilitating the transition to a green energy economy—till such a time that storage technologies and other advancements such as smart grids are widely available and commercially viable. However, the global threat posed by climate change cannot be addressed by a coal-based pathway. Climate mitigation is a major motivation, besides energy security and energy policy.

We do recognize the principle of 'differentiated responsibility' in solving the climate problem: that developed countries need to first accept prime responsibility. We also recognize that constraints such as macro-economic, geopolitical, environmental, and resource limitations could derail a coal-based power generation strategy if India proceeds on a business-as-usual routine leading to sudden energy shocks. So the study is aimed at steering India's long-term energy policy in the right direction. This report is not about the demonization of coal nor is it intended to "stop coal". We also wish to steer clear of all the recent controversies in the media about coal block allocations in the country. While assessing the reserves of coal in India, we have not relied on the extreme perspectives of "scarcity" and "abundance" of coal.

A team of about fifteen researchers from WISE were involved in this study, besides two notable senior external consultants, Prof Ramprasad Sengupta, a respected senior economist; and Amarendra Sinha, a well-known coal geologist (who spent most of his career in Coal India Ltd). The full report is about 390 pages, covering 14 chapters, with over 400 authentic references. In this summary, we have created a different structure in 9 sections, but have brought out all the essential findings. Sincere efforts have been taken to see that the findings of the study are accurate, to the best extent possible. We hope that this report will be widely read and considered by all stakeholders, especially by policy makers in India, and help shape India's future energy policy. The truisms and certainties of the twentieth century no longer hold true. In the twenty-first century, we face stark energy and economic policy choices, and making the right choices will help us build a resilient and sustainable energy economy.

G M Pillai
Founder Director General, WISE

May 2013,
Pune

ACKNOWLEDGEMENTS

The World Institute of Sustainable Energy (WISE) would like to acknowledge the contribution made by different lead authors and their respective teams from WISE as well as our external consultants, without whom this study would not have been possible. The Research Team was led by G M Pillai, Founder Director General, WISE. Besides providing valuable suggestions and guidance, he also monitored the entire effort from time to time. The coordination of research and report writing was done by Prof Sanjeev Ghotge from WISE. The lead authors and research team included:

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Prof Ramprasad Sengupta was assisted by Kartik Yadav of the India Development Foundation and Naveen J Thomas of the Delhi School of Economics. We take this opportunity to thank them for their efforts. We also wish to place on record our appreciation of the assistance provided to Prof Sengupta by the National Institute of Public Finance and Policy, New Delhi, and the India Development Foundation, Gurgaon.

Thanks are also due to Praveena Sanjay, Joint Director & Head (Communications and Coordination) for her inputs in qualitatively shaping this summary and editing it; Beena Nair, Executive Officer to the Director General for preparing the manuscript; Sachin Holkar and Vinita Phinehas for carrying out the layout and design of the summary report.

TABLES AND FIGURES

Tables

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ABBREVIATIONS

ARKA Additional Resources in Known Areas
BAU Business-as-Usual
BOO Build-Own-Operate
BoP Balance of Payments
Bt Billion Tonnes
BU Billion Units
CAD Current Account Deficit
CAGR Compound Annual Growth Rate
CCS Carbon Capture Sequestration
CEA Central Electricity Authority
CIL Coal India Ltd
CSP Concentrated Solar Thermal Power
CTL Coal-to-Liquid
CUF Capacity Utilization Factor

ERC Electricity Regulatory Commission
EREC European Renewable Energy Council
EPC Engineering, Procurement, Construction
FEV Full Electric Vehicle
FDI Foreign Direct Investment
FPL Florida Power and Light Company
FRBM Fiscal Responsibility and Budget Management
GDP Gross Domestic Product
GW Gigawatt
HREG High RE, High Gas
IEA International Energy Agency
IEP Integrated Energy Policy
IISCO Indian Iron and Steel Company
INCCA Indian Network of Climate Change Assessment
JNNSM Jawaharlal Nehru National Solar Mission
kW Kilowatt
kWh Kilowatt Hour
ktoe Kilo Tonnes Oil Equivalent

LREG Low RE, Low Gas
Mg/l Milligrams per Litre
MoEF Ministry of Environment and Forests
Mt Million Tonnes
Mtoe Million Tonnes Oil Equivalent
Mtpa Million Tonnes per Annum
MU Million Units
MW Megawatt
NAAQS National Ambient Air Quality Standard
NCDEX National Commodity Exchange
NEP National Electricity Plan
NO_x Nitrogen Oxides
NPA Non-Performing Asset
PESA Panchayat [Extension to Scheduled Areas] Act
PFC Power Finance Corporation
PLF Plant Load Factor
PPA Power Purchase Agreement
PPM Parts per Million
RE Renewable Energy
ROE Rate of Interest
R/P Reserves/Production

SCC Specific Coal Consumption
SCCL Singareni Collieries Company Ltd
SO_2 Sulphur Dioxide
SPM Suspended Particulate Matter
TISCO Tata Iron and Steel Company
TOE Tonnes Oil Equivalent
TSP Total Solid Particulates

UCG Underground Coal Gasification
UMPP Ultra Mega Power Project
UNFC United Nations Framework Convention
VOC Volatile Organic Compound

KEY FINDINGS AND RECOMMENDATIONS

The research study titled, *Future of Coal Electricity in India and Sustainable Alternatives*, has attempted to realistically assess the future of coal-based thermal power generation in the country, while at the same time assessing alternatives to ensure India's long-term energy, environmental and economic security. While the findings are startling and have never before been put forth in the country, they are crucial for shaping India's future economic policy, energy policy, and energy security. Policy formulation is after all about envisioning and securing the future and cannot be based on emotional and subjective arguments. Policy makers believe in the famous dictum: "In God we trust; everyone else should show statistics." Hence the study has attempted to derive the facts and figures relevant to India's future energy policy and macro-economic management. The key findings and recommendations are summarized below.

I. FINDINGS

Coal as a Resource

- The total estimated coal reserves in India is 51.09 billion tonnes (Bt). However, the recoverable reserves are only 40.62 billion tonnes. Domestic coal production in India is likely to peak after 2031/32 at 1,100 million tonnes per annum (mtpa). This assessment is based on reserves to production ratio (R/P) and does not consider risks, constraints and other linking factors.
- World coal production is likely to peak around 2030. This is almost the same time that Indian production would also begin to peak.
- India is getting increasingly dependent on imported coal for power generation. In 2011/12, India imported a total of 98.92 million tonnes (Mt) of coal – (68.893 Mt non-coking coal and 30.036 Mt coking coal). This is projected to rise to 192 million tonnes in 2012/13.

Risks of Securitization of External Supplies

- Securitization of external supplies in the long-term is fraught with many dangers (medium level of risk) like increasing prices, decline of exportable surplus of major importers due to country policies aimed at conserving resources for future domestic use, competing importers like China, etc.
- Even if coal is available for import, India's ability to import will be severely constrained by unsustainable levels of current account deficit (CAD).
- Different scenarios of GDP growth and energy imports were considered for the future. It emerges that a business-as-usual (BAU) scenario of fossil fuel imports could result in highly unsustainable levels of CAD, upwards of 13% GDP in 2030/31 and even reaching 39% of GDP by 2030/31 in a worst-case scenario. The sustainable level is considered at around 3% of GDP.
- In the absence of viable alternatives to oil and the need for gas imports to sustain installed capacity, it would not be possible to restrict import of these fossil fuels. However, there are viable alternatives to coal and hence it may become imperative to curtail coal imports to contain CAD in the not-too-distant future.

- The environmental externalities of coal mining, processing, and combustion, and their combined effects on biotic resources, habitats, water availability, livelihoods, and health of people will also work as major limiting factors in the future. Especially, attempts to dilute the restriction of 'no-go' forest areas for mining of coal, will render large tracts in central Indian states barren—devastation for short-term gain when other alternatives are available.
- Water availability for the complete value chain of coal mining, processing, and power generation will be another major constraint in the future. The average water requirement in India for power generation alone is around 3.83 litres/kWh. Some thermal power plants like Parli and Chandrapur in Maharashtra are facing closure due to water shortage.

The Cost of Electricity: Renewables Reaching Grid Parity

- Even from an economic perspective, large-scale development of coal-based generation may not be advisable in the long term. At current prices of coal, the tariff for new coal power from domestic coal will be ₹3.78/kWh (6.87¢/kWh). If 90% imported coal is blended, the tariff will increase to ₹5.86/kWh (10.65¢/kWh). Even pool pricing will significantly increase the cost of coal-based electricity.
- The above prices of coal-based electricity do not consider hidden subsidies and the cost of externalities. An earlier research study by WISE found that coal-based electricity already enjoys a hidden subsidy of 68 paise/kWh (1.45¢/kWh). This does not include subsidies given for transportation of coal. Based on internationally accepted norms of quantifying externalities, the best estimate of externality cost of coal power would be ₹8.92/kWh (17.84¢/kWh). When these two (subsidies + cost of externalities) are added, the real cost of coal-based power in India could range from ₹12.75/kWh (25.94¢/kWh) for domestic coal to ₹14.83/kWh (29.72¢/kWh) for imported coal-based power.
- It would be seen that even today, renewable power is cheaper than coal-based power. Wind power is available in different states in the tariff range of ₹3.51 (7.16¢/kWh) in Tamil Nadu to ₹5.00+ (10.20¢/kWh) in Punjab and Maharashtra. Solar power prices have fallen significantly in the recent past. In the recent bidding process in Tamil Nadu, the lowest quoted rate for solar power was ₹5.95/kWh (12.13¢/kWh).
- Solar power may reach grid parity sooner than expected—even as early as 2015. So all renewables are racing towards grid parity and have very negligible externalities.

Energy Demand

- Considering 8% growth rate, the final energy demand in 2045/46 would be 1,858 million tonnes of oil equivalent (mtoe) with constant real price, and 932 mtoe with real price increase of 3% per annum. The final energy intensity of GDP is projected to decline at the rate of 1.96% per annum over the time horizon 2009/10 to 2045/46, even if we consider the highest GDP growth of 8% per annum and no real energy price change scenario. The rate of decline of energy intensity can be enhanced to 3.74% per annum if the final energy prices in real terms are allowed to rise at the rate of 3% per annum, inducing technical change for energy conservation.

- The gross electricity requirement ranges between 3,767–3,485 BU in 2045, considering a growth rate between 7% and 8% per annum. A scenario of forced RE can deliver upto 2,980 BU of this requirement by 2045.
- By using the econometric approach, it is found that about 56.5% of electricity would be generated from RE sources by 2045, with an additional 13% from hydro i.e. a total of around 70% of clean electricity in the grid can be achieved. In effect, the partial-end use method shows that 75% clean electricity is possible by 2050.

RE Potential and Growth

- Enough RE resources to the tune of 3,941+ GW including 150 GW of hydropower resources are available for greening the Indian economy.
- The total installed capacity of RE could range between 346 GW and 401 GW by 2032 (33% RE), and 1,731 GW by 2050 (75% RE). The demand for electricity in 2050 for a population of 1.6 to 1.8 billion has been considered at a maximum of 5,500 BU.
- In this scenario, the per capita gross electricity generation would be 3,284 kWh per annum in 2045/46 as per the base case scenario of 8% growth and no real energy price change.
- India may need to increase wind turbine manufacturing capacities from the current ~10,000 MW/annum to 20,000 MW/annum.
- The total land requirement under different scenarios would be less than 30,000 km^2, which is less than 1% of the gross land area of the country.

Benefits of a Green Transition

- Even though land requirement for the complete value chain of coal-based generation and RE would be similar, in the case of RE, the land will not be permanently destroyed (as in coal mining) and can be reused after the project life.
- Rooftop and decentralized off-grid applications do not require land. In addition, RE projects will mostly come up in wastelands or arid and semi-arid areas where productivity and population pressures are low. Hence there will be no displacement, resettlement or rehabilitation problems. In addition, agricultural land will not have to be diverted, thereby ensuring food security.
- RE technologies, except concentrated solar thermal power (CSP) are largely water-neutral. In an emerging water-stress situation due to climate change and environmental destruction, this is a huge benefit vis-*à*-vis coal based thermal projects—some of which are facing closure due to non-availability of water for cooling.
- Keeping the ‘no-go’ forest areas for coal mining intact by moving towards RE generation could save large tracts of pristine forests. This is a great environmental benefit and will help maintain water security, land productivity, and overall environmental security, especially in central India.
- Large-scale biotic destruction caused by pollution from coal mining and coal-based power generation could be avoided.
- Emissions reduction will help improve air quality and prevent large-scale morbidity and mortality caused due to severe atmospheric pollution.

- RE maximization as proposed in this study could avoid up to 3.63 trillion tonnes of CO_2 emissions per annum by 2050.
- RE maximization can generate upto 1.6 million jobs by 2020 and 25 million jobs by 2050 without causing environmental destruction. Millions of green and sustainable jobs can be created.
- De-emphasizing coal after 2022 will also save large investments in infrastructure (ports, railways, etc.) and free considerable rail transport for passenger movement.
- Accelerated development of renewables for power generation can have positive macro-economic impacts by solving the serious problem of current account deficit – which is projected to increase from 13% to 39% of GDP by 2031/32, if the BAU scenario of fossil fuel import continues.
- RE projects have very short lead times or gestation periods. Projects (except CSP) can be commissioned within 6 months to one year, due to the modular nature of equipment. Fast scaling-up of capacity is possible. Thermal power projects have long lead times (from 5 to 10 years), leading to cost escalations and delays in scaling-up capacity.

II. RECOMMENDATIONS

- Exhaustion of coal reserves will not be a wise policy since coal may have to be used as a 'bridge' fuel during the transition to a 75% green energy system by 2050, pending maturity and large-scale availability of storage technologies and modern grid systems. Hence a policy of staggered use of coal is recommended. The concomitant policy choice implies a 1.5% per annum mandated growth rate of RE between 2022/2032 and 2% per annum mandated growth rate for the period 2032/2050.
- Similarly, the solar manufacturing capacity will have to be stepped up from 2,000 MW/annum to perhaps 18,000–25,000 MW/annum by 2020, if accelerated targets are to be achieved.
- Considering the above potential after the installation of planned coal-based power generation capacity in the 12th and 13th plan periods (upto 2022), it would be desirable to go for a 'High RE, High Gas' (HREG) scenario for generation of electricity. Coal-based project installation could be significantly reduced in this scenario to 21,675 MW during the 14th plan period (2022/2027) and 13,645 MW during the 15th plan period (2027/2032). This will be a huge reduction from the 51,400 MW capacity planned for the 12th plan period (2012/2017).
- The above strategy, if implemented, will help contain CAD, externalities of coal-based generation, keep the cost of power down, etc.
- To achieve such a transition, we would require the evolution of an alternative future-oriented policy framework for electricity. It would also require realistic assessment of GDP growth and energy demand by considering strategies for reducing energy intensity and decoupling energy growth from economic growth.
- It is recommended to allow real final energy price index to increase at the rate of 3% per annum. Over the long run, this would aid in reduction of energy intensity and energy conservation targets.

- A coherent articulation of the many policy implications arising from this change of path should be ensured so that long-term performance is not compromised.
- A critical element in such a new policy framework would be the creation of a legal framework or law for accelerated development of renewables.
- Stricter electricity regulation measures to enforce RPO would be required to achieve the projected RE capacity additions.
- Providing low-cost finance in adequate quantities would be critical for this transition. Interest subsidies and such other instruments should be instituted for loans to the RE sector. Besides, a separate 'priority sector status' could be given for lending to RE projects.
- Other concomitant actions like grid augmentation, establishment of green transmission corridors (or HVDC networks) and moving towards a smart grid would be essential. Investments should be planned in these areas.
- Committed actions to promote large-scale R&D, innovation, and human resources development in RE technologies would be essential.
- Besides actions taken at the central government level, state governments should also take proactive measures – as some of them are already doing. State-level RE master plans should be prepared based on revised RE resource assessments. Such master plans should form the basis of a planned transition to a green, clean, and secure energy economy.

III. MOVING FORWARD

This study dispels the myth that coal is eternally essential for India's economic development. In fact, it shows that we can transition to a clean energy system without compromising on our economic development. Such a transition does not exclude coal. Since India has very small proved reserves of natural gas (not considering the yet to be explored shale gas with its serious environmental impacts), coal would need to be used as a 'bridge' or 'transition' fuel. That way the impact of emissions would be staggered over a long period of time, while we transition to a truly green energy economy. The study also proves that such a transition would in fact bring in huge economic, environmental, and climate benefits, while ensuring economic, environmental, and energy security.

The business-as-usual approach is ridden with climate, environmental, and macro-economic risks of gigantic proportions. A holistic approach to solving all the above three problems together is essential. Since the spectre of climate change is haunting us—not just at the global level but also at the local level—environmental priorities would need to be thoughtfully integrated into policies and strategies for energy production and consumption. Such a transition seems imperative, considering the scale, complexity, and significance of the changes underway in conventional energy resources around the world, leading to their peaking around 2030 – often referred to as the 2030 spike – and subsequent decline. It would appear that there are risks in the proposed transition pathway; but the risks are worth taking. A new policy pathway is critical for shaping our future energy economy.

* * *

1. COAL AS A RESOURCE FOR POWER GENERATION – HOW MUCH AND FOR HOW LONG –

Coal is one of the most widely distributed energy resources in the world with estimated world proved reserves in 2010 at 860 billion tonnes and with reserves to production ratio of 118. Six major countries (USA, Russia, China, Australia, India, and South Africa) control the majority of coal reserves in the world. It can be visualized as concentrated in "thirds" – one third in North America (mostly US), one third in Eurasia (mostly Russia), and one third in Asia-Pacific (China, Australia, and India). The top 11 coal producing countries in the world produce about 5.9 billion tonnes (Bt) of coal per year, out of a total world production of 7.7 Bt in 2011. While Germany and South Africa have taken the coal-to-liquid (CTL) path for decades, new large-scale entrants include China and Australia. India has yet to start producing liquid fuels from coal, though 4 large coalfields have been allocated. The spread of CTL, which is said to become viable at oil prices above US$ 54 per barrel, can significantly alter R/P ratios in various countries.

GLOBAL COAL MARKET

Table 1.1 and Table 1.2 give the details of the top seven coal exporters and coal importers respectively. Currently, the world's top exporter is Indonesia with 309 Mt and world's top importer is China with 190 Mt.

Table 1.1: Top Coal Exporters (2011)

Sr. No.	Countries	Total (Mt)	Steam (Mt)	Coking (Mt)
1	Indonesia	309	309	0
2	Australia	284	144	140
3	Russia	124	110	14
4	USA	97	34	63
5	Colombia	75	75	0
6	South Africa	72	72	0
7	Kazakhstan	34	33	1
	Total	**995**	**777**	**218**

Coal is traded around the world, shipped over huge distances by sea to reach the market. Over the last twenty years, seaborne trade in steam coal has increased by about 7% on an average and that of coking coal by 1.6% annually. Overall, international trade in coal reached 938 Mt in 2008. While this is a significant amount of coal, it accounts for only about 17% of total coal consumed, as the rest is still used in the country in which it is produced.

Table 1.2: Top Coal Importers (2011)				
Sr. No.	Countries	Total (Mt)	Steam (Mt)	Coking (Mt)
1	China	190	146	38
2	Japan	175	121	54
3	South Korea	129	97	32
4	India	105	86	19
5	Taiwan	66	62	4
6	Germany	41	32	9
7	UK	33	27	6
	Total	**739**	**571**	**162**

GLOBAL PEAKING OF COAL PRODUCTION

Some studies forecast peaking of US coal production by 2030, China's production by 2015/2020 and world production by 2030 (see Figure 1.1). Some studies indicate the inevitable decline of coal in the near future, but this is not a consensus position.

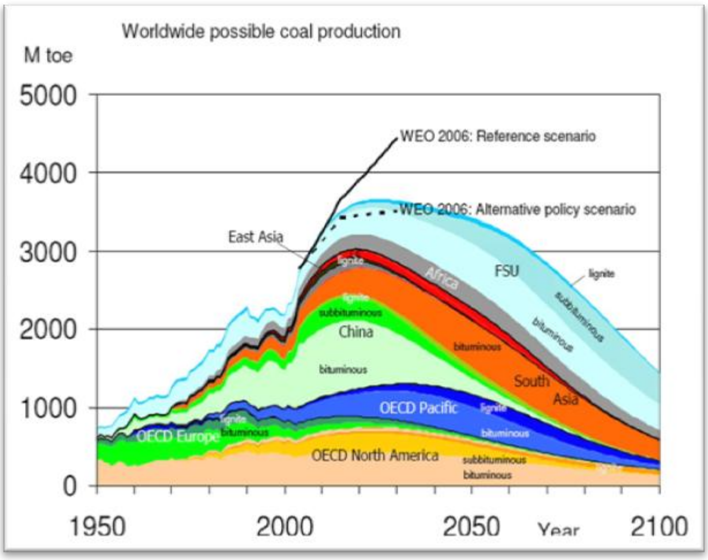

Figure 1.1: Peaking of World Coal Production

RESERVES AND PEAKING OF PRODUCTION IN INDIA

The coal reserves of India have been estimated to be around 51 Bt (see Table 1.3). In the table, United Nations Framework Convention (UNFC)-type means, where the assessment is based on block-block feasibility or mine plans; it is categorized as "studied" where the derivation is based on block-specific resource assessment and application of certainty, constraints, and recovery factors and as "projected" where the different factors are applied to non-block-specific resources. However, our findings indicate that the best current estimate of recoverable reserves of coal in India would be 37.9 Bt.

Table 1.3: Estimates of Coal Reserves in India (Bt)					
Agency	UNFC-type 1	Studied 2	Total Recoverable 3 (1+2)	Projected New Reserves 4	Total Estimated 5 (3+4)
Coal India Ltd (CIL)	18.11	-	18.11	5.40	**23.51**
Singareni Collieries Company Ltd (SCCL) and Godavari valley	3.16	-	3.16	0.40	**3.56**
Captive mines	9.88	9.47	19.35	3.77	**23.12**
Tata Iron and Steel Company (TISCO), Indian Iron and Steel Company (IISCO), etc.	-	-	-	0.90	**0.90**
Total	**31.15**	**9.47**	**40.62**	**10.47**	**51.09**

The projected coal production in India from 2011/12 to 2051/52 is given in Table 1.4 below.

Table 1.4: Projected Coal Production in India [million tonnes per annum (Mtpa)] [Production (50 Mt) planned from Talcher coalfields for captive coal-to-liquid project is excluded]						
Agency	Resource	2011/12	2021/22	2031/32	2041/42	2051/52
CIL	Existing	435	513	467	330	235
	From Additional Resources in Known Areas (ARKA)		1	60	126	126
	From accretions			1	25	26
	Sub-total	**435**	**514**	**528**	**481**	**387**
SCCL and Godavari Valley	Existing	51	56	61	58	55
Captive mines	Existing	38	238	475	475	375
	From ARKA			20	60	74
	From accretions			1	25	26
	Sub-total	**38**	**238**	**496**	**560**	**475**
Old captives (TISCO, etc.)	Existing	15	20	25	17	9
Grand Total		**539**	**828**	**1110**	**1116**	**926**

The above assessment does not include production from any future mining that may be undertaken at depths less than 600 m in areas presently allocated for coal-bed-methane recovery and, as stated above, does not include the 50 Mt production planned from the two captive mines in Talcher coalfields for the coal-to-liquid project. The above projections are based on the assessment of recoverable or extractable coal reserves and show a decline in production after 2031/32.

"The total estimated coal reserves in India is 51.09 billion tonnes. However, the recoverable reserves are only 40.62 billion tonnes. Domestic coal production in India is likely to peak after 2031/32 at 1,100 mtpa. This assessment is based on reserves to production ratio and does not consider risks, constraints and other linking factors."

Average cost of production of coal in India (based on official figures available upto 2008/09) is ₹812.7 per tonne, varying from ₹536 per tonne for opencast mines and ₹3,114 per tonne for underground mines. Future underground mining of coal is increasingly unviable, as experienced all over the world. Official estimates of sectoral demand for coal in 2017 are expected to be: 842 Mt for power generation, 67.5 Mt for sponge iron, 67.2 Mt for steel, and 47.3 Mt for cement, totalling 1,024 Mt per annum. Estimates for other industries including brick-making are difficult to assess but much smaller by comparison.

Domestic coal output for power generation is likely to continuously lag behind demand for coal from the power sector, creating the scenario of increasing coal imports in the years to come. Based on current trends and available information, peaking of domestic coal production is likely to occur around 2031/32 and 2036/37 at 1,110 mtpa. This prediction of peaking is purely based on the R/P ratio, without considering the many constraints and risks. Hence, this peaking of coal production may happen much earlier due to various constraints explained in Sections 4 and 5 of this summary. So it may be safe to start reducing dependence on coal-based power projects after 2022, by resorting to sustainable alternatives.

Any future projection of coal production possibilities has to deal necessarily with uncertainty and resort largely to assumptions. This study bases its assessment on the resources and production possibilities of 705 individual mines and projects of Coal India Ltd (CIL) and 195 captive blocks, constituting almost 56% of the coal resources in the country. The depletion was not factored in since these were already discounted in the assessments of recoverable reserves of the major producers, CIL and Singareni Collieries Company Ltd (SCCL).

The overall future coal production outlined above is premised largely on techno-economic analyses. It is recognized, however, that there are several land acquisition, environmental, and sociological issues that have a bearing on future coal production. More than twenty coal projects are falling in protected forest areas formerly designated as "no go" areas and some of these may not be cleared for mining. Some are parts of corridors of or associated with wildlife sanctuaries. A few projects fall in socially disturbed areas. When domestic production is not able to meet India's increasing demand, the country seeks securitization of supply through imports.

SECURITIZING EXTERNAL SUPPLIES

India's Coal Imports–A Brief History

India has a history of international trade in coal, going back more than a hundred years. The export destinations included the Middle-East, Japan, and Australia, in addition to neighbouring countries in the period before the First World War, rising to 1.14 Mt (more than 6% of production) in 1920. After independence, the exports have been broadly restricted to neighbouring countries, namely Nepal, Bangladesh and Bhutan, being generally less than 2 Mt annually, except in 2010/11, when the figure was 4.4 Mt.

Although 0.2–0.3 Mt of coal was imported annually up to 1930 from UK, Australia, and South Africa, there was practically no further import until 1975/76, when coking coal began to be imported to supplement domestic supply for the iron and steel industry. Non-coking coal began to be imported for the cement industry in the mid 1990s and for power and other industries in the late 1990s (Table 1.5).

Table 1.5: Trends of Coal Import in India (Mt)

Year	Coking coal	Non-coking coal	Total
2001/02	11.11	09.44	**20.55**
2002/03	12.95	10.31	**23.26**
2003/04	12.99	08.69	**21.68**
2004/05	16.94	12.03	**28.97**
2005/06	16.89	21.69	**38.58**
2006/07	17.88	25.20	**43.08**
2007/08	22.03	27.76	**49.79**
2008/09	21.08	27.92	**49.00**
2009/10	24.69	48.56	**75.25**
2010/11	19.48	49.43	**68.91**

Source of Imports

Coal import in 2010/11 (by country) is given in Table 1.6. As of now, Indonesia is the major supplier of coal to India, followed by Australia and South Africa. In the future, there may be more diversification of sources to countries like Mozambique and Botswana.

In the context of India's growing demand for imported coal for the power sector, it is useful to review the potential of coal-producing and coal-exporting countries important from the Indian perspective of location and availability of non-coking coal.

Table 1.6: Coal Imports in 2010/11(Mt), by country			
Country	Coking	Non-coking	Total
Indonesia	0.58	34.36	**34.94**
Australia	15.95		**15.95**
South Africa		10.88	**10.88**
USA	1.48	0.29	**1.77**
New Zealand	0.80		**0.80**
Russia	0.24	0.18	**0.42**
The Philippines		0.26	**0.26**
China	0.11	0.13	**0.24**
Vietnam		0.24	**0.24**
Colombia		0.10	**0.10**
UK, Kenya, Mexico, etc.	0.32	2.99	**3.31**
Total	**19.48**	**49.43**	**68.91**

Source Country Policies and Imported Coal Prices

Almost all countries have, at one time or the other, adopted appropriate policies to control the export price of coal: Australia from 1971 to 1991, South Africa before 1986, and Indonesia in 2011, often guided by the desire to maximize profits from depleting assets and to encourage domestic consumption.

The increase in price impacts the importing countries adversely in many ways, e.g. by raising cost of production, lowering demand (and hence growth), underutilization of infrastructure, etc. If the change is not drastic—like the oil imbroglio of the 1970s—the market generally adjusts to such changes. The index-based pricing of Indonesian coal (introduced recently) affected the market by about US$15–US$20 initially, when the benchmark price for index coal in November 2011 was US$116.65. By May 2012, the benchmark price had come down to US$102.12; it may rise again, but the point is that it will be determined by market forces.

Indonesia had retained the right to direct coal output from private mines for national requirements right from the beginning of the Coal Contract of Work system, but it was never enforced. In 2011, the regulation of domestic market obligation made it mandatory for coal companies to sell up to 35% of the output to specified local entities (basically the state-owned power utility). While for the seller's comfort, the criteria provided have identified only around 50 companies so far, only 24% of the production has been earmarked in the first two years and, in any case, since the coal will be actually sold domestically, for an importer, it reduces the availability and hence increases the cost.

Australia has recently passed two Acts that will affect coal importers adversely. While the more ominous-sounding Mineral Resource Rent Tax may not add substantially to the importer's bill (being meant to target only companies making huge profits), the Carbon Tax of AU$35/tonne is going to increase costs of imports with consequent downstream problems.

"India is getting increasingly dependent on imported coal for power generation. In 2011/12, India imported a total of 98.92 million tonnes of coal – (68.893 Mt non-coking coal and 30.036 Mt coking coal). This is projected to rise to 192 million tonnes in 2012/13. This could go upto more than 600 million tonnes by 2032 if BAU continues."

FUTURE SCENARIO

The study has noted that if India needs to import large quantities of coal, particularly for power generation, there is sufficient potential for locating supplies in the international market for several decades. This, however, entails some medium-level risks. Analysts believe that the hardening of coal prices in the international markets may continue for a few more years until environmental concerns in the northern Asia-Pacific region and the US depress demand and lower prices. The cost of bulk transportation of imported coal may increase due to increase in oil prices in the middle- to long-term, due to peaking of oil. This poses an additional risk factor in the landed cost of imported coal. How far can India afford such large foreign exchange outgoes remains to be seen. In view of the large balance of payments (BoP) problems that such large coal imports may entail, it would be necessary to try and reduce the quantum of imports by:

- enhancing domestic production with special attention on maximizing recovery from reserves in the ground, which is very low at present;
- enhancing efficiency of electricity generation, transmission and consumption to reduce increase in electricity demand;
- expediting the development of alternative and renewable sources of energy.

* * *

2. FUTURE OF COAL IN INDIA'S ELECTRICITY SECTOR

Coal has been the mainstay of the Indian power sector since independence. Key policy and power sector planning documents have continued to promote coal as the main fuel for power generation. Even many of the latest studies that acknowledge climate impacts of coal-based generation point out the need to move away from fossil-fuel-based generation, but yet underscore the importance of coal, based on the arguments of energy security and costs. For policy planners, these are powerful arguments: more powerful perhaps than the arguments for climate-positive actions. However, considering the seriousness of the present coal supply situation and our dependence on high-priced imports, this argument does not seem to be tenable. Consideration of a real positive power policy shift can only happen if we are willing to change the way we define growth and future prosperity, and start looking at energy planning as an interdependent choice that will affect the future of our economy, our ecology, and our very survival.

Clean coal technologies, touted as the climate-friendly face of coal-based power generation, fail to address the core issue of coal dependence. Majority of new coal-based technologies are all process improvement techniques labeled as 'clean coal' and are only marginally more efficient. Carbon capture and storage, on the other hand, is all about high-cost sequestration, which has many long-term uncertainties, including transportation of CO_2 and adequacy of storage sites. Essentially, all the new options focusing on coal support a BAU growth and seem to lack the intent to tackle climate impact issues head on, which is the need of the hour.

COAL PROJECTS IN INDIA

The belief in coal-based generation stemmed mainly from its installed base and contribution in shaping the power sector. Based on Ministry of Power data, Table 2.1 compares the share of cumulative installed coal-based capacity to total installed capacity from 1947 to 2012.

From Table 2.1 and Figure 2.1, it is clear that economic liberalization policies adopted by the Indian government in 1991/92 did not have a major impact on the power sector in terms of actual capacity installed. However, it appears that the Electricity Act, 2003, a landmark legislation that de-licensed electricity generation by allowing the private sector to set up their own generating stations, did have a very far-reaching impact on the sector. Considering the long gestation period of large power projects, it can be seen that the capacity addition figures jumped from a mere 8,990 MW in the 10th plan period (2002/2007) to about 40,900 MW in the 11th plan (2007/2012) (See Table 2.1 and Figure 2.1).

Table 2.1: Cumulative Installed Coal-based Capacity vis-à-vis Total Installed Capacity from 1947 to 2012				
(All figures in MW)				
Month and year	Total Capacity Added during the Plan	Cumulative Installed Coal-based Capacity	Total Installed Capacity	% Share
December 1947	756	756	1362	55.5
December 1950	248	1004	1713	58.6
March 1956 (Ist plan)	593	1597	2886	55.3
March 1961 (2nd Plan)	839	2436	4653	52.4
March 1966 (3rd Plan)	1981	4417	9027	48.9
March 1974 (4th Plan)	4235	8652	16664	51.9
March 1979 (5th Plan)	6223	14875	26680	55.8
March 1985 (6th Plan)	11436	26311	42585	61.8
March 1990 (7th Plan)	14925	41236	63636	64.8
March 1997 (8th Plan)	12918	54154	85795	63.1
March 2002 (9th Plan)	7977	62131	105046	59.1
March 2007(10th Plan)	8990	71121	132329	53.7
March 2012 (11th Plan)	40901	112022	199877	56.0

Figure 2.1 presents the same data as given in Table 2.1.

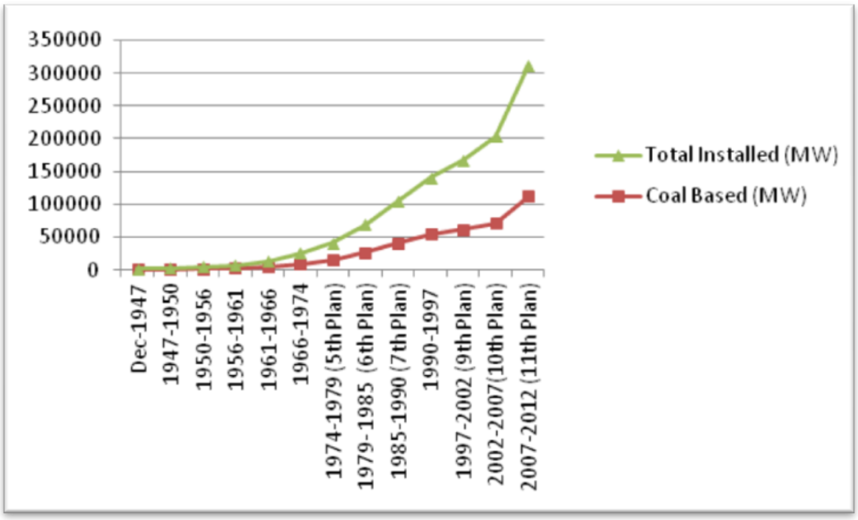

Figure 2.1: Cumulative Installed Coal-based Capacity vis-à-vis Total Installed Capacity from 1947 to 2012

PLANNED COAL-BASED CAPACITIES IN THE 12TH AND 13TH FIVE-YEAR PLAN PERIODS

According to the National Electricity Plan, (NEP), 2012, released by the apex electricity planning authority in India, the Central Electricity Authority (CEA), there are about 124,455 MW of coal-based power projects under various stages of approval. However, even CEA in its projections in the NEP, 2012, has used scenarios for mapping capacity additions in the 12th (2012/2017) and the 13th (2017/2022) five-year plan periods. Recognizing the need for climate-positive actions, CEA has developed three scenarios of capacity addition for the two periods. Scenario 1 is called 'Low RE, Low Gas' (LREG) scenario and projects a predominantly coal-based energy mix. Scenario 2, 'Low RE, High Gas', projects substitution of some coal-based capacity with the more climate-friendly gas. Scenario 3 'High RE, High Gas' tries to maximize substitution of coal-based generation with RE and gas. All the proposed scenarios also include decommissioning of about 4,000 MW of coal-based capacities in each plan period.

To highlight the extremities of projections, we will be using Scenario 1, 'Low RE, Low Gas', and Scenario 3, 'High RE, High Gas'. Table 2.2 summarizes the projected coal-based capacity addition figures for the two scenarios across the 12th and 13th Five-Year Plans.

Table 2.2: Projected Coal-based Capacity (MW) for LREG and HREG Scenarios

Sr. No.	Scenario 1: Low RE, Low Gas (all figures in MW)			
	Parameter	12th Five-Year Plan (2012/2017)	13th Five-Year Plan (2017/2022)	Total
1	Installed Capacity at the beginning of the Plan	112022	170717	—
2	Proposed new generation capacity	66600	49200	115800
3	Decommissioning	4000	4000	8000
	Scenario 3: High RE, High Gas (All figures in MW)			
	Parameter	12th Five-Year Plan (2012/2017)	13th Five-Year Plan (2017/2022)	
4	Installed capacity at the beginning of the Plan	112022	159422	—
5	New generation	51400	34000	85400
6	Decommissioning	4000	4000	8000

Interestingly, the figures seem to suggest that even under the HREG scenario, the potential to reduce coal-based capacities would only be to the tune of 30,400 MW (115800–85400) across the 12th and 13th five-year plan period and that a minimum of 85,400 MW of new coal-based capacity addition is almost an inevitability!

PROJECTION OF COAL-BASED CAPACITY ADDITION SCENARIOS UP TO 2032

In the absence of validated data giving the breakdown of the proposed capacity year-by-year upto 2032, the only way to arrive at such figures is to assume that the break-up of the plan period capacities and decommissioned capacities are distributed evenly across the duration. Further, to project new coal-based capacity addition plans for the 14th (2022/2027) and the 15th (2027/2032) five-year plan periods, an annual capacity addition growth rate of 7% is assumed for the LREG scenario. This growth rate is equated to the probable GDP growth rate of India assuming that the growth momentum is sustained. For the HREG scenario, the coal-based capacity addition growth rates assumed for the 14th and the 15th plan periods are 3% and 2% respectively. This decrease in growth rates necessarily assumes forcings brought about by increasingly stringent climate regulations, import pressures, and increasing coal prices and other potential risks. The total capacity due for decommissioning during the plans is assumed as 8,000 MW in each plan. Based on the above assumptions, WISE has summarized the projected capacity additions for the 14th and 15th plan periods for the two scenarios in Table 2.3.

Table 2.3: WISE Estimates of Projected Coal-Based Capacity Additions (MW) in the 14th and 15th Plan Periods (LREG and HREG Scenarios)

Scenario 1: Low RE, Low Gas (All figures in MW)		
Parameter	14th Five Year Plan (2022/2027)	15th Five Year Plan (2027/2032)
New generation	79288	111206
Decommissioning	8000	8000
Annual growth rate	7%	7%
Scenario 3: High RE, High Gas (All figures in MW)		
Parameter	14th Five Year Plan (2022/2027)	15th Five Year Plan (2027/2032)
New generation	21675	13645
Decommissioning	8000	8000
Annual growth rate	3%	2%

In broad terms, the projections envisage two distinctly different routes to capacity additions. The LREG scenario envisages continuing reliance on coal. In the HREG scenario, the projections imply substantial lowering of coal-based capacity additions and substitution of coal with other technologies. In both the cases, the percentage contribution of coal in capacity additions is expected to reduce over time because of forcings brought about by fuel shortage and high prices. Table 2.4 gives the cumulative capacity addition upto 2032 for the LREG and HREG scenarios. Beyond 2022, the report recommends the HREG scenario wherein only 21,675 MW and 13,645 MW of coal-based capacity would need to be added during the 14th and 15th plan periods respectively.

However, one thing is clear: irrespective of fuel availability, tightening of environmental and climate regulations will increasingly make way for new and more efficient technologies that will change the conversion factors used for converting gross capacity additions into meaningful metrics like coal requirements and specific emissions.

Table 2.4: Coal-based Cumulative Capacity Additions up to 2032 for LREG and HREG Scenarios				
Scenarios	Low RE, Low Gas (MW)		High RE, High Gas (MW)	
Plan Period	Installed during the plan period	Total installed (by the end of the plan period)	Installed during the plan period	Total installed (by the end of the plan period)
11th Plan (2007/2012)	40901	112022	40901	112022
12th Plan (2012/2017)	66600	174622	51400	159422
13th Plan (2017/2022)	49200	219822	34000	189422
14th Plan (2022/2027)	79288	299110	21675	211097
15th Plan (2027/2032)	111206	410317	13645	224742

ULTRA MEGA POWER PROJECTS

Ultra Mega Power Projects (UMPPs) are large coal projects, about 4,000 MW each, envisaged to meet the power requirements of a number of states. These projects are being developed on a build-own-operate (BOO) basis, with the developer being chosen according to the competitive bidding guidelines. Power Finance Corporation (PFC) is the nodal agency under this initiative. UMPPs use super critical technology with a view to achieving high levels of fuel efficiency, resulting in saving fuel and lowering GHG emissions per unit of electricity. These projects have been allotted coal for captive use or allowed use of imported coal if located near coastal areas. For development of UMPPs, the Ministry of Power is playing a crucial role by coordinating with central ministries and agencies for ensuring coal linkages, environmental and forest clearances, and water linkages; facilitating power purchase agreements (PPAs); seeking support from respective states; and monitoring progress. A total of 16 UMPPs have been envisaged, of which 4 have been approved (Table 2.5), while others have been delayed owing to various reasons, including increase in the prices of imported coal, delays in environmental clearances and other delays by the state governments. Table 2.6 lists the UMPPs yet to be awarded power off-take agreements.

Table 2.5: UMPPs Approved and their Capacities			
UMPP	State	Developer	Tariff (Rs/kWh)
Mundra	Gujarat	Tata Power	2.26
Sasan	Madhya Pradesh	Reliance Power	1.196
Tilaiya	Jharkhand	Reliance Power	1.77
Krishnapatnam	Andhra Pradesh	Reliance Power	2.333

Table 2.6: UMPPs yet to be Awarded Power Off-take Agreements	
UMPP	Status
Chhattisgarh UMPP, Sarguja	Bidding process has started
Odisha UMPP, Sundargarh	Bidding process has started
Tamil Nadu, UMPP, Cheyyur	Site clearance required
Andhra Pradesh (2nd UMPP)	Proposed
Odisha (additional UMPP 1)	Proposed
Odisha (additional UMPP 2)	Proposed
Maharashtra UMPP	Land clearance required
Karnataka UMPP	Land clearance required

PROJECTION OF ENERGY GENERATION FROM COAL-BASED PLANTS

The Central Electricity Authority works out PLF of coal-based power projects on the basis of capacity which was operational during a particular year. The operational capacity (as against the installed capacity) depends on the availability of required resources like coal or water, closure due to outages or extended maintenance, etc. The operational capacity in 2011/12 was about 82.5%, and in the previous five years typically ranged from 82.1% to 85.1%. According to the CEA, the average PLF of coal-based thermal power projects (based on operational capacity) in 2011/12 was 73.46%. However, according to WISE, the PLF should be worked on the basis of average installed capacity. The installed capacity of coal-based projects at the beginning of the 11th plan was 93,918 MW and at the end was 1,12,022 MW and the average of the two viz. 1,02,976 MW is considered here as the installed capacity of the 12th plan period. Based on this average installed capacity and annual electricity generation of 584 BU capacity, the PLF of coal-based power projects in 2011/12 works out to about 65%.

Table 2.7: Coal-based Power Generation for the LREG and HREG Coal Scenarios up to 2032				
Scenarios	Low RE, Low Gas (BU)		High RE, High Gas (BU)	
Plan period	Generation during the plan period	Annual generation (by the end of the plan period)	Generation during the plan period	Annual generation (by the end of the plan period)
12th Plan (2012-2017)	4466	1047	4186	954
13th Plan (2017-2022)	6070	1325	5324	1139
14th Plan (2022-2027)	8389.4	1905	6290	1320
15th Plan (2027-2032)	11667	2652	6885	1417

For estimating generation from the projected installed base, it is assumed that marginal improvements in operational availability and operating PLFs may increase the gross capacity utilization factor (CUF i.e. generation in terms of installed capacity) for old capacities up to 67%. For new capacities, a gross CUF of 70% (74% unit PLF and 95% availability) is assumed. Based on the given assumptions, the estimates for coal-based generation in BU for the LREG and HREG scenarios upto 2032 from the 12th to the 15th plan periods are provided in Table 2.7.

Incidentally, if we compare the coal generation figures with the total energy requirement as given in the 18th Electric Power Survey by the end of the 11th, 12th, and 13th plan periods, the following scenario emerges (Table 2.8).

Table 2.8: Projected Coal-based Generation with Projected Total Energy Demand for LREG and HREG Scenarios (As per 18th Electric Power Survey)

	End of the 11th Plan (2011/12)	End of the 12th Plan (2016/17)	End of the 13th Plan (2021/22)
Demand as given in the 18th Electric Power Survey (BU)	918	1348	1872
Low RE, Low Gas			
Actual/Estimated coal generation (BU)	560	1047	1325
% share	61%	78%	71%
High RE , High Gas			
Actual/Estimated coal generation (BU)	560	954	1139
% share	61%	71%	61%

The estimates based on the generated scenarios suggest that even the climate-friendly scenario of High RE, High Gas, may imply an increase in the share of coal in total generation from 61% currently to about 71% by the end of the 12th plan period. However, it is worth noting that from the perspective of energy mix, both the scenarios indicate a lower share of coal in the generation mix in the 13th plan period (as compared to the 12th plan period).

PROJECTION OF COAL REQUIREMENTS

According to the Report of the Working Group on Coal and Lignite (November 2011), the specific coal consumption (SCC), that is the weight of coal required per unit generation (kg/kWh) for 2011/12 was 0.740 kg/kWh. The projected SCC at the end of the 12th plan period was 0.697 kg/kWh. For the present calculations, we have assumed the specific coal consumption to be 0.700 kg/kWh for existing capacities. However, as the new capacities planned in the 12th and 13th plan periods and beyond are expected to use supercritical or other high-efficiency technologies, the specific coal consumption for new capacities is taken as 0.600 kg/kWh.

Based on the above assumptions, the total coal requirements up to 2032 are shown in Table 2.9 and Figure 2.2.

Table 2.9: Projected Coal Requirements for the LREG and HREG Scenarios upto 2032				
Scenarios	Low RE, Low Gas (million tonnes)		High RE, High Gas (million tonnes)	
Plan period	Requirement during the entire plan period	Annual requirement (at the end of the plan period)	Requirement during the entire plan period	Annual requirement (at the end of the plan period)
11th Plan (2007–2012)	NA	600	NA	600
12th Plan (2012–2017)	3003	692	2835	636
13th Plan (2017–2022)	3954	856	3507	745
14th Plan (2022–2027)	5319	1199	4060	847
15th Plan (2027–2032)	7263	1642	4394	900

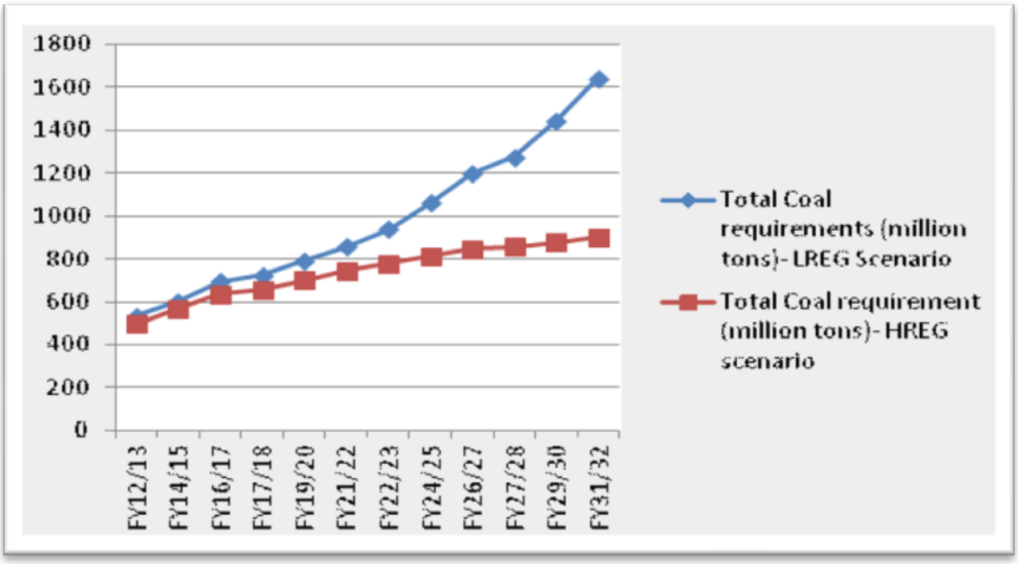

Figure 2.2: Projected Coal Requirements for the LREG and HREG Scenarios (million tonnes) up to 2032

Although the projected coal-based capacities of 170,000 MW, under various stages of approval project a rosy picture, past experience suggests that there is very little certainty about how many projects will be finally commissioned. Issues with coal linkages, import agreements, capital equipment shortages and Engineering, Procurement, Construction (EPC) capabilities severely hinder actual materialization and have led to cancellations and humungous delays in bringing the proposed capacities on stream.

"It is time for the policy planners to thoroughly analyze the possible risks of coal-based power sector planning and reconsider development of coal-based power projects beyond 2022."

Many of the projects touted as 'to be commissioned' are at a very preliminary stage in terms of actual construction activities, assured coal linkages (domestic and imported), or equipment receipts. The existing domestic fuel supply agreements guarantee only about 65% of the coal requirement on a regular basis. Furthermore, a bulk of the proposed capacity is under the state or central sector. Part of these capacities that do not have domestic linkages are actually assessing plans to import 100% coal at international prices. This level of dependence on imported coal is risky, not only from the cost perspective but also from the availability perspective. It is learnt that the recent increase in coal prices in Indonesia was effected through a presidential decree and Tata Power, despite owning a 30% share in one of the largest Indonesian coal mining companies, could not contest the decree, resulting in significant losses for the company. As coal prices are expected to increase even further, it is worth pondering if the projects evaluated on present cost dynamics will be commercially feasible at the time of their commissioning.

An even more worrying aspect is the possibility of international resource capturing or monopoly behavior of coal-rich countries, which may even result in drying up of imports, leaving India without any back-up for the huge loss of capacity. This availability deficit is evident even today as many coal-based plants are running on very short supply of coal. Already, such risks are being envisaged by profit-oriented corporates. Tata Power, one of the largest power players in India, has put all imported-coal-based power plants on hold. Most of the large banks have tightened lending norms to thermal power projects citing over-exposure and regulatory uncertainty. According to recent media reports, IDFC Bank has stopped lending to coal-based projects on the grounds of risks of fuel availability and price volatility of imported coal. Considering all the market signals, it is time for policy planners to thoroughly analyze the possible risks of coal-based power sector planning and reconsider development of coal-based power projects beyond 2022.

* * *

3. EXTERNALITIES OF COAL MINING, PROCESSING, AND COMBUSTION

The research team studied the adverse impacts that coal mining and power generation from coal-fired thermal plants have on the environment and people. The study delves into the various processes involved in coal mining, as these form the basis and the root cause of degraded lands, sullied waters, and polluted air, which in turn directly impact ecosystems, agriculture and biodiversity, health, and socio-economic development. It brings to the fore hard core facts and figures through case studies from different regions of the country, exposing the damage caused by coal mining and coal combustion on the four major spheres of the Earth: The Lithosphere (land), Hydrosphere (water), Biosphere (forests, flora and fauna) and the Atmosphere (air). It also exposes the various health and socio-economic impacts caused by coal on the people of the country.

IMPACTS ON THE LITHOSPHERE

Coal mining leads to all-round degradation of the lithosphere causing severe impacts due to drying up of water bodies, soil erosion, land subsidence, and desertification. Many such studies from major coal mining regions like Angul-Talcher and Medinipur in eastern India, Jharia-Ranigunj and Singrauli coal belt in northern and central India, and Raichur in southern India have been documented. Fly ash disposal has resulted in leaching of trace/heavy metals, causing severe soil contamination. Case studies from Indian power plants in Raichur (Karnataka), Singrauli (Madhya Pradesh), and Murshidabad (West Bengal), show the extent of damage.

Land Degradation

Fig 3.1 depicts the land degradation cycle caused due to coal mining. The consequences are dire, resulting in lush green landscapes being converted into mine spoils, besides large-scale destruction of forest cover and fertile agricultural lands. Mining has caused several green areas to become barren land. Heavy machinery and other heavy-duty mining activities have resulted in decrease in soil quality, apart from huge amounts of overburden and mining waste being dumped onto useful land.

Land degradation

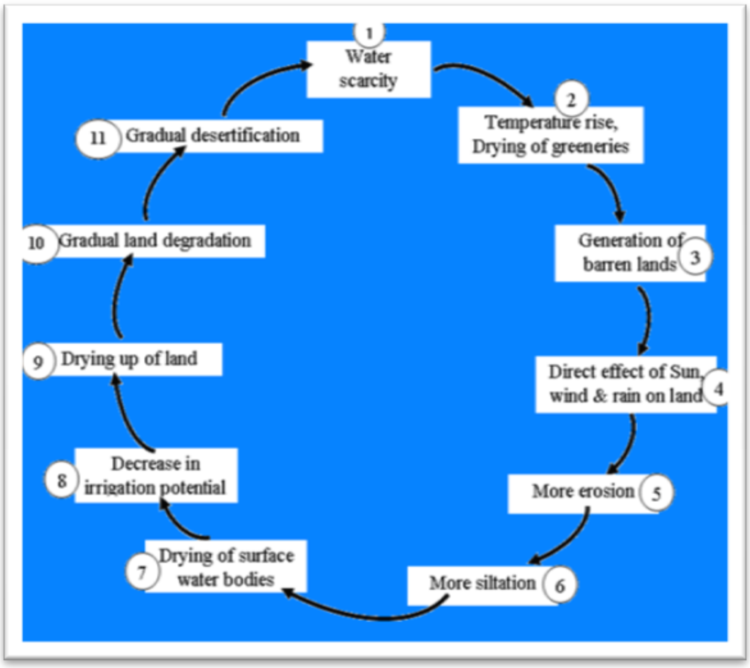

Figure 3.1: Land Degradation Cycle caused due to Coal Mining

Land Subsidence

India being a major coal producer has been facing severe problems of land subsidence in some of its underground coal fields. The duration of subsidence has two distinct phases: active and residual. Active subsidence refers to all movements occurring simultaneously with the mining operations, while residual subsidence occurs following the cessation of mining. The duration of residual subsidence is of particular importance as abandoned coal mines pose a significant higher risk of potential roof/pillar failure, resulting in subsidence. Severe cases of land subsidies has occurred in Haria and Raniganj coal belts in India.

Waste Disposal

The dumping of mine tailings and other reject material (referred to as overburden or OB), generated from opencast coal mines is considered as a major contributor to ecological and environmental degradation. The overburden is nutrient-poor, comprising loosely adhered particles of shale, stones, boulders, cobbles, etc., and is devoid of true soil character. Overburden also contains elevated concentrations of trace metals. A minimum period of 50 years to a century is required to restore the denuded land to its original verdant nature.

Dumping of Fly Ash

The combustion of powdered coal in thermal power plants produces fly ash, one of the numerous substances that cause air, water and soil pollution, disrupt ecological cycles, and set off environmental hazards. Depending upon the source and make-up of the coal being burned, the components of fly ash vary considerably. The presence of toxic elements are dependent on the specific type of coal bed, but may include one or more of the following elements or substances, ranging from trace amounts to several percent. These include arsenic, beryllium, boron, cadmium, chromium, chromium VI, cobalt, lead, manganese, mercury, molybdenum, selenium, strontium, thallium, and vanadium, along with dioxins and PAH compounds (Polycyclic aromatic hydrocarbons which are potent atmospheric pollutants that are produced as by-products of burning fossil fuels). The World Bank has cautioned that by 2015, India would require 1000 square kilometres or one square metre of land per person for disposal of coal ash. Currently, around 90 million tons of fly ash is being generated annually in India, occupying 65,000 acres of land. Such a huge quantity poses a lot of challenges, such as land usage, health hazards, and environmental dangers.

Destruction of Soil due to Accumulation of Trace Metals

Agricultural soils around the ash dumping sites of some thermal power plants were studied by some researchers to see if heavy metal such as Lead, Cadmium, Chromium, Arsenic, Copper, Zinc, Nickel, and Iron were present in the soil. A comparative analysis was then made between these soils and control soils (non-polluted soils) located far away from the power station. The toxic group metals of Lead, Cadmium, Chromium, and Arsenic were well differentiated by their higher values of variability and abnormal distribution from the biologically essential metals (micronutrients) such as Copper, Zinc, Nickel, and Iron. Statistical analysis revealed two probable sources responsible for affecting soils; the more dominant one contributed the toxic metals and less dominating source contributed the essential heavy metals. In control soils, no distinct separation of sources of metals was found. The values of toxic metals were higher in soils near the ash dumping sites, with large fraction of anthropogenic sources. In many cases, the soil was found to be largely contaminated by metals (predominantly higher within 2-4 km distance) to varying degrees from coal combustion by-products. It was also observed that concentration was maximum in the prevalent wind direction.

The relative land requirements for coal-based power projects and RE projects have been discussed in section 8 of this summary.

IMPACTS ON THE HYDROSPHERE

Severe cases of water pollution were observed in the states of Jharkhand, Madhya Pradesh, and Meghalaya, where water was found contaminated by leachates, total suspended solids, trace/heavy metals, and other effluents from mines, coal washeries, and thermal power plants. The consequent result was pollution of water for irrigation, drinking, and other domestic purposes, and overall destruction of water bodies. Water consumption/drawal for coal beneficiation and cooling of thermal plants was found to be a major concern, with studies depicting that 87.8% of total industrial water (clear) was required for thermal plants alone. This has resulted in affecting the hydrological balance, causing water scarcity in many parts of the country.

Consumptive Water Requirements

In the entire cycle of coal-based thermal power generation, water is required in large quantities in different operations.

- Coal washeries: This is water required for coal washing. The polluted water is being released into rivers with resultant impacts on human health and aquatic life for hundreds of kilometers downstream, including in the ocean, where the rivers meet the seas; additional costs for towns/cities to purify their drinking water; impact on cattle health and agriculture, including agricultural lands which are irrigated.
- Cooling water: water used in cooling towers of large thermal power stations, causing thermal pollution of water. Upto 60-100 litres of water are needed per kWh of electricity. Drying of rivers in summer due to water impoundment for power generation can occur.
- Make up water: water lost due to evaporation losses in the thermal cycle has to be made up with demineralized fresh water for the boilers; consumptive use of water can be 3-4 litres per kWh.
- Water for slurry: water is used as the slurry medium for carrying ash from power plants to ash ponds. Since about 200 gms of ash is generated per kWh of electricity, the requirement of water on an annual basis is huge, even if the water is partially recycled.

Table 3.1 gives us some examples of water requirement by major thermal power plants in Maharashtra.

Table 3.1: Some Examples of Water Requirement for Major Thermal Power Plants in Maharashtra

S.No	Name of Project	Plant Capacity (MW)	District	Water Requirement (Million m^3/year)
1	Chandrapur TPP	2340	Chandrapur	35.0
2	Khaperkheda TPP	840	Nagpur	20.4
3	Koradi TPP	1040	Nagpur	29.2
4	Wardha Warora TPP	540	Wardha	13.3

The average water requirement per MW is 23,000 m^3/year or 3.83 litres/kWh generated; the figures cited have been taken from the company websites. This obviously represents just the consumptive use of water and not water abstraction for cooling, if any. It is known that at least two major thermal plants in Maharashtra – Parli and Chandrapur – have faced temporary closure or backing down of power generation due to water shortage in summer or drought. This may be considered a portent for the future.

Water Pollution due to Coal Mining

- Acid mine drainage: caused due to leachates from opencast mining areas being carried as run-off from rainwater, affecting groundwater quality; water pumped out from underground mines also carries mineral leachates.
- Effect on surface water quality due to erosion: the increased erosion from opencast mines carry pollutants into surface water streams and then into rivers, affecting downstream health

and aquatic life caused due to turbidity, pH changes, changes in oxygen content, etc., of the water.

Studies by Singh, Bharti, showed heavy/trace metals in mine water samples collected from sites near Jharia, Ranigunj, and West Bokaro coalfields. Further, 35% of mine water from Jharia, 33% from Ranigunj, and 30% from Bokaro, showed a total hardness value greater than 600 milligrams/litre (mg/l), which is the maximum permissible limit as per IS-10500(BIS) 1991. According to the Central Pollution Control Board, Fluoride found in the mine waters of 7 mines of the Western Coalfields Ltd in Madhya Pradesh, 7 mines of South-Eastern Coalfields Ltd in Chhattisgarh, and mines located in Korba area of Chhattisgarh, and Sohagpur and Johila in Madhya Pradesh, were found to be in the hazardous range. Besides, concentrations of sulphates were also found to be exceeding their limits in mine waters of Western Coalfields Ltd.

A study carried out by A, Jamal et al. in Gorbi and Jhingurdah coal mines in Singrauli in north-eastern India found that mine water samples were highly acidic in nature, with heavy doses of toxic metals being discharged in the Bijul stream. All these factors have resulted in making the water sources in these areas totally unsuitable for domestic/drinking purposes. Acid mine drainage has caused severe deterioration of the water bodies in Jaintia hills, Meghalaya, making them turbid, highly acidic, and overall, affecting human as well as aquatic life in the area.

Destruction of River Basins

One direct quantitative consequence of large-scale water abstraction is that water will not be available for dilution of effluents / pollutants in these rivers, thereby magnifying the consequent pollutant impacts on human and animal health, freshwater aquatic systems, irrigation uses of water, and so on. In particular, these consequences occur even as climate change alters precipitation and river hydrology, and droughts increase the demand for water, particularly in agriculture. This will further magnify the risks of water availability for power generation as water is rendered a scarce resource, giving rise to social tensions.

The major river basins which will be affected due to destructive combination of activities related to coal mining and power generation in their catchments will be: Narmada, Tapti, Godavari (upper and lower catchment), Mahanadi and Koel (entire catchment), Brahmani, Baitarni and Subarnarekha (entire catchment), Damodar upper catchment, other east flowing rivers from Jharkhand (entire catchment) and Sone flowing into the Ganga. In plain words, the entire region of central India with rivers flowing in every direction will suffer long-term hydrological damage due to the combination of over abstraction and water pollution. These consequences have to be examined within the framework of the Water Pollution Control Act. Moreover, if water is abstracted from a river and effluents released into the river, the impact is greater due to higher concentration of effluents and lower quantities of water available for dilution. These impacts will be greatest during the summer months of lean flows in rivers.

According to Singh, Bharti, it was found that major rivers flowing through the state of Jharkhand have experienced decrease in total water cover by 28.83%, lowering of water table at an average rate of 2 cm/year, and decrease in natural surface drainage lines by 260 kms, due to 68 years of mining in the Jharia coalfields. The Damodar river located near the Jharia coalfields carries the effluents of around 14 coal washeries (located along the river) of Coal India Ltd, which discharge about 300–500 m^3 of effluents per day. Besides these 14 washeries, there are several others too and it has been found that generally, a single washery discharges about 40 tonnes of fine coal per day into the Damodar river. The washery effluents contained several trace elements in the range of 10 parts per million (ppm) to 300 ppm, higher than the permissible level of 5 ppm.

Destruction of Marine Ecosystems

In the case of coastal thermal plants mostly based on imported coal, while freshwater abstraction for cooling purposes is replaced by sea water for cooling, the fresh water consumptive requirement for power generation has to be accounted for, as saline water cannot be used in boilers. If fresh water has to be created through desalination, this will add to the auxiliary consumption of the station, thereby increasing the cost of electricity. Many of these are UMPPs of around 4,000 MW each. Thus, the cost impact on electricity cannot be ignored. Further, the release of hot water into the sea tends to affect marine habitats in the surrounding areas, denuding the local seas of all marine life forms, which, mostly being cold-blooded, are affected by sea water temperature rises of even a fraction of a degree Centigrade. The cooling water requirements vary between 57–190 litres per kWh of electricity generated for once-through cooling. Under standard operational assumptions, a 4,000 MW power plant during a 24-hour operational cycle would daily be pumping 5.76 billion litres of heated water into the adjacent sea, assuming 60 litres of cooling sea water per unit of electricity generated (the environmental implications of this thermal pollution have not been adequately worked out). It is unlikely that such a large quantity of cooling water will be stored in cooling ponds prior to its release into the sea as the land requirement would be huge. Moreover, the implications in terms of the Coastal Zone Management Act deserve to be further examined, considering that the thermal pollution will certainly affect local fisheries as well as any sensitive local marine habitats, which may also be affected by the incessant, large volume of air pollution (dealt with in a later section).

IMPACTS ON THE BIOSPHERE

Biospheric impacts include massive destruction of forests, flora and fauna. Large-scale destruction of forests has been observed in the states of Maharashtra (west), Jharkhand (north), and Odisha (east). Central India has been hit the most, with more than a million hectares of pristine forests under threat of destruction, besides coal mining impacting the survival of wildlife, especially tiger and elephant habitats/corridors in this region. In 2010, the Ministry of Environment and Forests identified "no-go" areas, indicating that dense forests in these areas should not be touched. But unfortunately, laxity of rules and pressure from coal lobbies may result in opening up these areas to coal mining, which could have serious future repercussions on the country's biosphere.

These will be cumulative impacts consisting of impacts from coal mining and impacts from thermal power generation. Forests will be considered at a generic level, including protected forests with dense canopy cover, reserve forests, sanctuaries and protected areas as well as habitats, endangered and endemic species and biodiversity.

Impacts on the biosphere due to coal mining include:

(i) direct deforestation due to forest clearance for coal blocks.
(ii) impact on surrounding forests due to overburden run-off.
(iii) bisection of forests for railway lines or roads; this often marks the beginning of further forest destruction.
(iv) impacts on wildlife due to blasting, animals being much more sensitive to sound.
(v) impacts on wildlife, resulting in wildlife deaths due to transportation corridors in forest areas/sanctuaries, both rail and roads.
(vi) impacts on forests/habitats due to mining dust from operations (blasting, loading, transportation, etc).
(vii) impacts on forests due to changes in water regimes, both surface and underground water sources.
(viii) potential impacts on forests due to land subsidence.

Impacts on forests, its flora and fauna due to coal-based power generation include:

(i) impacts due to air pollution – suspended particulate matter (SPM), sulphur oxides (SO_x) and nitrogen oxides (NO_x) are released into the atmosphere which can extend upto 50 miles (80 kms) downwind from thermal plants, conservatively estimated; for instance, coastal power plants on both the west coast and east coast will irreversibly affect the forest areas of both the Western Ghats and Eastern Ghats, both of which run parallel to the coastline.
(ii) impacts due to acid rain caused by CO_2, SO_x and NO_x being dissolved in precipitation.
(iii) impacts due to thermal (heat) pollution on downwind forests.
(iv) impacts due to flyash disposal/pollution on surrounding forests/habitats being carried by wind.
(v) impacts due to surface water abstraction/impoundment/thermal pollution of water.

According to a study conducted by Greenpeace India Society, a massive coal mining expansion is being planned in the North Karanpura valley located in the upper Damodar Basin, Jharkhand, one of the coalfields covered under the “no go” exercise. The entire coalfield covers an area of approximately 118,668 hectares, of which 41,457 hectares is forest cover. The “no-go” exercise covers 63 demarcated blocks, totalling 60,561 hectares, and 30 of these blocks are deemed to have sufficiently dense forest cover to be considered “no-go” blocks. The actual forest cover over these 63 blocks is 17,020 hectares or over 170 sq.km. The loss of this 170 sq.km will have serious repercussions on hydrology, wildlife, and forest-dependent livelihoods in Jharkhand.

A study by the Indian Institute of Remote Sensing, Dehradun, shows that actual mining lease area is not the perfect indicator of the total forest area impacted by mining. According to some estimates made by Greenpeace India Society, for every one unit of land that is under lease area (land that is being mined), the actual area affected is likely to be 10–20 units or even more. This figure becomes important when assessing the impacts that mining has on forests. In the coal mine affected areas of Jaintia Hills district of Meghalaya (Tiwary, R, K), the area under forest cover decreased by about 12.5% and there was about three-fold increase in mining area since 1975 to 2007. In the districts of Hazaribagh, Giridih, and Palamau in Jharkhand, rapid environmental deterioration is fast engulfing the forestry belt due to opencast coal mining activity (Agarwal S, K). The Angul-Talcher region has rich Sal forests, in addition to mixed forests as well as pure bamboo crops. According to Singh, Kumar, Prasoon, et al. mining activities has caused significant reduction in forest lands and agricultural land, leading to increase in barren lands.

"The environmental externalities of coal mining, processing, and combustion, and their combined effects on biotic resources, habitats, water availability, livelihoods, and health of people will also work as major limiting factors in the future. Especially, attempts to dilute the restriction of 'no-go' forest areas for mining of coal, will render large tracts in central Indian states barren—devastation for short-term gain when other alternatives were available."

Wildlife, in particular tigers and elephants, have fallen prey to coal mining in a big way. The Tadoba-Andhari Tiger Reserve (TATR) in Chandrapur, Maharashtra, is home to rare fauna (besides tigers). According to Greepeace India Society, mining is causing fragmentation of the forest and loss of connecting corridors between forests, endangering the lives of the tigers and other wildlife. In central India, more than one million hectares of standing forest is under threat of destruction from coal mining. All of India's major coalfields (those with coal reserves over one billion tonnes) fall within this area. These coalfields are 13 in number and account for over 25 billion of the 99.4 billion tonnes of proved non-coking coal reserves in the Gondwana basin. These coalfields will impact the survival of eight tiger reserves. Coal mining also poses a danger to the Asian elephant corridors. Recent decades have seen an increase in elephant-human conflict, besides increase in mortality rates of elephants due to coal mining related activities. This was found occurring in the Khinda village of Odisha.

Aquatic fauna and flora have been affected in the rivers of Jaintia hills, Meghalaya, (Sarma, Kiranmay), due to coal mining, which has rendered the waters unsuitable for life. Besides, vegetation in the area has also been harmed, reducing numbers, diversity, etc. A study carried out by Arun, P, R, et al. revealed that Chiku plantations in Dahanu, Maharashtra, have shown drastically declined yields in the past few years due to emissions from the Dahanu thermal power station. The Talabira coal mines in Odisha have also affected flora in the vicinity, with small herbs and medicinal plants being affected, and extinction of several others, besides affecting the growth of mango and cashew plants.

IMPACTS ON THE ATMOSPHERE

Impacts on the atmosphere due to thermal power generation are on a much wider scale as compared to coal mining. These impacts are far more subtle than the direct impacts of mining and power generation on land, water and forests. Due to the subtlety and widespread as well as long duration of these impacts, enormous research effort has been devoted in both US and Europe in terms of tracking and quantifying these impacts, in order to be able to incorporate the research findings into public decision-making processes.

There are 14 pollutants in the airborne stream emerging from the smokestacks of thermal power stations. These include the five classical pollutants namely sulphur dioxide (SO_2), NO_x, particulates, CO, and ozone; other toxic pollutants namely, Arsenic, Cadmium, Chromium, Mercury, Nickel, and Lead– all of them being heavy metals and injurious to human health when inhaled even in small quantities. The remaining pollutants are hydrocarbons.

Most current atmospheric dispersion models (based on modeling of smokestack emissions, with a grid size 10 km x 10 km) limit the damage estimation exercise to 100 km from the point of origin, though it is known that if 80% of the damage has to be captured in the modeling, the exercise has to be carried out for a distance greater than 1000 km from point of origin. In particular, the smallest particles emitted (less than 5 microns) can be transmitted beyond 5000 km and these are more dangerous to human health because they reach deeper into the respiratory system and are more difficult to dislodge.

The airborne emissions are classified into the following categories:

(i) Primary pollutants: particulates and sulphur dioxide.
(ii) Secondary pollutants: sulphur and nitrogen species, resulting in dry and wet deposition process (acid rain).
(iii) Photochemical oxidants such as ozone, formed due to atmospheric chemical reactions between hydrocarbons and oxides of nitrogen in the presence of sunlight.
(iv) Heavy metal pollutants – Arsenic, Cadmium, Chromium, Mercury, Nickel, and Lead – which will depend on coal characteristics.

The damage estimation modeling has to include all the space affected, all the time dimensions involved (i.e. well beyond the lifetime of the thermal plant, which is taken as 25 years) and all the affected groups i.e. people, property, forests and wildlife, water bodies and entire habitats. This necessarily implies that area-based life cycle models have to be developed and used in order to estimate the total impact over the lifetime of the project.

In brief, the following impacts and scale of ranges need to be considered:

(i) impacts on human health due to particulates, sulphur and nitrogen oxides and heavy metal pollutants, at a distance ranging from 100 km – 5000 km, over a time period beyond 25 years.

(ii) impacts of acid rain and ash deposition on croplands, forests, wildlife habitats, water bodies, fisheries and property.

(iii) impacts of heavy metal pollution through food pathways including crops, fish and animal products as well as drinking water.

(iv) many other secondary impact pathways.

Radioactive Emissions

Amongst the most disturbing of the latest research findings is the emerging link between radioactive emissions and coal combustion in thermal power stations. All coal contains traces of naturally occurring radioactive elements like uranium, thorium and potassium, and their concentration depends on the composition and geological history of the coal. Due to combustion, there is an increase in the concentration of radioactive elements in both the bottom ash and flyash particles. The main sources of radiation from coal combustion include not only uranium and thorium, but also their decay products such as radium, radon, polonium, bismuth and lead, as well as an isotope of potassium. The potential exposure and impact pathways include inhalation, deposition on soil and water bodies, and leaching into subsoil waters, and can take place through both the aerial pathway and ash storage and disposal. An estimated 1% of uranium in the coal is released through the escaping flyash into the atmosphere, the balance being concentrated in the remainder ash by a factor of several times. A recent instrumentation based study at the Chandrapur Super Thermal Power Station, the largest pithead power station in Maharashtra (4 x 210 MW + 3 x 500 MW) has confirmed the presence of radioactivity in the coal plant emissions products. Studies on concentration of radioactivity due to coal combustion have been available for over two decades. The further link with consequences for human health were made by Krylov, which shows that the largest radiation doses to the population living in regions around thermal power plants are caused by the passage of a plume of radioactive emissions and contamination of ground surface resulting from this passage. Moreover, the smaller the size of coal ash particles, the higher the specific radioactivity of this ash; therefore, fly ash emitted from power stations has higher radioactivity than ash deposited in the precipitator. Recently, based on apprehensions regarding the impacts of radioactivity from combustion of coal in thermal power stations, the National Green Tribunal has directed the Ministry of Environment and Forests (MoEF) to look into… "The long term impacts caused by nuclear radiation from thermal power projects—particularly the cumulative effect of a number of thermal power projects located in the area—on human habitation, and environment and ecology. The MoEF shall include in the Terms of Reference of all future projects, the proponent to furnish details of possible nuclear radioactivity levels of the coal proposed to be used for the thermal power plant."

Studies conducted by the Central Pollution Control Board showed that Dhanbad in Jharkhand ranks 13th among 88 industrial areas,

"Amongst the most disturbing of the latest research findings are the emerging link between radioactive emissions and coal combustion in thermal power stations. All coal contains traces of naturally occurring radioactive elements like uranium, thorium, potassium, etc."

and is one of the most critically polluted cities in India, due to coal mining carried out here extensively. Overall mean PM10 particle levels (measuring 10µm or less, and likely to be inhaled by humans and cause harm to them) was 193 ± 79 $\mu g/m^3$, ~3 times higher than the annual PM10 (60 $\mu g/m^3$) National Ambient Air Quality Standards (NAAQS), 2009, prescribed by the Central Pollution Control Board, and around 9–10 times higher than the annual PM10 air quality guideline (20 $\mu g/m^3$) set by the World Health Organization (2006). Further, Block II OCP, one of the largest opencast projects of coking coal in Dhanbad showed that the total amount of dust calculated by the emission factor data was 9368.2 kilogram/dust (kg/d), the cause of severe air pollution. In the Jharia coalfields, total solid particulate (TSP) concentrations exceeded the permissible limit specified by the Central Pollution Control Board at all locations viz industrial, residential, and hospital zones. PM10 concentrations too were high.

According to the Indian Network of Climate Change Assessment (INCCA), based on the average net calorific value of coal and assuming 90% of coal utilization in the fuel mix, it is estimated that the contribution of coal in CO_2 emissions would be 644 million tonnes. CO_2 emissions from coal and lignite-based plants (86 in number) studied from April 2007 to March 2008 was 455 million tonnes. If the carbon lost in ash is not considered, then current estimates from these same 86 plants is estimated to increase to 546 million tonnes and total emissions from all thermal plants would be 677 million tonnes (close to the 644 million tonnes mentioned in the study). Another major air polluter, NO, was studied and it was found that all-India and region-wise estimates of annual NO emissions have shown an increase from 1.5 million tonnes in 2001/02 to 2.3 million tonnes in 2009/10.

Coal-fired plants have been found to be the second largest source of mercury emissions. A typical 100 MW power plant can emit over 10 kg of mercury in a single year. The five giant super thermal power plants in Singrauli which supply 10% of India's power are responsible for generating 16.85% i.e. 10 tonnes per annum of total mercury emissions into the atmosphere. If this is the norm, then a huge amount of mercury is being released into the atmosphere.

SOCIAL AND HEALTH IMPACTS OF COAL MINING AND POWER GENERATION

Social Impacts

This is a sensitive issue because many of the affected people would be protected by the Sixth Schedule of the Constitution specifically designed to protect tribals and dalits. In addition, they would have rights under the Resettlement and Rehabilitation policy, the Panchayat [Extension to Scheduled Areas] Act (PESA), 1996, mineral rights and forest rights, etc. Even if these categories of people are not displaced or their lands acquired, consideration has to be given to the impacts on their health due to air and water pollution in their immediate neighbourhood areas, negative impacts on their livelihoods due to adverse impacts on agriculture, forests, local wildlife and local fisheries. These would be cumulative area-level impacts, super positioning impacts from both coal mining and thermal power generation, combined with transportation impacts and impacts of water impoundment. While this study is confined to coal mining and the power sector, there would be further impacts from the mining of other minerals, their beneficiation and downstream metallurgical operations. It may be noted that many of the affected communities survive off marginal, unirrigated agriculture on forest fringe lands, eking out an existence partly from the land, partly from the forests, and partly from labour performed under feudal conditions. For such a marginalized populace, the further loss of land, forests, water, livelihood, health and productivity can be devastating, especially when coupled with the escalating impacts of climate change.

An Expert Group of the Planning Commission, set up to look into development challenges in extremist affected areas, has recommended "…Constitutional rights of the tribals…should be fully protected." Foreseeable impacts on such communities will include malnutrition, starvation, break up of communities and clans, resulting in out-migration. Particularly in the case of tribal communities, individual members of tribes can fall back on community solidarity and resilience in times of distress, through sharing; even this will be denied to them when communities break up and members migrate in search of livelihood. Members of these communities also do not have the requisite level of skills or knowledge to find any but the most meagre employment at the bottom of the industrial ladder, even in a labour surplus economy. In short, the destruction of environment and forests will result in an irreversible destruction of tribal and forest-based communities. Also, the country has not reached a level of prosperity wherein it can extend any form of social safety net to vast numbers – a safety net consisting of guaranteed access to food and water, access to housing, health and education, access to decent and sustainable employment and security of existence, paid out of public resources.

Coal mining has caused immense trauma to the tribals and indigenous people living near the Mahanadi coalfields in Odisha. Of the 19 affected villages, 130 odd families were displaced and left with no place to live, resulting in a life of penury and hardship. A study conducted by Sharma, R, N, found that in Singruali, Madhya Pradesh, construction of power projects in the 1980s by the National Thermal Power Corporation and the Uttar Pradesh State Electricity Board, resulted in 20,504 landowners losing their lands, displacing 4,563 families. Post-2006 saw the third phase of land acquisition for setting up five more super thermal plants, which may further displace some 10,000 odd families. The Singareni colleries in Andhra Pradesh, which are mostly opencast mines have destroyed several villages in the vicinity, due to heavy blasting in the mines. Since 2010, the villages have been totally abandoned, thus causing displacement of thousands of villagers.

A report prepared by the Motivational Organization for Rural Development (MORE), showed that the Singareni colleries have caused several tribals living in the nearby villages to lose their livelihoods. Traditional occupations such as collection of *Beedi* leaves, cattle rearing, etc., which were important sources of livelihood for the tribals ceased, leaving them to live a life of hunger and misery. It was also seen that Singareni established 6 new mines on 16,000 hectares of rich, agricultural land, resulting in tribals losing out on this vital activity (agriculture) for earning their living, besides facing displacement.

Health Impacts

Diseases due to Air Pollution

In Singruali, Madhya Pradesh, studies showed that mercury emissions from thermal plants, especially fly ash was affecting the health of the local people, with mercury contamination found in their blood samples. In Eastern India, nine types of conventional and mechanized coal mines were assessed, and it was found that different mining operations were exposing the workers to severe dust pollution, causing major respiratory problems like silicosis (caused by inhaling silica dust). In the Ib Valley in Odisha, dust pollution was found to be directly associated with tuberculosis. In 2005, the suspected cases of tuberculosis were 59.02%, increasing to 60.85% and 65.91% in 2006 and 2007 respectively. Besides, people were also suffering from silicosis, causing serious problems such as impairment of the immune system. Long-term exposure to silica has been linked to pulmonary tuberculosis as well as chronic kidney diseases, besides the deadly Coal Miners Pneumoconiosis (also called *Black Lung* disease).

Diseases due to Water Pollution

Villagers living close to the Talabira-I mines in Odisha were found to be severely affected by diseases related to water contamination caused by coal mining. Dermatitis, diarrhea, malaria, joint pain and gastroenteritis, etc., were found rampant in these villages. Further, the water was so badly contaminated that it was not even fit for bathing, leave aside drinking purposes.

Diseases due to Noise Pollution

Noise pollution is the second biggest occupational hazard in the Indian mining industry. In the Ib Valley opencast mines of Odisha, prolonged exposure to noise caused by heavy earth-moving machineries, etc., revealed that more than 40% of the workers were suffering from hearing related problems, besides headache, loss of concentration, and cardiovascular stress. It has been found that prolonged exposure to noise results in permanent damage to the auditory nerve, causing noise-induced hearing loss. Surveys carried out at Nandira colliery, Talcher, Odisha, showed that the level of noise was higher than 90 decibels, which is the acceptable noise limit.

Deaths caused by Pollution from Coal-based Thermal Power Plants

A study conducted by the Conservation Action Trust, Mumbai, relating to mortality and morbidity due to coal-based power generation showed alarming results. The study calculated health impacts for the base year 2010, by overlaying the gridding population with the modeled pollution from the coal-fired power plants. Total premature mortality for the range of mortality risks ranged between 80,000 and 115,000 per year. They claim that the estimation of the premature deaths and morbidity cases are conservative. Not included in the analysis are the impacts of the trace metal concentrations in the flue gas, which could further aggravate the overall implications of power plants.

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4. BALANCE OF PAYMENTS CONSTRAINT AS A MAJOR RISK FACTOR FOR COAL IMPORTS

Energy imports, along with imports of gold and silver have been straining India's balance of payments (BoP) for sometime now. The unit price of net import of fossil fuel in tonnes of oil equivalent (TOE) has increased in nominal rupees and dollar terms at 10.23% per annum and 5.75% per annum respectively and at 3.41% per annum in constant 2004/05 rupee prices (Table 4.1).

Table 4.1: Unit Price of Net Imports for Fossil Fuels Combined

Year	Rupees per TOE	Dollars per TOE	Constant Rupee per TOE
1989/1990	2279.50	140.50	5290.87
1994/1995	4647.94	148.14	8527.03
1999/2000	7461.60	172.20	9870.50
2004/2005	11713.76	261.30	11713.76
2010/2011	20167.72	444.15	12265.30
Growth rate	10.23%	5.75%	3.41%

As a result of the price rise as indicated above, India's total net energy import bill has grown at an alarming rate of 19.92% per annum, leading to an increase of almost 55 times in the past two decades (Table 4.2). India's energy import bill as a share of gross domestic product (GDP) exceeded 8% in 2008/09 and still exceeds 7% in current prices. This is higher than that of Germany (3.3%) and Japan (4.4%), despite the fact that their energy import dependence is far higher than that of India. India runs a trade deficit while both Germany and Japan run trade surpluses.

Table 4.2: Net Import Bill for Fossil Fuels Combined

Year	In Current Million Rupees	In Current Million Dollars
1989/1990	61204.90	3772.54
1994/1995	193508.57	6167.76
1999/2000	596017.04	13754.15
2004/2005	1193172.50	26614.28
2010/2011	3314655.90	72998.30
Growth Rate	19.92%	15.05%

This is the alarming backdrop for continuing increases in coal imports. There has been a drawdown of foreign exchange reserves in the recent past, with the current account deficit (CAD) reaching 4.2% of GDP in 2011/12.

CURRENT ACCOUNT DEFICIT

Current account deficit (CAD) increased significantly in 2011/12 to reach US $78 billion, as against US $46 billion in 2010/11 (a 70% increase in one year—See Fig 4.1). This increase was largely due to the higher trade deficit. As a percentage of GDP, CAD increased from 2.8% in 2009/10 and 2.7% in 2010/11 to 4.2% in 2011/12. Historically, on an average, CAD increased 36% annually during 2000/01 to 2011/12 (Figure 4.1). In the same period, trade deficit increased by 28% and net invisible receipts by 24%.

The high level of CAD in proportion of GDP is alarming for India. If the rising trend of trade deficit continues with comparatively slower increase in invisibles, CAD will increase significantly.

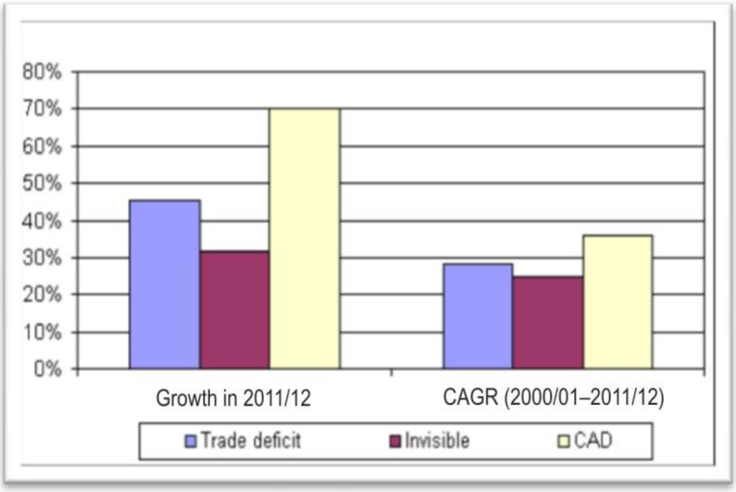

Figure 4.1: Increase in CAD relative to GDP

BALANCE OF PAYMENTS AND FOREIGN EXCHANGE RESERVES

Overall balance of payments became negative in 2011/12 after two successive years of positive performance. In 2011/12, the overall negative balance was $12.8 billion, from a positive balance of $13.1 billion a year earlier.

Foreign exchange reserves stood at $294.4 billion at the end of 2011/12 (Table 4.3—US$10 billion less from the 2010/11 level (3% reduction). The annual average growth rate of reserves were 20.53%, 18.46%, and 11.69% during 1990/91 to 2011/12, 2001/02 to 2011/12, and 2005/06 to 2011/12 respectively.

The change in foreign exchange reserves has happened on the basis of change in balance of payments (BoP) and gain / loss in terms of valuation. In 2010/11, the gain in foreign exchange reserves was US$25.7 billion, but in 2011/12, that was reduced by US$10.4 billion. However, in valuation terms, there was a marginal gain in reserves in 2011/12 but the foreign exchange reserves fell because of high deficit in the BoP account. The balance of payments and the change in valuation were positive in 2009/10 and 2010/11. The scenario changed in 2011/12 because of a considerable decrease in the BoP account, along with marginal gains in terms of valuation.

Table 4.3: Change in Foreign Exchange Reserves ($ billion)		
Particulars	2010/11	2011/12
Foreign exchange reserves	304.8	294.4
Change in reserves	25.7	–10.4
BoP basis	+13.1	–12.8
Valuation basis	+12.6	+2.4

From the above analysis, it is clear that the overall BoP decreases for a relatively high CAD vis-*à*-vis low capital account surplus. Low gain in terms of valuation along with BoP account deficit reduced India's foreign exchange reserves. If this trend continues, the resultant foreign exchange reserves will not be sufficient to fund the higher imports of energy goods on a continuous basis.

ENERGY IMPORTS AND BOP RISKS: FOUR SCENARIOS

Based upon the analysis of imports of energy goods and the projections of trade balance in energy goods up to 2030/31, four probable BoP scenarios have been developed (Table 4.4).

The scenarios reflect the future condition of India's BoP account if the projected trends in the import of energy goods continue, besides trade in non-energy goods and in invisibles. The resultant figures are derived with some critical assumptions, and the results are very specific to those assumptions. The projected trade balance in energy goods is considered to be the same in all the scenarios.

Scenario 1 shows the effect of projected trade balances in energy goods on BoP account, keeping all other items like trade balances in non-energy goods, invisibles, and capital account the same at their 2011/12 level (Table 4.4).

Scenario 2 assumes that only trade balances of non-energy goods will be zero from 2016/17 onwards. All other assumptions are the same as those for Scenario 1 (Table 4.5).

Scenarios 3 and 4 assume some specific growth rates of trade balance in non-energy goods and invisibles (Tables 4.6 and 4.7). Trading pattern of merchandise in India and its growth were analysed separately, and the trade balance of energy goods and non-energy goods were also analyzed separately. For trade balance in non-energy goods, the growth pattern of their exports and imports are considered separately. The historical growth rates of the export of primary goods and manufacturing goods have been taken for calculating the growth in exports of non-energy goods. The growth rate of exports of non-energy goods is taken as 18.13%, which is the weighted average growth rate of exports of primary goods and manufacturing goods. Similarly, for import, the weighted average growth rates of import of other bulk and non-bulk goods is taken for calculating the future growth in imports of non-energy goods, which is 20%, excluding gold and silver. Growth rate of imports of gold and silver, which has significantly increased only in recent years, is taken as 3%.

Receipts from invisibles (including services) always act as a cushioning factor to the trade deficit. Considerable growth of invisibles can actually reduce the impact of the increasing trade deficit and can maintain the current account balance at a sustainable level. In Scenario 3, 10% growth rate of invisibles has been considered, which is lower than the historical growth rate, as the growth in invisibles' receipts is bound to be uncertain due to the global crisis and service sector business policies of other countries. A higher growth rate of invisibles (19%) is considered for Scenario 4. The GDP growth rate is taken as 7% for all the four scenarios.

Table 4.4: Results of Balance of Payments: Scenario 1

Particulars	2011/12	2016/17	2021/22	2030/31
A. Energy trade balance	–116.72	–164.01	–296.02	–889.00
B. Non-energy trade balance	–73.04	–73.04	–73.04	–73.04
I. Trade balance (A + B)	–189.76	–237.05	–369.06	–962.04
II. Invisibles, net	111.60	111.60	111.60	111.60
III. Current account (I + II)	–78.16	–125.45	–257.46	–850.44
IV. Capital account	65.32	65.32	65.32	65.32
V. Overall balance (III + IV)	–12.84	–60.13	–192.14	–785.12
As a percentage of GDP				
Trade balance		–9.15%	–10.15%	–14.39%
Current account		–4.84%	–7.08%	–12.72%
Capital account		2.52%	1.80%	0.98%

Table 4.5: Results of Balance of Payments: Scenario 2

Particulars	2011/12	2016/17	2021/22	2030/31
A. Energy trade balance	–116.72	–164.01	–296.02	–889.00
B. Non-energy trade balance	–73.04	0.00	0.00	0.00
I. Trade balance (A + B)	–189.76	–164.01	–296.02	–889.00
II. Invisibles, net	111.60	111.60	111.60	111.60
III. Current account (I + II)	–78.16	–52.41	–184.42	–777.40
IV. Capital account	65.32	65.32	65.32	65.32
V. Overall balance (III + IV)	–12.84	12.91	–119.10	–712.08
As a percentage of GDP				
Trade balance		–6.33%	–8.14%	–13.30%
Current account		–2.02%	–5.07%	–11.63%
Capital account		2.52%	1.80%	0.98%

Table 4.6: Results of Balance of Payments: Scenario 3				
Particulars	**2011/12**	**2016/17**	**2021/22**	**2030/31**
A. Energy trade balance	–116.72	–164.01	–296.02	–889.00
B. Non-energy trade balance	–73.04	–143.78	–364.19	–2409.83
I. Trade balance (A + B)	–189.76	–307.79	–660.21	–3298.83
II. Invisibles, net	111.60	179.73	289.46	682.54
III. Current account (I + II)	–78.16	–128.06	–370.75	–2616.29
IV. Capital account	65.32	65.32	65.32	65.32
V. Overall balance (III + IV)	–12.84	–62.74	–305.43	–2550.97
As a percentage of GDP				
Trade balance		–11.88%	–18.16%	–49.36%
Current account		–4.94%	–10.20%	–39.15%
Capital account		2.52%	1.80%	0.98%

Table 4.7: Results of Balance of Payments: Scenario 4				
Particulars	**2011/12**	**2016/17**	**2021/22**	**2030/31**
A. Energy trade balance	–116.72	–164.01	–296.02	–889.00
B. Non-energy trade balance	–73.04	–143.78	–364.19	–2409.83
I. Trade balance (A + B)	–189.76	–307.79	–660.21	–3298.83
II. Invisibles, net	111.60	266.32	635.53	3041.28
III. Current account (I + II)	–78.16	–41.48	–24.68	–257.55
IV. Capital account	65.32	65.32	65.32	65.32
V. Overall balance (III + IV)	–12.84	23.84	40.64	–192.23
As a percentage of GDP				
Trade balance		–11.88%	–18.16%	–49.36%
Current account		–1.60%	–0.68%	–3.85%
Capital account		2.52%	1.80%	0.98%

ANALYSIS OF THE RESULTS

The overall BoP account balances under all the four scenarios, are in deficit even after considering a reasonable growth in exports of non-energy goods and receipts from invisibles. In the first two scenarios, the contribution of invisibles to the trade balance is reduced significantly from its 2011/12 level, because of the fixed level of invisibles' receipts along with larger imports of energy goods. For instance, in Scenario 3, the contribution of invisibles to the trade balance decreases from 58.8% (2011/12) to 21% (2030/31), but is higher than the value projected in Scenarios 1 and 2, as growth in receipts from invisibles has been considered in Scenario 3. In Scenario 4, the CAD is improved as invisibles follow a high growth path.

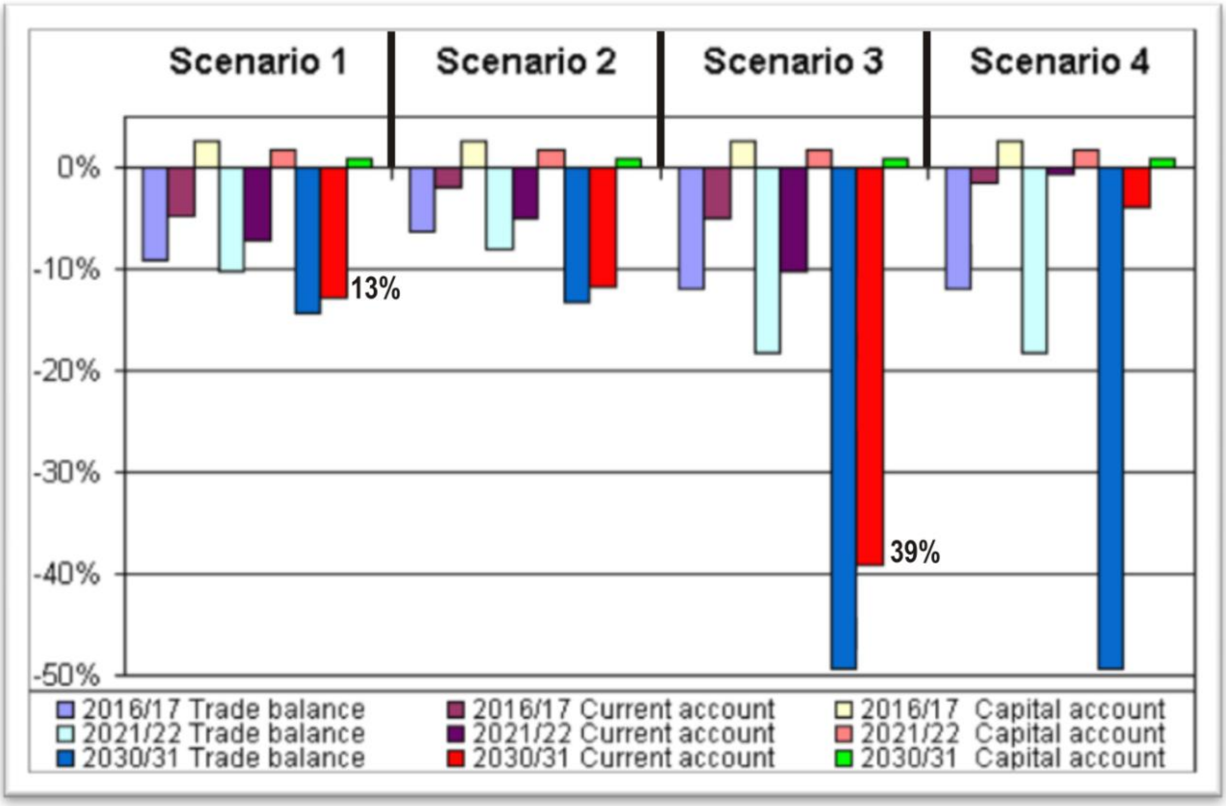

Fig 4.2: Four Scenarios of India's future Balance of Payments

The contribution of capital account is assumed to be the same and positive for all the scenarios. The net capital outflow may be more in case of a volatile and uncertain world market. If the deficit in capital account is more than the surplus balance in current account, the overall BoP will be a deficit. If the deficit in energy as well as non-energy trade increases, the current account and overall BoP may be in a deficit. In that case, the magnitude of overall BoP will depend on the relative growth of invisibles and net inflows in the capital account.

A recent RBI working paper has estimated the sustainable level of CAD as 2.4%–2.8% of GDP, assuming that GDP grows at 6%–8%, inflation is around 5%, and interest rate and capital inflow follow their trends. Just after reforms in the 1990s, the sustainable level of CAD was assumed to be around 1.6% of GDP, which has changed substantially with the changing world market situations. Under the first three scenarios (Fig 4.2), the CAD is sustainable only up to 2016/17, and increases enormously thereafter. In Scenario 1, which shows the effect of increasing energy trade balances, keeping all other parameters unchanged, the CAD will reach an unsustainable figure of 13% of GDP in 2030/31. In Scenario 3, due to the high trade deficit along with slower growth in the receipts from invisibles, CAD will reach 39% of GDP, which is not only unsustainable but unmanageable, also on the macro-economic front. Only in Scenario 4, which shows high trade deficit, the CAD is at a sustainable level because of the high growth in receipts from invisibles and because the invisibles finance 92% of trade deficit. But in the current world economic condition, the assumption of continuous and high growth rate of invisibles is questionable.

The significant and high import rate of energy goods may weaken India's overall BoP situation in the near future. The situation may not improve if India does not gain considerably from trade in non-energy goods, receipts from invisibles, or capital account balance. The continuing deficit in BoP will surely affect (or reduce) India's foreign exchange reserves if there is no considerable gain through valuation changes. This may result in insufficient funds for imports if India does not reduce its dependency on energy goods import. Therefore, a path of growth that is not dependent on fossil fuels will help to sustain the optimistic macro-economic conditions for India.

WHY COAL IMPORTS WILL HAVE TO BE RESTRICTED

It is difficult to curb oil imports because the number of vehicles on the road continues to increase, with production platforms for vehicles having been established in the country. Further, a growing economy also entails increase in transportation, another factor leading to increased oil imports. These rising imports are relatively inflexible with respect to short-term policies; reduction in imports could be brought about by demand suppression through increased petroleum fuel prices (other avenues having failed), but this is a matter of great public sensitivity and all governments tend to shy away from it due to populist pressures.

In the case of LNG imports, since gas-based power plants are already running at sub-optimal capacity utilization factors (CUFs) over the last few years, the option of further reducing gas imports is restricted. Since gas is also the feedstock for fertilizers widely supplied to farmers across the country, the prospects of reducing fertilizer throughput is also ruled out due to similar populist pressures.

Therefore, we return full circle to the need to restrict coal imports (as well as gold and silver imports), to prevent the fuel import bill from reaching levels that are unsustainable for the economy. Restrictions on coal imports need not affect economic growth in India because viable renewable alternatives are now available. They can be developed and scaled up in the next decade or so to alleviate the coal shortage and also to solve the macro-economic problems.

* * *

5. OTHER POTENTIAL RISKS AND CONSTRAINTS FOR COAL ELECTRICITY BEYOND 2022

The major emergent constraints for the future of coal mining and thermal generation in India are summarized below. These constraints may operate at varying spatial and temporal levels; they may start kicking in at different points of time, with varying intensities. Nevertheless, as constraints, they will exhibit simultaneity.

The biggest future constraint will be that of increasing balance of payments problems arising from continuing growth of fossil fuel imports within which coal imports will occupy an increasing share. Macro-economic risks will arise from continuing current account deficits, trade deficits, and capital account deficits, and there will be increasing macro-economic unsustainability in an uncertain global economic environment. This has been discussed in detail in Section 4. Other related constraints are in the form of technological lock-in, rising non-performing assets (NPAs) in the power sector, energy security risks and national security risks, all contributing to reduced manoeuverability of the economy in conditions of rising instability and uncertainty. The multifarious constraints have been classified under four major heads:

- Risks and constraints of coal availability.
- Techno-economic constraints of coal-based generation.
- Constraints arising from externalities and climate change.
- Policy constraints.

A) RISKS AND CONSTRAINTS OF COAL AVAILABILITY

- **Constraints on Coal Reserves:** A conservative assessment shows the peaking of domestic coal production probably after 2030. However, this peaking could occur much earlier due to many other constraints. One important possibility is the emergence of coal-to-liquid (CTL) production in the country. Best estimates suggest that at an international oil price above US$ 54 per barrel, CTL will become viable. With the combined effects of peaking of oil and macro-economic stress due to BoP caused by increasing oil imports, the CTL route will start to appear more attractive. Four major coalfields with high quality coal reserves have been earmarked for future CTL development. If the country adopts the CTL route, the peaking of domestic coal will be accelerated.

  Another important possibility is the rapid emergence of Underground Coal Gasification (UCG) for power generation. Latest news reports indicate that about 33,000 sq.km (approx 1% of India's land area) are to be allotted for UCG. The huge reserves of coal to be used up in the process will further accelerate the domestic peaking of coal. The estimated peaking beyond 2030 has not factored in both these and many other possibilities. If these were to emerge, as they most probably will, the peaking date of domestic coal will be significantly advanced.

- **Technological Constraints on Raising Coal Output from Underground Mines:** Coal from underground mines is already significantly more expensive than coal from opencast mines. The technological requirements and higher cost may impede large scale use of this type of coal.
- **Constraints on Accelerating Growth of Coal Production:** The physical process of starting new mines and removing large quantities of coal from deep strata require increasing capital investments, sophisticated machinery, large scales of operation and large transportation infrastructure; none of these physical requirements can be met overnight.
- **Safety Constraints on Coal Mining:** These are predominant in underground mines due to land subsidence, dangers to townships, human habitations and infrastructure, besides dangers of mine flooding, dangers due to blasting, mine fires, etc.
- **Quality Constraints:** Indian coal generally has a low calorific value with high ash content, thus increasingly requiring washing with its attendant environmental consequences; it also implies that to deliver the same input heat value to thermal plants will require larger quantities of coal due to quality deterioration.
- **Bottlenecks in Coal Transportation:** The availability of wagons, new tracks, enhanced port capacities, heavy duty roads etc, are already proving to be constraints on the transportation of coal. With the envisaged increase in coal output required, these constraints will grow. For many years, thermal plants have operated with a coal inventory of one week, in many cases even less. In this situation, the slightest disruption in coal transportation – due to storms, floods, accidents, political agitations, etc. – result in immediate disruption of coal supply to power stations, resulting in a crisis for the grid.
- **Constraints on Foreign Acquisition of Coal Assets:** The requirement of long-term fuel supply stability from foreign assets increasingly involves government-to-government negotiations, establishment of consortia of companies to handle mining, transportation by rail and sea, development of infrastructure in foreign countries, trans-shipment arrangement, etc., before the coal can be delivered to power stations in India; all these steps have to be successfully cleared to ensure long-term stability of supply and prices. They are not always easy to overcome.
- **Constraints Imposed by Policy Changes in Other Countries:** Long-term assurance of policy stability by foreign governments almost becomes a prerequisite for acquisition of foreign assets. In an uncertain environment, it is difficult for foreign governments to provide such assurances.
- **Constraints Posed by International Peaking of Coal:** If worldwide peaking of coal occurs, the prospect of stable coal prices in an international coal market starts receding, with spot purchases becoming increasingly difficult in a constrained market.

B) TECHNO-ECONOMIC CONSTRAINTS OF COAL-BASED GENERATION

All the constraints arising from the techno-economics of coal are reflected in the techno-economics of coal-based power, since the price of coal is the single largest uncontrolled variable in thermal power pricing. Some of these constraints are:

- **Cost Constraints:** If domestic coal shortage or deteriorating coal quality forces blending with higher calorific value imported coal which is more expensive, the cost of delivered power will increase, thereby reducing the profit margin in generation.
- **Cost-sustainability Constraints:** Thermal power prices have high increasing sensitivity to small escalation of coal prices, if the changes in coal costs are not allowed as pass-through. For a fixed long-term power tariff, the higher the input cost of coal, the lower the profit from sale of power, in turn affecting debt repayment and returns on equity.
- **Technology Constraints:** High efficiency advanced combustion technologies are expected to progressively become cleaner, but there are added costs in terms of pollution control equipment, increased auxiliary consumption by the pollution control equipment and so on. If these are not allowed to be explicitly factored in during tariff determination, they have to be carried by the project, thereby increasing the cost of delivered power.
- **Subsidy Constraints:** While coal-based power generation receives a range of direct and indirect subsidies over the project lifetime from both central and state governments, this imposes a rising burden on the governments concerned which may force them to discontinue subsidies.
- **Constraints Arising from Internalization of Externalities:** Currently, the tariff determination methodology used for tariff fixing does not take cognizance of external damage costs due to power generation or coal mining. This makes thermal power appear to be cheaper, since only accounting costs are recognized. However, as the damage due to externalities mounts, it is likely that there will be growing public pressure to internalize the damage costs, resulting in increasing the cost of power. The range of externality damages are dealt with below.

C) CONSTRAINTS ARISING FROM EXTERNALITIES AND CLIMATE CHANGE

These may be viewed as a continuum of externality costs, consisting of local and global externality damage costs due to climate change. The constraints due to **local externality damage** costs imposed by coal mining and thermal generation include:

- **Constraints due to Damage to Land from both Coal Mining and Thermal Generation:** These comprise land destruction, mountain-top removal, land subsidence, underground fires, overburden and ash dumping, and damage to land and agriculture. Not only are further land-use changes considered undesirable, but agricultural productivity is anticipated to be negatively impacted, thereby increasing the importance of water for irrigation and preventing problems of food security.

- **Constraints due to Damage to Water Resources and Water Availability:** These comprise over-extraction of water; water pollution from washeries, ash dykes and thermal plant operations; acid mine drainage; and combined impacts on entire river basins. These may eventually pose a constraint to water availability for power generation particularly in drought years. In Maharashtra, Parli and Chandrapur thermal power stations had to face closure due to water shortage. Water constraints will also increase due to the impact of climate change on the hydrological cycle—one of the most serious projected impacts of global warming.

  Since most of the coalfields and reserves lie in Central and Eastern India, in areas which constitute the catchments of many major rivers – the Sone, the Damodar, the Subarnarekha, the Mahanadi, the Godavari, the Brahmani, the Baitarni, the Koel, and the Karo and their tributaries – the impacts of combined coal mining and power generation will be transmitted over a considerable part of the country. Basins of major rivers may be irreversibly damaged due to a combination of catchment deforestation, erosion and siltation, over-extraction of water, multiple sources of water pollution at basin levels along with the combined impacts on agriculture, drinking water supply, human health effects, impacts on aquatic communities and impacts on distant coastal areas where major rivers merge with the sea. These large-scale impacts will occur even as global warming starts triggering major changes in hydrological cycles. It can be anticipated that water constraints for power generation will become significantly more stringent with the passage of time; the process has already started.

- **Constraints arising from Damage to Biotic Resources:** Attempts are currently on to declassify many forest areas declared as 'no-go' areas for coal mining. This will damage forest cover, wildlife, biodiversity, wildlife corridors and habitats, besides causing pollution. The earlier "go–no go" classification of forest areas has now been renominated as "inviolate" forest areas with "pristine" forests. While the earlier "go–no go" guidelines have been declared as having no legal sanctity, through high-level government intervention, the policy on "inviolate" forest areas will be framed according to new criteria consisting of five short-term and eight long-term parameters. The draft criteria include forest cover, forest type, biological richness and wildlife value, hydrological, and socio-economic benefits. The criteria include catchment areas for rivers, wetlands and storage reservoirs for irrigation, water supply and power projects. At stake are an estimated 180,000 hectares (ha) of forest for mining. While the earlier "no-go" guidelines had declared 47% of mining areas (about 320,000 ha) as no-go areas, in effect permitting mining in 53% of the areas, the Coal Ministry now wants 90% as go-areas, thereby putting at risk about 290,000 ha of forests. The forest and biodiversity constraints can be anticipated to grow in the future, coupled with both forest rights provisions and changes in land use classification becoming more stringent due to litigation in Indian courts and international climate change considerations.

- **Constraints arising from Atmospheric and Air Pollution Damage:** These are mainly on account of release of sulphur dioxide particles, nitrogen oxides, heavy metals and acid rain and a consequent range of health damaging consequences, including pulmonary and vascular diseases; heavy metal toxicity; skin, eye and gastric effects; health risks due to release of radionuclides from combustion products; and rising health damage costs to surrounding communities.
- **Constraints arising from Damage to Vulnerable Communities:** These include displacement and rehabilitation costs, loss of livelihoods amongst forest-based, marine communities and marginal agriculturists, exploitation of women and child labourers from such communities, as well as denial of rights to affected communities. This may eventually lead to large-scale opposition to land acquisition, public protests, and other forms of opposition.

The constraints due to **global externality damage** costs imposed by coal mining and thermal generation include:

- **Constraints arising from Climate Negotiations:** Since climate change is recognized as a **global externality**, the impacts arising from the resultant global warming have to be superimposed upon the above local externalities. Such anticipated impacts arising from the global level include the need to reduce emissions over time, the voluntary or other commitments made during international negotiations on climate change, as well as constraints arising from monitoring and verification procedures, both national and international.

D) POLICY CONSTRAINTS

- A planned transition to renewable sources of power over the next few decades is imperative. When grid penetration of infirm RE sources like wind and solar increase beyond 20%, conventional sources of power generation will have to be utilized for grid balancing. Since storage technologies are not likely to be commercialized on a large scale for 10 to 15 years, we may be required to use coal as a bridging fuel. So conservation of coal to facilitate the transition to a green power system may become essential. Beyond 2022, it would be prudent to think of such a policy shift in coal resource allocation.
- The need to balance policies across the various energy and non-energy sectors (including policies related to coal, mining, electricity, environment, forests, water, land, biodiversity, etc).
- Need to balance policies between central and state powers related to many of the above sectors, since states will choose to enhance their revenues as well as their

powers over resources; states will also be responsible for results to be achieved through policy implementation, hence will seek enhanced rights.

- Need to constrain policies with respect to existing regulatory, judicial and constitutional provisions and framework, especially with respect to the protection of rights.
- Constraints arising from social opposition to policies related to land, water, forests, environment, and rights of vulnerable communities.
- Constraints arising from macro-economic governance legislation such as the Fiscal Responsibility and Budget Management (FRBM) Act, 2003, for containing fiscal deficits.

It may be emphasized that almost none of these constraints apply to RE-based power generation over the long run. This indicates that the increasing constraints of a coal-based generation pathway make it a high risk choice as compared to an RE-based pathway which constitutes lower risk and a more sustainable choice.

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6. COAL ELECTRICITY NOW COSTLIER
– RENEWABLES RACING TOWARDS GRID PARITY –

The traditional belief that coal-based electricity is cheap is not valid anymore. The prices of renewable power have fallen steeply in the recent past. World over, environmental externalities of fossil fuels are being quantified. Studies in India have also shown direct and hidden subsidies being enjoyed by conventional power generation. When the cost of externalities and subsidies are added, coal is not cheap anymore. Added to that is the burden of high cost of imported coal and the increasing cost of domestic coal. In some states, the cost of electricity from wind power is already less than electricity from new coal-based projects.

COST OF GENERATION AND TARIFF BASED ON BLENDED COALS

Table 6.1: Basic Assumptions for Tariff Calculation for Coal-based Projects

Sr. No.	Parameter	Value
1	Capacity utilization factor	80%
2	Auxiliary consumption	10%
3	Capital cost of power project	₹507 lakh
4	Salvage value	10% of capital cost
5	Debt fraction	70%
6	Interest rate on term loan	13.5%
7	Depreciation for first 12 years	5.28%
8	Depreciation for next 13 years	2.05%
9	Discount rate	11.08%
10	O&M cost	₹14.59 lakh/MW
11	O&M cost escalation	5% per annum
12	Return on equity	15.5%
13	Interest on working capital	12%
14	Station heat rate	2425 kcal/kWh
15	Calorific value of fuel (imported)	5500 kcal/kg
16	Calorific value of fuel (domestic)	4000 kcal/kg
17	Fuel cost (imported)	₹6000/tonne
18	Fuel cost (domestic)	₹2200/tonne
19	Escalation in fuel cost	5%

The study attempted to work out the real cost of generation from coal-based thermal power projects. The relevant assumptions as described above are given in Table 6.1.

Several scenarios were developed on the basis of the extent of use of imported coal. The basic assumptions are true for all the scenarios. The only variable is the share of imported coal in the total coal requirement or the proportion of the blend. As the imported coal usage changes, the resultant tariff changes accordingly (Table 6.2).

Table 6.2: Fixed and Variable Tariff for Coal-based Power Projects (Based on Blend of Imported Coal)

	Tariff		Fixed		Variable		
Proportion of imported coal in the blend (%)	(₹/kWh)	(¢/kWh)*	(₹/kWh)	(¢/kWh)*	(₹/kWh)	(¢/kWh)*	Variable as % of total
0	3.78	6.87	1.58	2.87	2.20	4.00	58.20
10	4.08	7.42	1.60	2.91	2.48	4.51	60.78
20	4.35	7.91	1.60	2.91	2.75	5.00	63.22
30	4.61	8.38	1.61	2.93	3.00	5.45	65.08
40	4.86	8.84	1.63	2.96	3.23	5.88	66.46
50	5.08	9.24	1.63	2.96	3.45	6.28	67.91
60	5.29	9.62	1.64	2.98	3.65	6.64	69.00
70	5.50	10.00	1.65	3.00	3.85	7.00	70.00
80	5.68	10.33	1.66	3.02	4.03	7.31	70.95
90	5.86	10.65	1.66	3.02	4.20	7.63	71.67

(* 1US$ = ₹55)

As can be seen from Table 6.2, the electricity tariff for coal thermal power projects varies with the extent of blend. The tariff for a plant that uses only domestic coal will be ₹3.78/kWh (6.87¢/kWh). The tariff will increase to ₹5.86/kWh (10.65¢/kWh) when imported coal accounts for 90% of the total coal requirement. The fixed cost does not change much in all the cases; it is in the range of ₹1.58/kWh to ₹1.66/kWh, because the assumptions related to fixed-cost components do not change. The major variation is in the proportion of imported coal and therefore the impact is reflected in the variable cost component. This component increases by ₹2/kWh if imported coal accounts for 90% of the total from no imported coal at all. If imported coal is 90%, the variable cost component will be ₹4.20/kWh and the total tariff will be ₹5.86/kWh. The contribution of variable cost i.e. fuel cost in total cost, increases from 58.2% (no imported coal) to 71.67% (90% imported coal). Therefore, if a coal thermal power plant uses 90% imported coal, three-fourth of the total tariff is the fuel cost.

The tariff is increased substantially if there is even 1% point increment in annual escalation rate of fuel cost. If fuel cost escalation is considered as 6% (instead of 5%), then in the 10% blend with imported coal, the fuel cost will increase by ₹0.24/kWh i.e. from ₹2.48 to ₹2.72. Similarly, if the proportion of imported coal is 90%, the increment in tariff is around ₹0.40/kWh. Similarly, if the increment in annual fuel cost escalation is considered as 2% point (i.e. 7% annual escalation in fuel cost instead of 5%), the impact on tariff will be ₹0.51/kWh (10% blend with imported coal) to ₹0.85/kWh (90% blend with imported coal). Therefore a small variation in fuel cost escalation factor has significant impact on tariff.

"At current prices of coal, the tariff for new coal power from domestic coal will be ₹3.78/kWh (6.87¢/kWh). If 90% imported coal is blended, the tariff will increase to ₹5.86/kWh (10.65¢/kWh). Even pool pricing will significantly increase the cost of coal-based electricity."

The base cost of imported coal is likely to be increased in the near future due to various reasons. A reasonable, stable fuel cost annual escalation may be valid if the developer has a long-term contract for coal supply. If the imported coal has to be purchased at the market rate every year, the annual fuel cost escalation factor may vary considerably.

Similarly, in case of domestic coal, if the developer does not have long-term linkages for coal supply and has to purchase from the open market (through auction), the fuel cost of domestic coal will be high. The present spot prices of domestic thermal coal at the National Commodity Exchange (NCDEX) are ₹3,360–₹4,010 per tonne. Also, the proposed pooling price mechanism may have an impact on the base cost of coal. The electricity tariff may increase by 7–8 paisa/unit due to the introduction of price pooling mechanism. All these possible situations may ultimately lead to higher tariff of electricity generated from coal-based power projects. An additional risk factor in the case of imported coal arises from exchange rate variations of the Indian rupee with respect to hard currencies.

The other costs associated with the fuel cost of coal-based power generation relate to hidden subsidies and environmental externality costs, and are discussed in the subsequent sections.

HIDDEN SUBSIDIES

There are few studies with reference to India which portray subsidies to the energy sector. Such studies were surveyed as part of our research. However, most of the studies centred on laying down subsidies provided to energy sectors in different countries of the world, including the electricity sector. Despite the use of widely varied methodologies to quantify subsidies to the energy sector, almost all previous reports have unequivocally shown high quantum of subsidies disbursed to the conventional energy sector. However, the methodologies adopted in the research process have been 'top-down' approaches, i.e. moving from the general to the specific, which do not yield technology-specific estimates. In contrast, a 'bottom-up' approach of estimation moves from the specific to the general. This is done first by quantifying the supportive measures provided to the specific generation projects in the conventional electricity generation sector (based on coal, gas, or hydro generation)

"An earlier research study by WISE has found that coal-based electricity already enjoys a hidden subsidy of 68 paise/kWh (1.45¢/kWh). This does not include subsidies given for transportation of coal."

followed by addition of their cumulative effects on the cost of electricity generated from the specific project(s) and in the end, generalizing across generation projects that use the same conversion technology and resource (coal or gas or hydro).

A study by the World Institute of Sustainable Energy (WISE), Pune, has tried to trace the benefits transferred to conventional generation projects in India by means of subsidies by identifying the specifics. The study by WISE has computed the monetized value of the measures of support accorded to each project over its lifetime. For this purpose, the report focused on 19 projects (1993/2003) spread across three different technologies – large hydro, coal-based thermal, and gas-based thermal – representing central public sector utilities, state public sector utilities, and private sector utilities. The implicit subsidies have been given by central and state governments through different policies. Among the incentives provided to the power projects, the important ones are exemption from customs duty or additional duty, tax holidays, depreciation, letters of credit, taking the tax on rate of interest (ROE) as a cost, performance subsidy, considering deemed generation, covering the foreign exchange risk in term loan at the central level and stamp duty exemption, exemption from sales tax on plant and machinery and from electricity duty, waiver of tax on sale of electricity, concession in royalty or fuel charges, counter guarantees, under pricing of water, lower costs or free of cost access to grid connection, subsidies on infrastructure, and low-interest loans at the state level. However, all benefits are not offered to each project, and the benefits sometimes vary across localities and regions.

The report arrived at the impacts of several incentives in three distinct steps:

(i) Calculating the cost of generation of individual projects without internalizing the benefits using 0% (public) and 10% (private) discount rates.
(ii) Calculation of central and state level incentives provided to the projects and then internalizing these costs as an add-up to the cost of generation of the projects using 0% (public) and 10% (private) discount rates.
(iii) Finding the difference as the impact of subsidies or incentives.

As a representative example, the cost of generation of the Kota thermal power station in Rajasthan at a 10% discount rate was estimated at 5.56 ¢/kWh (₹2.63/kWh), escalated up to 6.55 ¢/kWh (₹3.08/kWh) after internalization of monetized incentives, and thereby yielding an impact worth 0.96 ¢/kWh (₹ 0.45/kWh) for the project. Similarly, the benefits were estimated for all 19 power projects in the sample. The results for all coal-fired thermal power stations are given in Table 6.3.

Based on studies performed for the nine coal-based thermal power projects (Table 6.3), the report arrived at a weighted average impact of 1.23 ¢/kWh at 0% discount rate (₹0.58/kWh) and 1.45 ¢/kWh at 10% discount rate (₹0.68/kWh), considering incentives provided to the coal-based thermal power sector in the country.

On the basis of 68 paise/kWh of hidden subsidy and the current installed capacity of coal-based power plants, total hidden subsidy estimated for coal-based electricity generation in India would be around ₹561 billion (US$10 billion) per annum. Moreover, the subsidy given to railways for transportation of coal is not included in Table 6.3.

Table 6.3: Hidden Subsidies of Select Coal-based Thermal Projects in India

		Levelized Cost pf Generation without Internalization in ¢/kWh (₹/kWh)		Levelized Cost of Generation with internalization in ¢/kWh (₹kWh)		Subsidy in ¢/kWh (₹/kWh)	
Project	Capacity (MW)	0% (Public)	10% (Private)	0% (Public)	10% (Private)	0% (Public)	10% (Private)
Neyveli Lignite Thermal Power Station-II Expansion, Tamil Nadu	500	6.31 (2.97)	6.78 (3.19)	7.42 (3.49)	8.06 (3.79)	1.11 (0.52)	1.28 (0.60)
Mejia Thermal Power Station, West Bengal	210	3.95 (1.86)	4.59 (2.16)	5.87 (2.76)	6.57 (3.09)	1.91 (0.90)	1.2 (0.94)
Simhadri Stage-I, Andhra Pradesh	1000	3.33 (1.55)	3.66 (1.72)	4.51 (2.12)	5.10 (2.40)	1.21 (0.57)	1.42 (0.67)
Talcher Super Thermal Power Project Stage-II, Odisha	2000	3.04 (1.43)	3.51 (1.65)	4.32 (2.05)	5.06 (2.38)	1.32 (0.62)	1.55 (0.73)
Akrimota Lignite-based Thermal Power Station Unit 1&2, Gujarat	250	4.34 (2.04)	5.12 (2.44)	5.7 (2.68)	6.74 (3.17)	1.36 (0.64)	1.55 (0.73)
Kota Thermal Power Station Stage IV, Rajasthan	195	5.93 (2.79)	5.60 (2.63)	6.78 (3.19)	6.55 (3.08)	0.85 (0.40)	0.96 (0.45)
Neyveli Zero Thermal Power Station, Tamil Nadu	250	12.14 (5.71)	10.61 (4.99)	13.22 (6.22)	11.95 (5.62)	1.08 (0.51)	1.32 (0.62)
Jojobera Thermal Power Project, Jharkhand	240	4.7 (2.21)	5.42 (2.55)	5.7 (2.68)	6.63 (3.12)	0.10 (0.47)	1.23 (0.58)
Surat Lignite Unit III and IV, Gujarat	250	7.31 (3.44)	7.08 (3.33)	8.23 (3.87)	8.14 (3.83)	0.01 (0.43)	1.06 (0.50)

EXTERNALITIES OF COAL QUANTIFIED

There are significant variations in the estimation of externality costs of coal mining and coal-based power generation. Various researchers have conducted studies from 1995 up to 2009, both in Europe and the US. The difference in externality cost estimation arises from differences in assumptions about types of impact and unit damage costs, characteristics of pollutants, spatial boundaries, impact and monetization models, population, discounting rate used, uncertainty factor in estimation, etc. Even though there is a broad acceptance that there are serious health and environmental consequences of coal mining and thermal power generation, disputes arise in monetizing the externality costs.

The health impacts due to coal mining and coal combustion deserve special attention as these are quantitatively the largest of the 'externalized costs' of these activities. The health impacts include cancers (from the heavy metals in the flue gases viz arsenic, cadmium, chromium, nickel and dioxins) and increased mortality and morbidity from the other primary pollutants (PM_{10}, SO_2, NO_2, and volatile organic compounds or VOCs). For most air pollutants, atmospheric dispersion is significant over hundreds to thousands of kilometres. The most significant inter-disciplinary methodological work has undoubtedly been done in the Extern-E Project of the European Commission based on which the health damage costs and other externality costs due to the various sources of power generation were computed for the countries of Europe. More recently, a study conducted by Epstein et al. have computated the externality costs of coal per kWh of electricity generated in the United States – this works out to 9.42 ¢/kWh to 26.89 ¢/kWh of electricity with a best estimate of 17.84 ¢/kWh (₹8.92 per kWh, assuming 1 US$= ₹50). The authors conclude… "the damages, conservatively estimated, doubles to triples the prices of electricity from coal per kWh generated, making wind, solar and other non-fossil-fuel power generation economically competitive." Amongst the team of eleven authors of the study, at least four are from reputed University Departments of Public Health.

HOW CHEAP IS COAL?

The base electricity cost (tariff) for coal thermal power projects in India varies between ₹3.78/kWh (6.87 ¢/kWh) to ₹5.86/kWh (10.65 ¢/kWh) with the extent of blending of imported coal. The impact of hidden subsidies provided to the coal-based thermal power sector in India is ₹0.58/kWh at 0% discount rate (1.23 ¢/kWh) and ₹0.68/kWh at 10% discount rate (1.45 ¢/kWh). The best cost of externalities associated with coal-based electricity generation is equivalent to ₹8.92/kWh (17.84 ¢/kWh), ranging from ₹4.43/kWh (9.36 ¢/kWh) to ₹12.65/kWh (26.89 ¢/kWh).

With the base cost (tariff) of coal, hidden subsidy at 0% discount rate, and best estimate of externality costs, the true cost of electricity is estimated at around ₹12.75/kWh (25.94 ¢/kWh) by considering 100% domestic coal use. If we consider 90% imported coal use, then the true cost would be around ₹14.83/kWh (29.72 ¢/kWh).

This estimation of true cost of coal-based electricity can change the perception about 'cheap' coal and can be comparable with the 'high cost' alternatives. In the changing conditions of growing resource constraints and rising global fuel prices, the base cost of coal-based electricity may be more than the cost of alternatives. Therefore, any decision about fuel choice must be taken on the basis of 'true' cost only. On the basis of the above discussion, renewables are placed in a better position than coal-based electricity generation.

WIND POWER CHEAPER THAN COAL ELECTRICITY

Table 6.4 shows the wind power tariff in different states in India and the tariff for new coal-based projects using domestic coal and blends of domestic and imported coal. In the three states of Kerala, Karnataka, and Tamil Nadu, the wind power tariff is lower than the tariff for new domestic coal-based thermal electricity (₹3.78). Electricity produced from a blend of domestic and imported coal will cost anywhere from ₹4.08 to ₹5.68, depending on the ratio of blending (from 90:10 to 20:80). When the externality costs and hidden subsidies are added to this, all forms of coal-based electricity will be much more expensive than renewable power, including wind and solar. The lowest rates of solar PV-based electricity quoted in the recent bidding in Tamil Nadu is as low as ₹5.97/kWh, which is cheaper than electricity produced from purely imported coal.

Table 6.4: Wind Vis-à-vis Coal Tariff in Major Wind Generating States

State	Average Wind Tariff (₹/kWh)	Scenarios	Blending Ratio	Average Tariff (₹/kWh)
Andhra Pradesh	4.70	Only domestic coal	100-00	3.78
Gujarat	4.30	* Domestic Imported (D:1)	90-10	4.08
Karnataka	**3.70**	**(D:1)**	**70-30**	**4.61**
Kerala	**3.64**	**(D:1)**	**60-40**	**4.86**
Madhya Pradesh	4.35	(D:1)	50-50	5.08
Maharashtra	3.78-5.67	(D:1)	30-70	5.50
Punjab	5.07	(D:1)	20-80	5.68
Rajasthan	4.46-4.69			
Tamil Nadu	**3.51**			

*1 Derived normative tariff for coal-based thermal plant as per Central Electricity Regulatory Commission-2009 Tariff Regulation.

2 Wind power tariff as per recent SERC tariff orders.

RENEWABLE ENERGY RACING TOWARDS GRID PARITY

Even as the risks and uncertainties around the coal-based path are growing, the future prospects for RE, both internationally as well as in India, is improving by leaps and bounds. The evidence for RE performance in India are clearly visible in the last two plan periods. While over 6,000 MW of RE capacity was added in the 10th plan period, over 12,000 MW was added in the course of the 11th plan period, an effective doubling even in the face of recessionary external pressures. Most of the capacity addition came from wind power, even as policies were being changed; solar growth has also started registering its presence with over 1,000 MW grid-connected solar power capacity installed. A quick overview of both wind power and solar power prospects, being potentially the largest future contributors to RE-based generation, is presented in the following paragraphs.

Wind power is now a mature industry in India, with major domestic and international manufacturers already operating under competitive conditions. In 2011/12, wind power alone added over 3,000 MW of generating capacity in a single year, and the performance is easily expected to touch 5,000 MW per year by 2015. Under appropriate conditions, the wind industry in India can quite easily scale up to 10,000 MW per year of capacity addition in the next few years. Moreover, the tariffs are in the range of ₹3.00 to ₹5.00 across the country, which puts them on a competitive basis with most conventional sources of electricity, except hydro power. Much of the policy and regulatory framework has already been evolved and put into place, and has provided the learning space for the development of RE policy. Any changes in cost of installation per MW now arise due to changes in prices of steel and cement, which are vital inputs for the industry, but beyond their control. In brief, with a huge potential of onshore and offshore wind awaiting development, the future growth of wind power need not be in doubt.

Solar power is beginning its journey in India. It has been a late start, despite the tremendous availability of insolation across the country. India has been decidedly late in mapping and establishing the potential from solar power across the country, mostly because solar power was considered expensive, with none of its other positive attributes being granted sufficient recognition (low environmental externalities, low social displacement, energy and national security implications, benefits to the macro-economy, potential for decentralized economic growth, zero emissions during operation, long-term and non-depletable resource, potential for employment growth including in agriculture). Nevertheless, solar power has made impressive gains internationally in terms of installed capacities, falling investment and delivered electricity costs, technology development, and so on.

"Solar power may reach grid parity sooner than expected – even as early as 2015. So all renewables are racing towards grid parity and have very negligible externalities."

The second round of competitive bidding under the Jawaharlal Nehru National Solar Mission (JNNSM) resulted in the discovery of the lowest bid at ₹7.49 per kWh. Subsequent bidding under solar initiatives by state governments have resulted in solar PV-based electricity prices falling to as low as ₹5.97/kWh, as in the case of the recent Tamil Nadu bidding process. Industry sources in India indicate a long-term trajectory towards ₹5/kWh, though Indian interest rates are amongst the highest in the world currently. Industry sources such as Solarbuzz which monitor global solar prices, show that global solar electricity prices from an industrial scale of 500 kW flat roof mounted solar systems have fallen from 16.27 ¢/kWh in March 2011 to 15.15 ¢/kWh in March 2012 (₹8.14 to ₹7.58/kWh). This shows that even for small rooftop projects, prices are falling.

In the case of PV modules, landed cost in Europe of Chinese and other emerging market manufacturers of c-Si modules had dropped to around US$1.05/W. Spot and factory gate prices for c-Si modules from European, Japanese, and other manufacturers had declined to between US$1.22 and US$1.4/W (Figure 6.1).

It may be noted that the current costs of solar electricity are based on the lowest efficiency, earliest developed technologies manufactured on relatively small scales, with low CUF. The future trajectory along competitive lines will consist of higher conversion efficiencies, high CUF (through tracking), lower manufacturing costs (through large-scale manufacturing), and improved performance and reliability through continuous development and service provision back-up. Any combination of these developments will result in lowering the delivered costs of solar electricity.

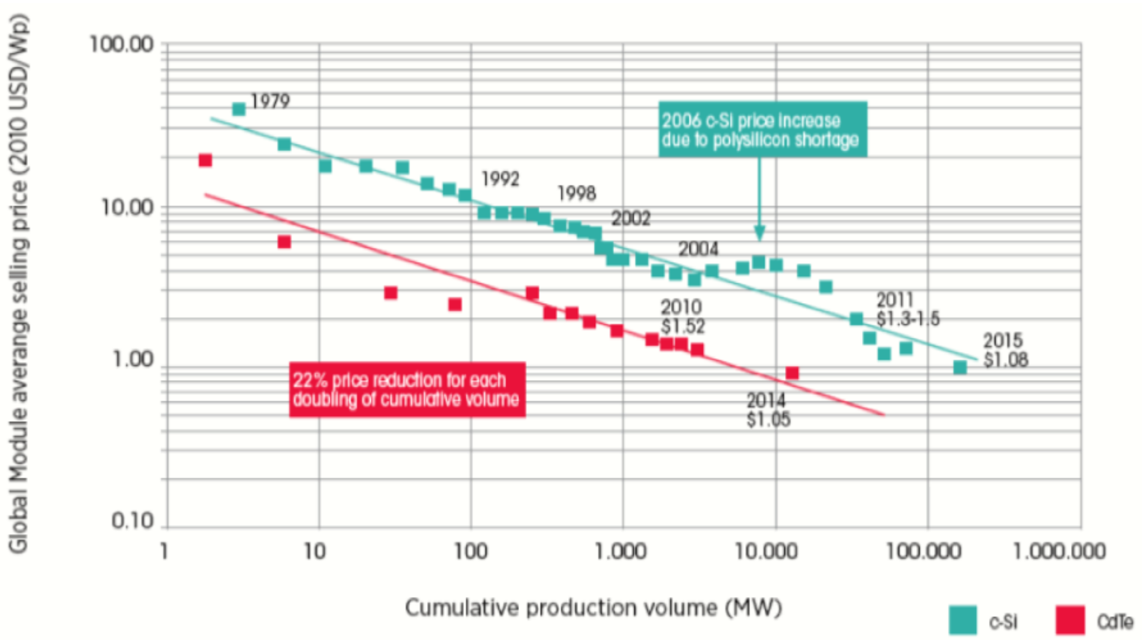

Figure 6.1: Global PV Module Price Learning Curve for C-Si Wafer-based and CdTe modules (1979 to 2015)

On the other hand, much of the policy and regulatory framework for solar power is already in place or can be put in place at an early date. Whereas the JNNSM had set a national target of 3,000 MW of installed solar capacity by 2017, the Government of Tamil Nadu in November 2012 has invited bids for 3,000 MW of solar power in the state, under a new state RE policy. Similarly, Gujarat has already crossed 600 MW of installed solar capacity; other southern and western states can be expected to follow suit. The pace of solar development is likely to significantly outpace current national targets. In the face of these developments, the national targets appear conservative.

Factored together, the prospects for RE contribution via the solar and wind sectors provide a challenging answer to the search for energy security and national security, coupled with near zero carbon emissions, very low environmental externalities, and a rapid response to climate threats. This is particularly so as both technologies are modular. With tens or hundreds of industrial units making different sub-systems and components and with competent systems integrators able to execute projects, there is no reason to doubt the rate at which these technologies can grow, provided they receive appropriate stimulus on time.

The future contributions from RE need not be confined to the wind and solar sectors alone. A tremendous amount of R&D is taking place around the world in futuristic technologies based on different RE sources such as geothermal, tidal and wave energy. Over a long-term horizon, some of these will at least reach techno-commercial maturity, so that a future based on green electricity is no longer as remote as it seemed even a decade ago. Even with the current mature technologies, there is ample potential for RE sources to provide at least 75% of India's electricity needs by 2050.

* * *

7. The Sustainable Alternative – 75% Green Power by 2050 –

Future energy demand projections are essential for ensuring energy security. The projections help in planning to meet the demand and assessing the risks to energy availability over the period. For ensuring future growth, preparation of a roadmap for energy requirements and energy resources to fulfill the growing demand for energy is crucial. There are various methodologies for projecting electricity demand as listed below.

- Econometric method
- Time series
- Time trend (CAGR)
- End use
- Partial end-use

However, here we have used **two different methodological approaches viz econometric method and partial end-use method** (which is a combination of time series and end-use methods). The time trend (CAGR) approach is not resorted to because of its tendency for over-projections.

The econometric method ascertains energy demand by considering the influence of independent variables such as GDP growth, population, employment, income, market prices, etc. In short, econometric models are estimated equations that relate electricity demand for external factors such as those listed above. The time series method to forecast the total demand for electricity/energy (not sector-wise) is based on the patterns and trends found in input data. In using the time series method, the researcher extrapolates statistical data to calculate loads based upon historical data for the load being forecast. In the end-use method, the sector-wise energy demand of each sector is projected by determining the energy intensity of each, and the overall demand is found by the summation of demand of all the sectors. **The partial end-use method** is the combination of end-use method and time series method to extrapolate available data (in this case available upto 2010/11) of individual sectors into the future using time series and then summing it up to arrive at the total.

The gross potential of different renewable sources of power is also assessed to see whether a transition to a green energy economy is possible from a resource potential perspective. It is found that there is no supply-side constraint in moving towards a renewable economy even by 2050. The results of both the approaches almost match and complement each other.

PART I: THE ECONOMETRIC METHOD

Within the econometric approach, two models, viz the *basic model* and the *reference model* have been used. The *basic model* has been used to derive the energy demand. This model assumes the demand for energy of each sector of the economy as a function of its income and the real energy price it faces. The partial income elasticity of demand and the partial price elasticity are assumed to remain constant over the period of projection. The *reference model* is used to derive energy intensity. This model provides us with the growth rate of energy intensity in the years passed for the entire economy as well as for each sector. This in turn provides the basis for comparing the model based growth rates.

The energy intensity growth derived using this model is given in Table 7.1 below. It is separately estimated for the periods of 1990/2004 and 2005/2009. It would be seen from the past energy consumption pattern that the Indian economy has been moving along a low-energy growth path and the energy intensity has shown a positive decline.

Table 7.1: Energy Intensity Growth via the Econometric Method

Sector	Growth Rate (1990/2004)	Growth Rate (2005/09)
Entire Economy	–3.3%	1.0%
Agriculture	1.9%	4.0%
Transport	–4.6%	0.6%
Residential	2.3%	–3.5%
Industry	–5.4%	1.0%
Other Services	–1.6%	–5.6%

Energy Demand Projections

The projections here are the result of a modelling exercise, which takes the year 2009/10 as the base year. The projections using the *basic model* are made assuming three growth scenarios and two price scenarios. The growth scenarios assumed are: 1) 8% GDP growth rate from 2010/2045, 2) GDP growing at 8% from 2010/2031 and at 7% from 2032/2045 and, 3) 7% GDP growth rate from 2010/2045.

The sector-wise GDP projections are made by calculating the elasticity of sector-wise GDP with respect to the overall GDP of the economy and then finding the corresponding growth rates of the sectoral GDP according to the various scenarios. The 'private final consumption expenditure' is used as an indicator of income for the residential sector. Table 7.2 gives the overall GDP elasticity of sector-wise GDP for the 5 sectors viz agriculture, transport, industry, other services and residential, based on the data for the period from 1990 to 2009.

Table 7.2: GDP Elasticity of Sector-wise GDP from 1990 to 2009

	Industry	Transport	Agriculture	Other services	Residential
Overall GDP Elasticity of Sector-wise GDP	1.06	1.15	0.424	Residual after accounting for industry, transport and agriculture.	0.846

The projections of final energy demand using *basic model* are given in Table 7.3 for three different GDP growth rates along with change in real price of energy index. The price scenarios are constructed assuming a real price growth rate of 0% in one case and 3% in the second case. Considering 8% of economic growth, the final energy demand in 2045/46 would be 18,57,847 kilo tonnes oil equivalent (ktoe) with constant real price, and 9,32,263 ktoe with real price change of 3%.

Table 7.3: Demand for Energy in 2045/46 for Three Different GDP Growth Rates (ktoe)				
		GDP Growth Rate		
Sector	Real Price of Energy Index Change	8% from 2010/2045	8% from 2010/2031 and at 7% from 2032/2045	7% from 2010/2045
Overall economy	0%	1658094	1513681	1311732
	3%	964018	907764	786654
Industry	0%	334093	316782	291373
	3%	176757	167598	154155
Transport	0%	1106257	958247	764635
	3%	380834	329881	263229
Agriculture	0%	102570	91690	76877
	3%	59746	53409	44780
Other services	0%	186587	172350	152041
	3%	same	same	same
Residential	0%	128340	121339	111101
	3%	same	same	same
Overall economy aggregated	0%	1857847	1660408	1396026
	3%	932263	844576	725306

[Note: Detailed calculations of final energy demand projections have been undertaken corresponding to each of the above growth rates. These have not been included for reasons of space.]

Table 7.4 and Table 7.5 give the energy intensity of overall economy using the *reference model* in the terminal year for the 8% growth in GDP scenario across the two price scenarios and the projections for 0% change in real energy price scenarios across the three growth scenarios.

Table 7.4: Energy Intensity for 8% GDP Growth Scenario		
Year	Real Price of Energy Index Change of 0%	Real Price of Energy Index Change of 3%
2009	0.065	0.065
2021	0.047	0.039
2031	0.038	0.026
2045	0.031	0.016

The results of the analysis of the past energy consumption pattern and its future projection point out that the Indian economy has already been moving along a low energy growth path. Its final energy intensity of GDP is projected to decline at the rate of 1.96% per annum over the time horizon 2009/10 to 2045/46 even when we consider the highest GDP growth of 8% per annum and no real energy price change scenario and take a sectoral approach to arrive at the economy-wide estimates by aggregation. The rate of decline of energy intensity can be enhanced to 3.74% per annum if the final energy prices in real terms rise at the rate of 3% per annum, inducing technical change for energy conservation. The energy intensity of GDP is in fact expected to decline for every sector for the baseline scenario, except for agriculture where the energy intensity is projected to grow with more intensive cultivation. These rates of decline of energy intensity are not however sensitive to the choice of GDP growth rate for any given scenario of real price changes.

Table 7.5: Energy Intensity for 0% Real Price of Energy Index Change

Year	GDP Growth Rate of 8% from 2010/2045	GDP Growth Rate of 8% from 2010/2031 and 7% from 2032/2045	GDP Growth Rate of 7% from 2010/2045
2009	0.065	0.065	0.065
2021	0.047	0.047	0.049
2031	0.038	0.038	0.040
2045	0.031	0.032	0.033

Projecting the Demand for Electricity

Projecting the demand for electricity in the total final energy consumption requires us to make certain assumptions regarding the share of electricity in final energy consumption for each sector. The assumptions for the share of electricity based on international standards for each sector are given in Table 7.6. The shares are generated using linear growth of share with the base year as 2009, except for transport. For the latter sector, the share has been assumed on the basis of assumption of penetration of electric motor vehicles in urban transport.

Table 7.6: Assumptions for Sector-wise Electricity Share in Final Energy Demand for 2010/2045 (Based on International Standards)

Share of Electricity in year	Industry	Transport	Agriculture	Other Services	Residential
2009	26.11%	2.08%	59.46%	27.16%	32.09%
2021	30.21%	2.95%	60%	35.44%	35.31%
2031	33.63%	4.00%	60%	42.34%	38.00%
2045	35.00%	6.00%	60%	52.00%	45.00%

The demand for electricity is estimated for the projection period using the electricity shares given in Table 7.6. The details of the electricity demand in the terminal year for each sector under different GDP and price scenarios are given in Table 7.7.

Table 7.7: Demand for Electricity in 2045/46 for different GDP and Price Scenarios (ktoe)				
		GDP Growth Rate		
Sector	Real Price of Energy Index Change	8% from 2010/2045	8% from 2010/2031 and at 7% from 2032/2045	7% from 2010/2045
Industry	0%	116933	110874	101981
	3%	61865	58659	53954
Transport	0%	66375	57495	45878
	3%	22850	19793	15794
Agriculture	0%	61542	55014	46126
	3%	35848	32045	26868
Other services	0%	97025	89622	79061
	3%	same	same	same
Residential	0%	57753	54603	49996
	3%	same	same	same
Overall economy aggregated	0%	399628	367607	323042
	3%	275340	254722	225673

[Note: Detailed calculations of final electricity demand projections have been undertaken corresponding to each of the above growth rates. These have not been included for reasons of space]

Fuel-wise Share to Meet Demand

Table 7.8: Assumptions for Auxiliary and Transmission & Distribution Losses and Efficiency Factors							
Year	Auxiliary and T&D Losses	Linear Rate of Increase in Conversion Efficiency of Coal	Conversion Efficiency of Coal	Linear Rate of Increase in Conversion Efficiency of Gas	Conversion Efficiency of Gas	Linear Rate of Increase in Conversion Efficiency of Furnace Oil	Conversion Efficiency of Furnace Oil
2009	28.33%	0.3077	29.2%	0.1154	42.5%	0.2308	33.0%
2021	20%		32.3%		43.9%		35.8%
2031	18%		35.0%		45.0%		38.0%
2045	15%		38.7%		46.6%		40.8%

Once we have estimated the demand for electricity in units of thousand tonnes of oil equivalent, we can project the demand for coal, gas and fuel oil (in natural units) required for electricity generation. The first step will be to estimate the gross electricity generation in units of electricity by accounting for the auxiliary use and transmission and distribution losses. Table 7.8 gives the normative values of such losses for our projections. As there exists substantial scope of efficiency improvement in India on the supply side as well, Table 7.8 provides the target norms of such losses or conversion efficiency over the planning horizon.

The gross electricity generation after incorporating the auxiliary and T&D losses is given in Table 7.9. In the terminal year, the gross electricity generation with constant real price would be in the range of 4,420 – 5,468 billion kWh at 8% growth rate. However the scale of generation requirement would obviously be affected by the choice of GDP growth rate. The estimates of the gross generation at 8% GDP growth rate range between 3,767 billion kWh and 5,468 billion kWh in 2045/46, rising from 907 billion kWh currently, depending on the extent of energy price rationalization by the upward revision of their real prices as faced by the different sectors.

Table 7.9: Gross Generation of Electricity (including Auxiliary and T&D Losses) (in Billion kWh)

		GDP Growth Rate		
Particulars		8% from 2010/2045	8% from 2010/2031 and at 7% from 2032/2045	7% from 2010/2045
Real price of energy index change of 0%	2009	907	907	907
	2021	1537	1537	1447
	2031	2578	2578	2294
	2045	5468	5030	4420
Real price of energy index change of 3%	2009	907	907	907
	2021	1356	1356	1277
	2031	2058	2058	1834
	2045	3767	3485	3088

Once we have the gross electricity demand estimated, the projections for the demand for coal, oil, natural gas and renewable energy are derived by making certain assumptions regarding shares of different fuel-based modes of generation as given in Table 7.10 and Table 7.11. Table 7.10 gives the scenario for the normative or baseline electricity generation from renewables as per the targets of NAPCC, and Table 7.11 gives the scenario for accelerated electricity generation from renewables sources.

Table 7.10: Share of Fuels in Electricity Generation: Baseline Growth in Electricity using Renewables

Year	Coal	Gas	Fuel Oil	Hydro Electricity	Nuclear	Renewables
2009	70%	11.5%	1.7%	13%	2.3%	1.5%
2021	60%	11.5%	1.7%	13%	2.3%	11.5%
2031	50%	11.5%	1.7%	13%	2.3%	21.5%
2045	29%	11.5%	1.7%	13%	2.3%	42.5%

Table 7.11: Share of Fuels in Electricity Generation: Accelerated Generation using Renewables						
Year	Coal	Gas	Fuel Oil	Hydro Electricity	Nuclear	Renewables
2009	70%	11.5%	1.7%	13%	2.3%	1.5%
2021	60%	11.5%	1.7%	13%	2.3%	11.5%
2031	45%	11.5%	1.7%	13%	2.3%	26.5%
2045	17%	11.5%	1.7%	13%	2.3%	54.5%

Table 7.12: Electricity Generation from Renewables for the Three GDP Growth Scenarios (in Billion kWh) (based on Baseline and Accelerated Growth of Renewables)					
			GDP Growth Rate		
Particulars			8% from 2010/2045	8% from 2010/2031 and 7% from 2032/2045	7% from 2010/2045
Real price of energy index change of 0%	Baseline growth	2009	13.61	13.61	13.61
		2021	176.76	176.76	166.41
		2031	554.27	554.27	493.21
		2045	2323.90	2137.75	1878.50
	Accelerated growth	2009	13.61	13.61	13.61
		2021	176.76	176.76	166.41
		2031	683.17	683.17	607.91
		2045	2980.06	2741.35	2408.90
Real price of energy index change of 3%	Baseline growth	2009	13.61	13.61	13.61
		2021	155.94	155.94	146.86
		2031	442.47	442.47	394.31
		2045	1600.98	1481.13	1312.40
	Accelerated growth	2009	13.61	13.61	13.61
		2021	155.94	155.94	146.86
		2031	545.37	545.37	486.01
		2045	2053.02	1899.33	1682.96

Table 7.11 indicates that by accelerating the development of renewables, it is possible to reach 54.5% of green electricity in the grid by 2045; at a rate of 2% per annum growth of renewable electricity for an additional five years, this means 64.5% green electricity by 2050. Since hydro should also be

considered as green electricity where emissions are concerned, the additional 13% from hydro will take the total green electricity in the grid to 77.5% by 2050.

Table 7.12 gives the demand for electricity generation from renewables for three growth scenarios along with two price scenarios and the baseline and accelerated development of generation of electricity from renewables. In the 8% growth scenario, with constant real prices, the generation from renewables would be 2,324 billion kWh in the case of baseline scenario and 2,980 billion kWh in the case of accelerated growth scenario in 2045. In terms of final energy prices rising at 3% per annum, generation from renewables would fall to 1,600 billion kWh in the baseline scenario and 2,053 billion kWh in the accelerated growth scenario in 2045.

PER CAPITA ELECTRICITY GENERATION

Tables 7.13 and 7.14 give the per capita electricity that will have to be generated from various fuel sources corresponding to the gross electricity generation given in Table 7.9.

Table 7.13: Per Capita Gross Generation of Electricity (kWh/capita) for 8% GDP Growth Scenario (0% Real Price Index vis-à-vis 3% Real Price Index)

Year	Real Price of Energy Index Change of 0%	Real Price of Energy Index Change of 3%
2009	775	775
2021	1097	968
2031	1681	1342
2045	3284	2262

Population projections based on - Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, World Population Prospects: The 2010 Revision, http://esa.un.org/unpd/wpp/index.htm

Table 7.14: Per Capita Gross Generation of Electricity (kWh/capita) for 0% Real Price of Energy Index Change (For the Three GDP Growth Scenarios)

Year	8% GDP Growth Rate from 2010-2045	8% GDP Growth Rate from 2010/2031 and 7% from 2032/2045	7% GDP Growth Rate from 2010/2045
2009	775	775	775
2021	1097	1097	1033
2031	1681	1681	1495
2045	3284	3021	2655

Population projections based on - Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, World Population Prospects: The 2010 Revision, http://esa.un.org/unpd/wpp/index.htm

If we consider the per capita gross electricity generation to be an index of the level of well-being of the people, its projected level would be 3,284 kWh per annum in 2045/46 as per the baseline scenario of 8% growth with no real energy price change. However, it is important to note that the per capita gross generation would fall to 2,262 kWh in the same terminal year for the same GDP growth rate but with 3% annual rise of real energy prices. Since growth is not sacrificed by such policy, such lowering of per capita gross generation need not represent any lowering of the level of well-being of the people, but would represent the price induced realization of potential energy savings and higher energy efficiency.

PART II: THE PARTIAL END-USE ANALYSIS METHOD

Electricity Demand Projection by Various Organisations

For projecting India's electricity demand, various estimates by CEA, the International Energy Agency (IEA), European Renewable Energy Council (EREC) and WISE were considered (Table 7.15)

Table 7.15: India's Electricity Demand as Projected by Various Organizations

Organization	Methodology	Year of Prediction	Timeframe (year)	Electricity Demand (BU)
Central Electricity Authority (CEA)	Partial end-use method	Draft 18th EPS (2011)	2021/22	1872–2243
International Energy Agency (IEA)	Compound Annual Growth Rate (CAGR)	IEA 2009 analysis	2050	3168–3583
European Renewable Energy Council (EREC)	End-use method	2010	2050	4458–5062
World Institute of Sustainable Energy (WISE)	1.Partial end-use method	2012	2050	5181
	2.Time series analysis		2050	3821
	3. CAGR method		2050	9644

From Table 7.15, it is clear that India's electricity demand, although projected by CEA at 1,800–2,200 BU by 2022, will increase slowly thereafter until 2050. Most of the analyses and projections show that by 2050, India's electricity demand will be in the range of 3,200–5,200 BU. Only in the CAGR method, the estimated demand is much higher, at more than 9,600 BU in 2050, because it is based on 9% GDP growth and 0.8 elasticity throughout, which is a very unlikely scenario. In the case of EREC's advanced revolution scenario, which projects the demand in the range of 4,458–5,062 BU, electricity demand for transportation is also included, assuming that transportation resorts to electric drives. Considering WISE's projection by the partial end-use method (5,181 BU) by 2050 and the transportation demand (approx.118 BU as estimated by WISE), the total demand works out to 5,299 BU by 2050. So it can be concluded that India's estimated electricity demand by 2050 will be in the range of 3,200–5,200 BU.

RE POTENTIAL NOT A CONSTRAINT

The total potential of new and renewable sources of energy as estimated by WISE (solar power) and other organizations through various studies are shown in Table 7.16. This is a conservative estimate and yet the total potential comes to 3,941 GW, which includes 150 GW large hydro potential (as estimated by the government). So it is evident that availability of renewable energy resources will not be a constraint in moving towards 100% renewable power in the next few decades.

Table 7.16: Total New and Renewable Energy Potential for India

RE Technology	Resource Estimation Parameter/s	Estimated Potential (MW)	Source
Onshore wind power	At 80 m height, 100% utilizable crop, plus wasteland with WPD >200 W/m^2	2,006,000	Lawrence Berkeley National Laboratory, USA
Offshore wind power	At 33% CUF, 100 m hub height with 3.6 MW machine rating	380,517	Harvard University, USA
Solar power	Solar PV: 5% utilizable wasteland in India	573,546	WISE
	CSP: 5% utilizable wasteland in India	477,955	WISE
	Rooftop solar PV	254,644	WISE
	Solar PV water pumping	37,372	WISE
Bioenergy	Biomass power	18,000	MNRE; IISc, Bengaluru
	Cogeneration (bagasse-based)	5,000	MNRE
	Waste-to-energy: municipal and industrial solid and liquid wastes (2017)	7025	MNRE
Hydro power	Large hydro >25 MW	150,000	CEA
	Small hydro <25 MW	15,000	MNRE
Other RE sources	Geothermal	10,000	IIT, Bombay
	Wave energy	6,014	WISE
Grand total		**39, 41,073**	**WISE**

Note: The potential estimates are subject to various underlying assumptions used by the estimating agency and need to be seen and evaluated in that perspective.

It should be mentioned that wind potential figures, both onshore and offshore, need validation with ground measurements. Similarly, the huge potential for solar PV and CSP, rooftop solar PV, and solar PV pumping estimated by WISE will also need validation with respect to ground-based measurements. Both wind and solar coupled with huge hydro energy potential can form a base for the transition to carbon- and fossil-fuel-free electricity generation. Bioenergy and geothermal technology, if explored appropriately, can be major additions and can give stability to the variable power network as their capacity factors are high. It can be concluded that RE potential is very large but needs validation from various government agencies. Once this is done, India can plan for long-term, secure, and emission-free power generation from RE sources.

RE Penetration of 75% in the Indian Grid

NAPCC has set a target of 15% RE penetration by 2020, which is likely to be achieved. Beyond 2020, the RE penetration level would have to be increased substantially so as to replace conventional power generation, which will be increasingly untenable on account of non-availability or high prices of coal and gas in the domestic and international markets. Three penetration scenarios for four decades with varying incremental RE penetration targets are shown in Table 7.17 and Figure 7.1 so as to achieve at least 75% RE penetration by 2050.

Table 7.17: Decadal RE Penetration Scenarios for India by 2050

Scenario	RE Annual Targets (Incremental)	Upto 2020	2021/2030	2031/2040	2041/2050
1. Advanced	Annual increment (%)	1.00	2.50	2.00	1.50
	Total RE (%)	**15**	**40**	**60**	**75**
2. Moderate	Annual increment (%)	1.00	2.0	2.00	2.0
	Total RE (%)	**15**	**35**	**55**	**75**
3. Business-as usual (BAU)	Annual increment (%)	1.00	1.5	2.00	2.5
	Total RE (%)	**15**	**30**	**50**	**75**

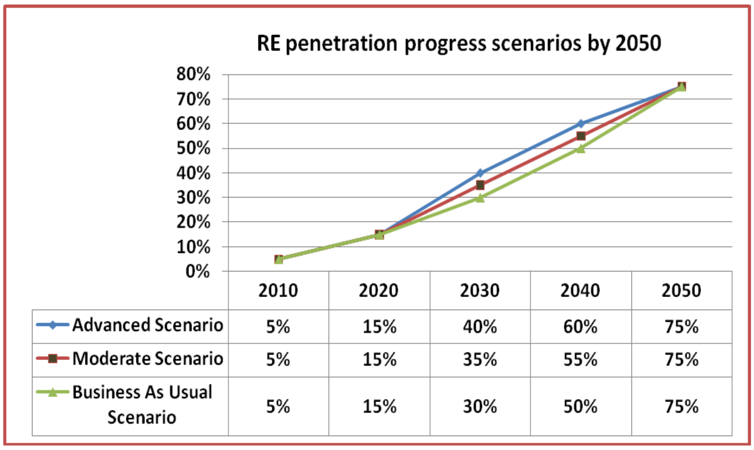

Figure 7.1: Decadal RE Penetration Scenarios by 2050 for India

In line with the high RE penetration scenarios as mentioned above and the huge potential estimates for RE and hydro power as shown in Table 7.16, RE installed capacity (in MW) needed by 2050 to achieve 50% and 75% RE penetration in India was worked out. Broadly, two different scenarios were created: (1) a wind- and solar-driven scenario because of their high resource potential, and (2) a no-water-requirement (in the case of wind) and low-water-requirement (in the case of PV) scenario for power generation. Based on the projected energy demand by 2050, three different scenarios for energy demand (3,500 BU, 4,500 BU, and 5,500 BU) with wind and solar driven options are attempted for RE penetration levels of 50% and 75% (Table 7.18). The CUF assumed to arrive at the installed capacity are as follows: wind: 25%; solar: 25%; biomass: 75%; small hydro: 35%; other RE technologies: 75%.

Table 7.18: Projected Installed Capacity (MW) and Generation (BU) of Renewable Energy under Various Scenarios by 2050 (For 50% and 75% RE under Wind Driven and Solar-Driven Options)

Electricity Demand by 2050, Scenario 1: 3500 BU								
	50% RE				75% RE			
	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)
Wind	1,050	479,452	700	319,635	1,575	719,178	1,050	479,452
Solar	438	199,772	788	359,589	656	299,658	1,181	539,384
Biomass	131	19,977	131	19,977	197	29,966	197	29,966
Small Hydro	88	28,539	88	28,539	131	42,808	131	42,808
Other REs -WTE	44	6,659	44	6,659	66	9,989	66	9,989
Total	**1,751**	**734,399**	**1,751**	**734,399**	**2,827**	**1,101,599**	**2,625**	**1,101,599**
Electricity Demand by 2050, Scenario 2: 4500 BU								
	50% RE				75% RE			
	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)
Wind	1,350	616,438	900	410,959	2,025	924,658	1,350	616,438
Solar	563	256,849	1,013	462,329	844	385,274	1,519	693,493
Biomass	169	25,685	169	25,685	253	38,527	253	38,527
Small Hydro	113	36,693	113	36,693	169	55,039	169	55,039
Other REs-WTE	56	8,562	56	8,562	84	12,842	84	12,842
Total (in MW)	**2,251**	**944,227**	**2,251**	**944,228**	**3,375**	**1,416,340**	**3,375**	**1,416,339**
Electricity Demand by 2050, Scenario 3: 5500 BU								
	50% RE				75% RE			
	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)	Wind Driven (BU)	Wind Driven (MW)	Solar Driven (BU)	Solar Driven (MW)
Wind	1,650	753,425	1,100	502,283	2,475	1,130,137	1,650	753,425
Solar	688	313,927	1,238	565,068	1,031	470,890	1,856	847,603
Biomass	206	31,393	206	31,393	309	47,089	309	47,089
Small Hydro	138	44,847	138	44,847	206	67,270	206	67,270
Other REs-WTE	69	10,464	69	10,464	103	15,696	103	15,696
Total (in MW)	**2,751**	**1,154,056**	**2,751**	**1,154,055**	**4,124**	**1,731,082**	**4,124**	**1,731,083**

India's maximum energy demand in 2050 is estimated at 5,500 BU and the likely RE penetration will be 50%–75%. Therefore, by 2050, maximum RE installed capacity will be 1,154 GW and 1,731 GW for 50% and 75% penetration respectively (Wind Driven). For 75% RE penetration under the wind-driven scenario, maximum 1,130 GW through wind and 470 GW from solar would be required and in the solar-driven scenario, India will need 753 GW from wind and 847 GW from solar. In addition, there will be a smaller contribution from other RE sector technologies (Table 7.18).

To arrive at the projections for RE capacity by technology, based on the present experience of sectoral contributions, it is assumed that wind and solar together will contribute about 85% share in RE energy demand (BU) as shown in Table 7.18 and the balance 15% will have to come from other RE technologies like biomass and small hydro, as shown in Figure 7.2.

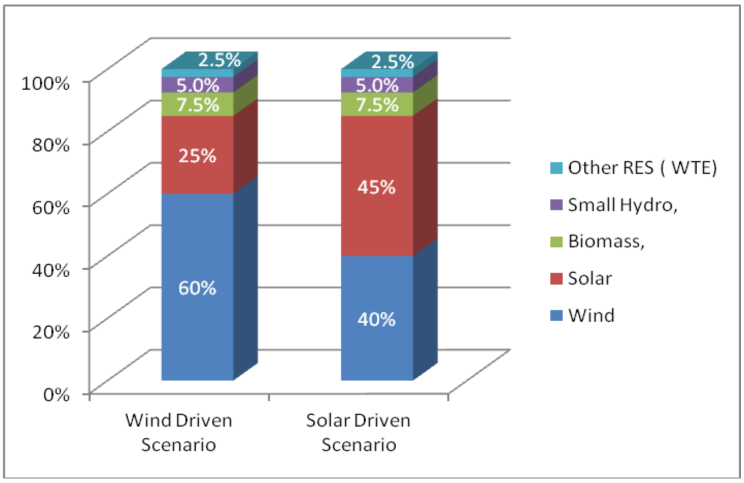

Figure 7.2: RE Energy Mix by 2050 (For Wind-Driven and Solar-Driven Scenarios)

LAND AND WATER REQUIREMENT

For 75% penetration and maximum 5,500 billion units projected demand under the wind-driven scenario, the land requirement for wind power would be 15,030 km^2 and for solar power, it would be 10,484 km^2, totalling to 25,514 km^2. Under the solar-driven scenario, the land requirement for wind power would be 10,020 km^2 and for solar power it would be 18,872 km^2, totalling to 28,892 km^2. Thus the total in either case would be less than 30,000 km^2 which is less than 1% of the gross land area of the country. Large scale promotion of rooftop solar PV systems can save large tracts of land from coming under solar projects. The maximum water requirement for solar power is estimated at 3,787 million m^3, which will be ~ 0.1% of total precipitation and ~ 0.4% of utilizable water in the country. Time will decide as to how far India can achieve this transition to RE, and innovation will be the key to this transition.

CHALLENGES AND REQUIREMENTS FOR ACHIEVING 75% RE BY 2050

The analysis has shown that it is possible to achieve 75% penetration of RE electricity in the grid by 2050 without considering large hydro power. However, there are many challenges and requirements for achieving this major energy transition in the next four decades. These challenges mainly relate to the following issues:

"Enough RE resources to the tune of 3,941+ GW including 150 GW of hydropower resources are available for greening the Indian economy. The total installed capacity of RE could range between 346 GW and 401 GW by 2032 (33% RE), and 1,731 GW by 2050 (75% RE)."

- Re-configuring, restructuring, and upgrading the Indian power grid.
- Grid balancing through firm power sources like hydropower, coal, and natural gas.
- Grid-scale energy storage and energy forecasting.
- Optimization of land use and land availability.
- Water availability and management.

THE FUTURE TRAJECTORY OF ELECTRICITY GENERATION

- Considering 8% growth rate, the final energy demand in 2045/46 would be 1858 mtoe (with constant real price) and 932 mtoe (with real price change of 3% per annum). The final energy intensity of GDP is projected to decline at the rate of 1.96% per annum from 2009/10 to 2045/46, even when we consider the highest GDP growth of 8% per annum and no real energy price change scenario. The rate of decline of energy intensity can be enhanced to 3.74% per annum if the final energy prices in real terms are allowed to rise at 3% per annum, inducing technical change for energy conservation.
- The gross electricity requirement ranges between 3,767–3,485 billion units in 2045 considering a growth rate between 7% and 8% per annum. On the other hand, a scenario of forced RE can deliver upto 2,980 billion units of electricity in 2045.
- By 2045, about 56.5% of electricity would be generated from RE sources with an additional 13% from hydro i.e. a total of around 70% of clean electricity in the grid can be achieved. In effect, around 75% clean electricity is possible by 2050.
- The policy choice implies a 1.5% per annum mandated growth rate of RE between 2022/2032, stepped up to 2% per annum for 2032/2045 and upto 2050.
- Enough RE resources to the tune of 3,941+ GW, including 150 GW of hydro power resources, are available for greening the Indian economy. However, to meet the 75% RE penetration requirement by 2050, an installed capacity of 1.7 million GW only would be required.
- India may also need to increase wind turbine manufacturing capacities from the current ~10,000 MW/annum to 20,000 MW/annum.
- Similarly, the solar manufacturing capacity will have to be stepped up from 2,000 MW/annum to perhaps 18,000–25,000 MW/annum by 2020, if accelerated targets are to be achieved.

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8. COMPARATIVE BENEFITS OF RE ELECTRICITY VIS-À-VIS COAL ELECTRICITY

This Section compares the impacts and benefits of coal-based power generation and RE-based power generation, in particular wind power and solar power. The comparison is conducted over major impact variables: impacts on land, impacts on water resources, impacts on forests, comprehensive impacts on air quality including human health impacts and direct impacts on rights of affected sections of people. While coal-based operations have large-scale negative impacts which are extensive over space and time, RE-based generation has zero or very low-scale of impacts. Various benefits, both direct and indirect, that accrue from RE-based power generation are presented in this section.

COMPARATIVE LAND BENEFITS

Land for Coal-based Projects: The entire land requirement for establishment of a thermal power station has been officially published by the Central Electricity Authority, Govt of India. The documents cover in detail the land requirements for main plant and auxiliaries, boiler and turbo generator with transformer yard, coal handling system, raw water reservoir and water system, switchyard, ash handling system, FGD system, station facilities, other yards, permanent stores, road, landscaping and green belt, ash dyke, facilities outside power plant, raw water intake system and corridor, and corridors for ash slurry pipelines and townships, etc. On an average, the land requirement is about one acre per megawatt.

However, this is the estimate of land required only for thermal power projects per plan period; it does not include land for coal mines and additional land for railways to supply coal to the new power projects. When all these factors are considered, land requirement for coal-based power projects will equal that of wind or solar power projects. The land acquisition will be mostly concentrated in a few central Indian states where coal is being mined or in a few coastal areas of Gujarat, Maharashtra, and Andhra Pradesh, leading to large requirement for resettlement and rehabilitation.

Land for RE Power: In quantitative terms, the land requirement for RE-based generation will be equal to coal-based generation, plus coal mining per installed MW. But in this case, land will not be destroyed permanently (mining) and can be reused after 25 years. For major RE sources—wind and solar—there will almost be no serious land related environmental impacts. The land requirement can be quite decentralized rather than in large pockets at single locations due to the modular nature of RE deployment. Rooftop solar will not require land, nor will solar pumpsets in farming areas. Land for wind and solar generation will be required mostly in arid and semi-arid areas where land productivity and population pressures are low. Developments in IT make remote monitoring of RE projects possible for O&M purposes, resulting in minimal requirement of land for housing and the related infrastructure. Due to their smaller unit sizes and dispersed locations, RE projects will be free of the R&R requirements affecting sensitive and marginal populations. Consequently, they will escape the costs, delays, local opposition and antipathy caused by large-scale projects, whether for mining or for power generation.

COMPARATIVE WATER BENEFITS

Water for Coal Thermal Power: In the entire cycle of coal-based thermal power generation and coal mining, water is required in large quantities in different operations viz. coal washeries, water for cooling used in towers of thermal power stations (60 to 100 litres per kWh), make up water for boilers (3 to 4 litres per kWh), water for slurry removal, etc.

For evaluating the full impact of water abstraction for the purposes of thermal power generation, a GIS database of river basins with their annual discharge along with exact information on power plant locations, sizes, sources of water, and type of technology used would be required. An estimate based on currently operating thermal power plants in Vidarbha region of Maharashtra indicates that the average water requirement per MW is 23,000 m^3/year or 3.83 litres/kWh generated. This obviously represents just the consumptive use of water and not water abstraction for cooling, if any. It is known that major thermal plants in Maharashtra – Parli and Chandrapur have faced temporary closure or backing down of power generation due to water shortage in summer or drought. This may be considered a portent for the future.

Water Neutrality of RE Technologies: None of these impacts will occur for most technologies of RE power generation, as neither wind nor solar PV use water in significant quantities. Wind power uses no water, and solar PV plants require water only for cleaning the panels. The quantities required would be minimal and could be recycled. Only concentrated solar thermal power (CSP) requires water if based on steam cycle and the water requirement for cooling can be reduced by air cooling. In the case of CSP (in comparison to coal), the additional water used for coal washing, slurry transport and ash disposal required for coal-based generation will not be needed, avoiding the downstream effects of such water use. Even when CSP (wet cooling) requires water for cooling, studies in limited states have shown that water requirement would be considerably less than coal-based projects. Hence, depending on the RE technology used, the water impacts will be minimal or small. Saving major river basins and coastal areas from destruction (both in terms of water quality and quantities abstracted) will be one of the greatest benefits of RE-based generation in the future.

COMPARATIVE BIOTIC BENEFITS

Coal Projects and Forests: These will be cumulative, consisting of impacts from coal mining and impacts from thermal power generation. The impact of coal mining includes direct deforestation due to forest clearance for coal blocks, impact on surrounding forests due to overburden runoff, bisection of forests for railway lines or roads, impacts on wildlife due to blasting, wildlife deaths due to transportation corridors in forest areas/sanctuaries, mining dust from operations, etc.

***"RE technologies (except CSP) are largely water neutral. In an emerging water-stress situation due to climate change and environmental destruction, this is a huge benefit* vis-*à*-vis coal based thermal projects – some of which are facing closure due to non-availability of water for cooling."**

Impacts on forests due to coal-based power generation include impacts due to air pollution which can extend upto 80 kms downwind from thermal plants (conservatively estimated), destruction of forest areas of both the Western Ghats and Eastern Ghats due to pollution from coastal power plants on the western and eastern coasts, acid rain caused by CO_2, SO_x and NO_x being dissolved in precipitation, flyash disposal on surrounding forests/habitats being carried by wind, and impacts on forests due to surface water abstraction/impoundment/thermal pollution of water.

Minimal Impact of RE Technologies: In the case of RE-based generation systems, almost none of these impacts on forests would occur, provided the projects are not located in existing forest areas. This can be easily controlled in the process of granting forest clearances. Projects on forest fringe areas would not have any impacts on wildlife habitats or biodiversity, as they would generate no pollutants, noise (marginal noise in the case of wind turbines), or thermal effects, nor have any permanent transport linkages. Any impacts would be linked to the construction phase, particularly in the case of wind projects which require roads for transport of the large sails, turbines and tower materials and heavy duty cranes for assembly/dismantling. These impacts of wind power projects can be mitigated by use of helicopters for transporting heavy materials, thereby avoiding requirement of wide roads. Even this requirement is likely to be minimal in the case of solar PV projects. Solar thermal projects on a large-scale would have environmental impacts much lower as compared to coal-based projects, due to the absence of transport linkages, fuel linkages, and output-side effluent streams. RE-based technologies also have the potential of supplying electricity to forest-based and remote communities through stand-alone, RE microgrid systems.

COMPARATIVE AIR QUALITY BENEFITS

Coal and Air Quality: These impacts mostly occur due to thermal power generation and will be on a much wider scale than from coal mining. These impacts are far more subtle. There are 14 pollutants in the airborne stream emerging from the smokestacks of thermal power stations. These include the five classical pollutants, namely SO_2, NO_x, particulates, CO, and ozone; other toxic pollutants include arsenic, cadmium, chromium, mercury, nickel and lead, all of them being heavy metals, injurious to human health when inhaled even in small quantities. The balance of the pollutants are hydrocarbons. The following impacts and scale of ranges need to be considered: impacts on human health due to particulates, sulphur and nitrogen oxides and heavy metal pollutants at a distance ranging from hundreds to thousands of kilometres; impacts of acid rain and ash deposition on croplands, forests, wildlife habitats, water bodies, fisheries and property; impacts of heavy metal pollution through food pathways including crops, fish and animal products, as well as drinking water.

Amongst the most disturbing of the latest research findings are the emerging link between radioactive emissions and coal combustion in thermal power stations. The potential exposure and impact pathways include inhalation, deposition on soil and water bodies, leaching into subsoil waters, both through the aerial pathway as well as ash storage and disposal. In addition, it may be emphasized that the above impacts do not include the global impacts due to CO_2 emissions, which are quantitatively very large and contribute to global warming and long-term climate related damages.

RE Technologies Provide Clean Air: In comparison with coal, none of the major RE sources – wind, solar PV, solar thermal, and small hydro – will have any impacts in terms of air pollution whatsoever. Biomass-based plants will have local impacts due to small plant sizes, but by their very input requirements, such plants will have to be based at a distance from each other in order to have non-overlapping areas of biomass supply. The air pollution impacts in the case of biomass combustion/biomass gasification have not received the requisite attention. Plants based on biomethanation technologies would have far lower SPM emissions and would be "cleaner" than combustion-based biomass technologies, just as gas-based power plants are considered less polluting compared to coal-based power plants.

COMPARATIVE IMPACTS ON PEOPLE

Coal and People: Much of the impacts would be on indigenous communities living in forests or fringe areas. This is a sensitive issue because many of the affected people would be protected by the Sixth Schedule of the Constitution specifically designed to protect tribals and *dalits*. They would have rights under R & R policies, PESA, mineral and forest rights, etc. Even if these people are not displaced or their lands acquired, consideration has to be given to the impacts on their health due to air and water pollution, negative impacts on their livelihoods due to adverse impacts on agriculture, forests, local wildlife and local fisheries. These would be cumulative area level impacts, super-positioning impacts from both coal mining and thermal power generation, combined with transportation impacts and impacts of water impoundment.

Benefits of RE-Based Generation to People: RE-based generation or microgrids are capable of meeting the energy needs *in situ* without destroying existing environmental resources, and instead, enhancing productivity of use of existing environmental resources. The large cost of grid extensions to remote villages can be avoided and the same investment resources can be instead devoted to enhancing RE-based supply to remote clusters. Local employment generation can take the form of O & M activities by educated members of local communities, with external remote IT-based monitoring and back-up from larger towns/cities in the region. Increased employment will also occur through telecom connectivity once electricity is made available, as well as enhanced productivity in agriculture and local processing. Advanced technology could play a productivity and employment enhancing role without environmental or resource destruction or degradation of the local community structure.

COMPARATIVE CLIMATE BENEFITS

Climate Impact of Coal Electricity: In the National Electricity Plan (NEP), 2012, CEA has considered three scenarios: Low RE, Low Gas; Low RE, High Gas; and High RE, High Gas. In continuation with the two scenarios used in the previous section, we reproduce the proposed generation mix for two scenarios: Low RE, Low gas (coal-dominant LREG); and High RE, High gas (RE-dominant HREG). Table 8.1 projects the energy mix envisaged in the NEP, 2012.

Table 8.1: Future Technology-wise Capacity Additions, (in MW), NEP 2012					
Technology	Existing (March 2012)	Low RE, Low Gas (Coal-dominant)		High RE, High Gas (RE-dominant)	
		12th Plan (2012/17)	13th Plan (2017/2022)	12th Plan (2012/17)	13th Plan (2017/2022)
Coal	112022	66600	49200	51400	34000
Gas	18381	1086	0	13086	13000
Diesel	1200	0	0	0	0
Nuclear	4780	2800	18000	2800	18000
Hydro	38990	9204	12000	9204	12000
RE	24503	18500	30500	30000	45000
Total	**199876**	**98190**	**109700**	**106490**	**122000**

The NEP, 2012, document assumes weighted average specific emission values for fossil-fuel-based generation (Table 8.2).

Table 8.2: Specific Emission Values of Coal and Gas		
Technology	Tonnes of CO_2/MWh	
	Coal	Gas
Old technology	1	0.46
New technology	0.88	0.34

All the other technologies are assumed to have a zero footprint since no diesel-based capacity addition is planned. Based on the above assumptions, the projected emissions from energy generation are compared with emissions from coal-based capacities. Table 8.3 captures the estimated annual CO_2 emissions and the cumulative additions upto 2032 for the LREG and HREG scenarios.

Table 8.3: CO_2 Emissions from Coal-based Generation up to 2032 for the LREG and HREG Scenarios		
Scenario	Annual Emissions (million tonnes)	
Low RE, Low Gas	Coal	Total (Power Sector)
End of the 12th Plan (March 2017)	1004	1028
End of the 13th Plan (March 2022)	1246	1269
End of the 14th Plan (March 2027)	2016	---
End of the 15th Plan (March 2032)	2753	---
High RE, High Gas	Coal	Total
End of the 12th Plan (March 2017)	922	956
End of the 13th Plan (March 2022)	1082	1127
End of the 14th Plan (March 2027)	1430	---
End of the 15th Plan (March 2032)	1538	---

Figure 8.1 captures the emissions trajectory of the LREG and HREG scenarios upto 2022.

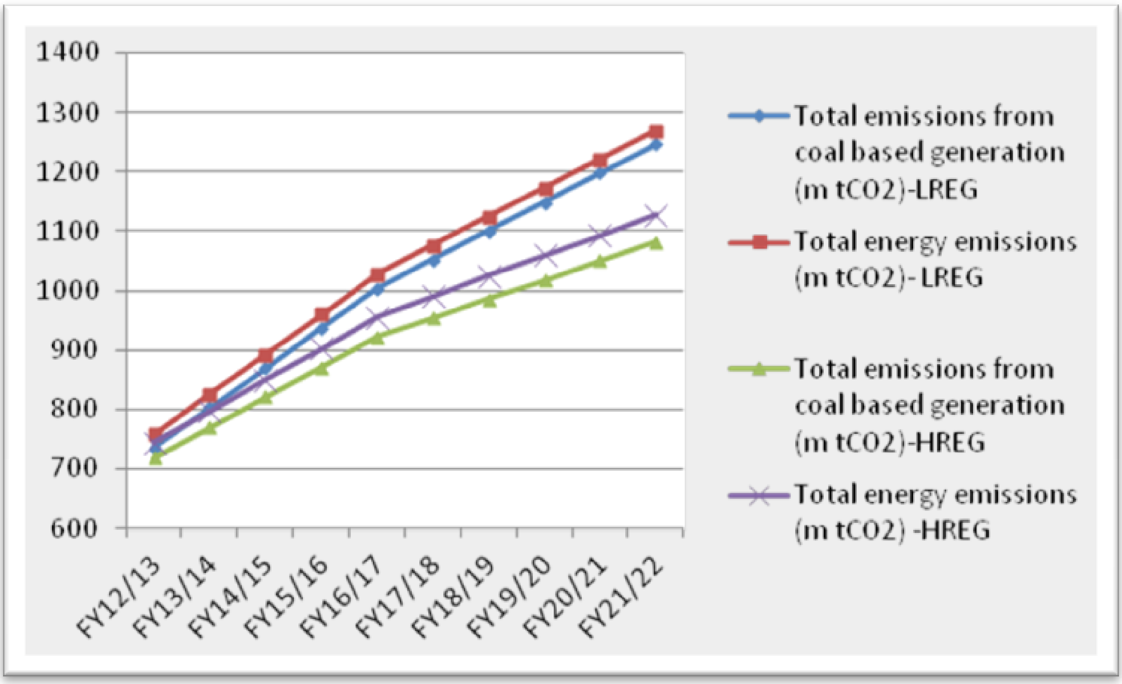

Figure 8.1: Total Emissions for the LREG and HREG Scenarios upto 2022

The difference in both the scenarios is hardly significant. Even assuming a High RE, High Gas scenario, India seems to have locked itself to energy related emissions of about 1082 million tonnes of CO_2 from the power sector itself upto 2022. This does not include CO_2 and CO_2 equivalent from other sectors. If we compare this figure with the total emissions from the power sector (715.8 tonnes of CO_2 in 2007), we are looking at a minimum of 51% increase in CO_2 emissions from 2007/2022 in the power sector alone, even with High RE, High Gas scenario upto 2022.

Since the bulk of emissions on account of energy generation are because of coal, it is worth looking at the emission levels in 2032. Based on the coal-based capacity addition, plan scenarios beyond FY 2021/22 up to FY 2031/32 have been developed by WISE (see Fig 2.3). WISE's projections have proposed only 21,675 MW addition during the 14th Plan (2022/2027) and 13,645 MW during the 15th Plan (2027/2032). If such an approach is adopted, emissions will go down from a probable 2,753 million tonnes in 2032 under the LREG scenario to 1,538 million tonnes under the proposed HREG scenario. Figure 8.2 captures the trajectory of emissions up to 2032 based on these projections. The wide divergence between the two lines in the graph shows the clear distinction between a business-as-usual and a proactive scenario, where active interventions aimed at climate-friendly policies and alternative technologies can change the emissions impact in a big way.

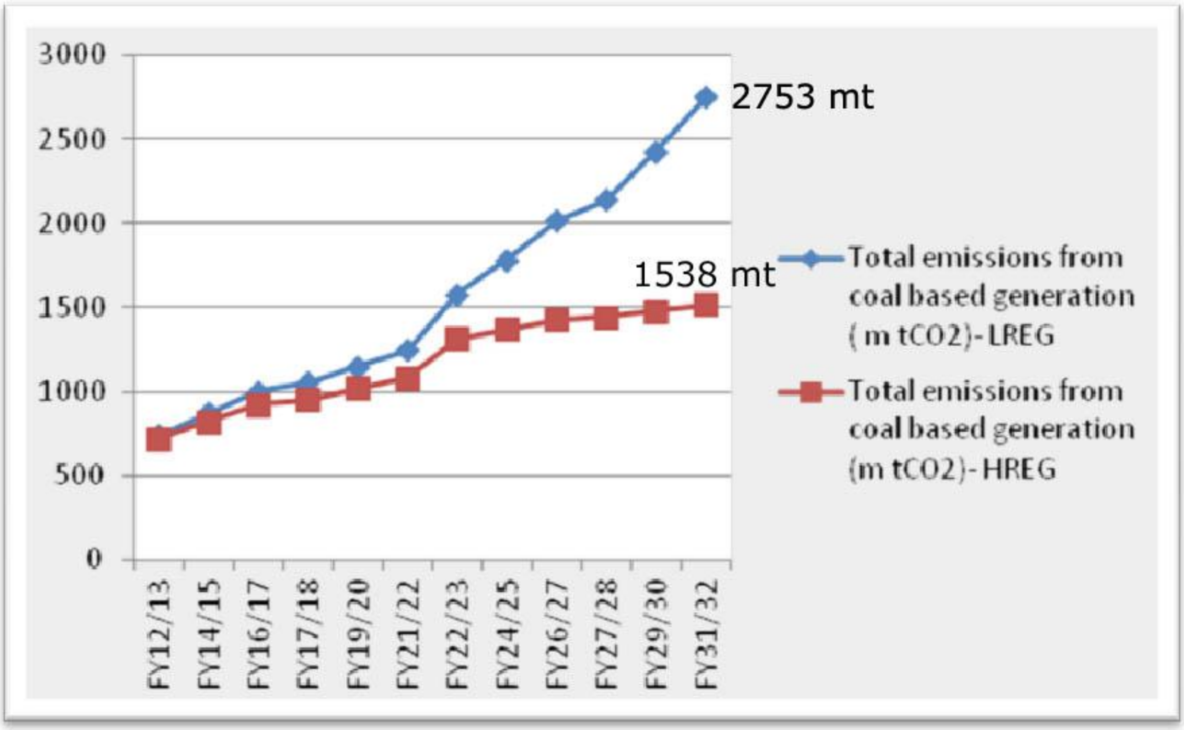

Figure 8.2: CO_2 Emissions from Coal-based Generation upto 2032

Climate Benefits due to RE Maximization: A major benefit of accelerated, policy driven RE deployment (as shown in Table 7.18 in Section 7) is on account of reduced CO_2 emissions into the atmosphere, as computed for the three different scenarios in Table 8.4. The computations are made on the basis of the specific emissions of new coal technologies, on the assumption that the electricity to be generated from RE sources replaces equivalent units generated through coal combustion, with an emissions factor of 0.88 tonnes CO_2 per MWh.

Table 8.4: Avoided CO_2 Emissions due to Accelerated RE Deployment		
Scenario 1: Electricity demand by 2050: 3500 BU		
50% RE (Wind and Solar driven)		75% RE (Wind and Solar driven)
RE units generated (BU)	1750	2625
Avoided emissions (MT)	1540	2310
Scenario 2: Electricity demand by 2050: 4500 BU		
50% RE (Wind and Solar driven)		75% RE (Wind and Solar driven)
RE units generated (BU)	2250	3375
Avoided emissions (MT)	1980	2970
Scenario 3: Electricity demand by 2050: 5500 BU		
50% RE (Wind and Solar driven)		75% RE (Wind and Solar driven)
RE units generated (BU)	2750	4125
Avoided emissions (MT)	2420	3630

It can be seen that higher the substitution of coal by RE electricity, the greater is the benefit of avoided CO_2 emissions, being as high as 3.63 billion tonnes per annum in 2050 in Scenario 3. This is a very significant benefit, which is one-third of the annual carbon absorption capacity of the earth systems.

COMPARATIVE BENEFITS ON LEAD TIME/GESTATION

Gestation Period of Thermal Projects: In coal combustion technologies, the incrementally higher efficiencies and lower costs of generation are obtained through larger unit sizes utilizing higher steam pressures and temperatures. Typically, unit sizes have moved from 200 MW to 500–800 MW, with multiple units being deployed at a single project site. The larger unit sizes imply larger boilers, larger turbines, larger coal handling plants and machineries, higher smokestacks, larger transformers and so on. These sizes present tremendous problems of logistics during manufacturing, transportation, erection, and lifelong maintenance, requiring the use of heavy duty machinery for every operation.

Large size units further add up to delays, which then reflect in an additional burden of interest costs to be incurred before commissioning and the start of repayment and overall cost-escalation. In analogous terms, the same holds true in the case of gas-based as well as nuclear projects. While gas-based projects are relatively more modular, they involve delays in laying dedicated pipelines which require land acquisition and involve public safety aspects. Nuclear projects also involve large reactor sizes and turbines, the construction of huge containment structures of concrete, extreme care in implementation of storage structures for hazardous radioactive materials, sophisticated instrumentation, dedicated systems for transportation of nuclear materials, wastes for reprocessing, and so on. It is generally accepted that a coal thermal project needs about 5 years for commissioning after completion of all statutory and financial requirements; this may be marginally lower for gas-based projects and could be much higher in the case of nuclear projects (upto 10 years), depending on the extent of regulatory scrutiny. In all cases, these add to financial costs through the rising burden of interest, prior to the start of production and repayment, besides huge gestation periods leading to impairment in fast ramping up of capacity.

***"RE maximization as proposed in this study could avoid up to 3.63 trillion tonnes of CO_2 emissions per annum* by 2050."**

Modularity and Low Lead Time of RE: By contrast, the principal RE technologies are far more modular. The largest unit sizes for individual wind turbines may range from 1.5 MW to 3.1 MW; this means that most components can be mass produced bringing down costs; they can also be quickly transported and assembled on site. Even the large-sized blades can be easily handled by transporters; they can even be transported by helicopters to remote locations lacking road infrastructure. The same is true for solar PV projects whose unit sizes could be as low as a few kW or MW, avoiding all the complicated logistics associated with large unit sizes.

Many of the components can be manufactured in medium or even small industries and even onsite construction of projects can be undertaken by smaller service companies, leaving the larger RE manufacturers to act as system integrators and project designers. With smaller project sizes, lenders are not overwhelmed by the consideration of risk factors causing project failure; even smaller banks could finance smaller RE projects without recourse to creation of consortia of banks to spread risks. These diverse activities synergize to significantly reduce deployment delays at the project site, so that RE projects can be commissioned much faster and start the process of payback too faster. It is estimated that an RE project can be commissioned within six months to one year (except in the case of CSP which may take upto two years) This saves upto 3–4 years of the cost component of 'interest during construction', improving project viability and feeding electricity into the grid much faster than conventional projects. This also means that benefits to the larger economy are delivered much faster, avoiding the lost production downtime in the economy due to electricity shortages in the grid. Capacities can be ramped up very fast and scaling up can be achieved in very short durations.

OTHER BENEFITS OF RE MAXIMIZATION

Other benefits of RE maximization include large-scale employment generation in the RE sector, increased availability in the transportation system due to avoided transportation of coal, foreign exchange savings on diesel/fuel oil in thermal generation, freeing up of infrastructure and avoided infrastructure investments (ports, roads, foreign infrastructure, water pipelines) and overall benefits to the macro-economy because of reduced risks and uncertainties for continued economic growth. Here, only the benefits from employment generation and the benefits to the transportation system are elaborated in some detail.

Benefits from Employment Generation: The employment generation potential for the two major RE technology-driven scenarios upto 2020 (at 15% RE penetration) have been calculated in Table 8.5, while till 2050 (at 75% RE penetration) is shown in Table 8.6.

Table 8.5: Employment Generation Potential for Various RE Sources up to 2020 (at 15% RE Penetration) for Wind and Solar Scenarios				
RE Technology	RE Capacity Addition (MW) (2011/2020)		RE Manpower Requirement (in millions)	
	Wind-driven	Solar-driven	Wind-driven	Solar-driven
Wind	59,965.00	37,028	0.899	0.555
Solar	9,962.00	35,452	0.199	0.709
Biomass	7,421.00	7,236	0.371	0.361
Small Hydro	2,823.00	2,813	0.025	0.025
Others REs (WTE)	123.00	253	0.006	0.011
Total	**80,294.00**	**82,782.00**	**1.5**	**1.66**

Table 8.6: Employment Generation Potential for Various RE Sources up to 2050 (at 75% RE Penetration) for Wind and Solar Scenarios				
RE Technology	RE Capacity Addition (MW) (2011/2050)		RE Manpower Requirement (in millions)	
	Wind-driven	Solar-driven	Wind-driven	Solar-driven
Wind	907,013.18	598,794.01	13.61	8.98
Solar	384,243.31	692,462.49	7.68	13.85
Biomass	35,298.57	35,298.57	1.76	1.76
Small Hydro	51,627.38	51,627.38	0.46	0.46
Others REs (WTE)	12,748.79	12,748.79	0.57	0.57
Total	**1,390,931.23**	**1,390,931.23**	**24.00**	**25.63**

There will be high prospects of quality employment generation by the RE sector, even with only 15% RE penetration, with around 1.5 to 1.6 million jobs generated by 2020 (Table 8.5). By 2050, this can increase upto around 24 to 25 million jobs (Table 8.6). Sustainable employment growth in the long term is possible along the RE pathway and can be planned. These will not be low-end, drudge labour jobs (unlike underground coal mining) but well paying, skilled and long-term jobs, relatively free of the vicissitudes of the market economy since energy demand will continue to be strong. The employment will be generated in a dispersed, decentralized mode, so that incomes and benefits will flow geographically to all parts of the country. This constitutes an enormous macro-economic benefit to the economy.

Benefits to the Transportation System: Transportation infrastructure to carry the vast additional quantities of coal will need large public investment in railways, ports and roads; it will also commit the country to increasing expenditure on diesel in the transportation system which in turn will add to the foreign exchange burden for the country, the subsidy burden of the central government (if diesel subsidies are continued), as well as additional CO_2 emissions. These implications of the commitment to coal have not received the analytical attention that they deserve. The additional investment into capacity expansion of the transportation sector will be of the magnitude of tens of thousands of crores, an investment which can be avoided if RE sources are rapidly harnessed. In effect, instead of investing in additional transportation, the financial resources would be better employed in supporting the expansion of RE power generation, which would not entail further operational subsidies for diesel, foreign exchange, etc.

"RE maximization can generate upto 1.6 million jobs by 2020 and 25 million jobs by 2050 without causing environmental destruction. This constitutes an enormous macro-economic benefit to the economy."

MORE BENEFITS NEED TO BE QUANTIFIED

This section has only attempted to indicate some comparative, qualitative benefits of RE-based generation vis-à-vis coal. Quantification of benefits in monetary terms per megawatt of RE installed is not within the scope of this study. Such quantitative studies are worth undertaking by widening the ambit of above comparisons to more areas like:

- The cost advantages of RE power on a lifecycle basis vis-*à*-vis coal-based power considering the variability of the price of coal.
- Savings on transmission infrastructure because of the decentralized nature of RE generation vis-*à*-vis centralized generation of thermal plants.
- Reduction in transmission losses since RE generation happens at the tail end of the grid, whereas thermal power needs to be transported to large distances from a centralized generating station.
- Macro-economic benefits of a power generation system, free from dependence on fossil fuel imports.

* * *

9. AN ALTERNATIVE, FUTURE-ORIENTED POLICY FRAMEWORK FOR ELECTRICITY

While the major thrust of the study has been on the analysis and implications of the risks of a policy centered on coal-based electricity for the future, we have also considered the alternative possibilities offered by RE-based electricity for the future. The coal-centric pathway is coupled to projections based on high growth rates of the economy. These projections result in a huge over-projection of future electricity demand, consequently a huge demand for coal in the future.

DECOUPLING ENERGY FROM GROWTH

There is abundant literature on the decoupling of energy from growth. However, the policy stance adopted has more or less completely ignored this body of evidence. On the other hand, we have shown a number of independent projections of future electricity demand for the country: these project half or less than half of the electricity as required in the future. Quantitatively, the official policy projects the demand in 2050 to be between 9,000–12,000 BU of electricity, whereas the alternative demand projections show a range between 3,500–5,500 BU per year. This in itself has huge implications for future electricity choices—the official projections would virtually rule out a sustainable electricity system, whereas the alternative projections show the distinct possibility of a sustainable, green electricity system based on green and clean sources of energy. This is the stark policy choice that has to be confronted; the sooner the better.

Whereas the official policy approach is weak in terms of considerations of policy that are external to the electricity sector, such as implications for sustainability of the environment, biodiversity, protection of the rights of socially vulnerable populations, macro-economic risks, health damage consequences and climate related implications. The alternative approach has presented evidence wherein both internal and external factors and risks in electricity generation are brought together in a more seamless way. This provides an insight into the necessary policy framework that needs to be evolved for the future.

THE INTERNAL AND EXTERNAL FACTORS

For evolving such a policy framework for electricity, we need to separate the internal factors of policy from the external factors or implications of policy.

The internal factors driving electricity policy would include: technological factors, economic valuations (including financial factors), subsidies and incentives as promotional factors and the electricity regulatory requirements in conformance with legal requirements. These would cover generation, transmission and distribution of electricity along with the infrastructural requirements for facilitating the production of electricity, and its delivery to end users. All alternatives for electricity generation-transmission-distribution-conservation would be placed on a level-playing field, for purposes of comparison.

“We can transition into a clean energy system without compromising on our economic development. Such a transition does not exclude coal, which would need to be used as a ‘bridge’ fuel to help smoothen the transition.”

The external factors of policy would include specific inputs and limitations from other policies: policies of environmental sustainability including forests, water, land, biodiversity and human and animal health and welfare; social policies including rights legislation, constitutional provisions and judgements; macro-economic factors including economic sustainability, balance of payments, risks and uncertainties, economic and national security considerations and long-term employment and livelihood considerations; climate policies including overall emissions, international obligations and likely impacts of global warming on future economic, social and environmental performance. All alternatives would be examined across all relevant external factors placed on a level-playing field for purposes of comparison.

Any policy for the electricity sector would have to run the gauntlet of both the internal and external factors, with the trade-offs being transparently made in the public domain of policy and clearly stated. This would be long-term, inclusive policy drawn up through an inclusive process of public policy making. This is not happening today, with the consequences becoming apparent. The internal factors are being given excessive weightage while the external factors are being given artificially low weightage in the policy formulation process. This is resulting in policy deadlock, poor sectoral performance, unsatisfactory governance and affecting overall economic and social performance. All of these are avoidable if healthy processes of policy formulation are adopted, resulting in healthy, long-term and stable policies. In the evaluation of particular projects, it may turn out that the external factors taken together may outweigh the internal factors and the policy framework should be open to this possibility.

PITFALLS OF THE CURRENT POLICY

In such a process of arriving at decisions, all the costs and all the benefits of every electricity alternative would be subject to criteria that are: techno-economic, environmental, social, climate, macro-economic, security and governance. It is our submission that if the current coal-centric electricity policy is subjected to the dispassionate scrutiny of these multiple criteria, it will fail to cross several hurdles; these hurdles will only rise higher in the future. Even if some of the criteria are non-quantifiable, it is better to identify them and leave them open to judgement and trade-off rather than to deny that they exist (zero value) or that they matter. Wisdom requires that we display adequate foresight through foreknowledge, by changing the policy formulation processes, rather than learning through bitter and fractious experience.

A quick look at three different situations may serve to indicate the pitfalls of the current policy process.

1 The performance in terms of capacity addition by the conventional electricity sector over the last two plan periods leaves much to be desired as well as much to be explained. In the 10th

plan period, the original capacity addition target was 44,185 MW while the achievement was 27,940 MW, of which 6,760 MW was added by RE, leaving 21,180 MW as the real addition from thermal, nuclear and hydro. In the 11th plan period, the original target was 92,700 MW, which was downscaled to 74,203 MW midway through the plan. The actual performance achieved was 67,344 MW, which includes the capacity additions by the RE sector of 12,380 MW. If this is deducted, the performance of the conventional sector is roughly 60% of the original target. This requires rational explanation, not blame-game tactics. The MoEF has been consistently blamed for delays in clearances but this is hardly an explanation, no matter how often repeated. Our previous policy analyses as well as the outline of alternative policy and process indicates that several other policies, laws and judgements have erected a ring fence around electricity policy and the proper explanation for poor performance lies in examination of the processes due to which the ring fence has been erected.

2 The second situation arose in the State of Florida in the US. The Florida Power and Light Company (FPL), an electricity utility, approached the Florida Public Service Commission with the plea to establish two ultra supercritical pulverized coal thermal units to meet the projected increase in electricity demand. Several public minded civil society organizations including The Sierra Club, Florida Wildlife Federation, Natural Resources Defense Council and others pleaded before the Public Service Commission to be heard in the matter of the determination of need for major new power plants. After very detailed and complex arguments from both sides, which involved examination of sixteen alternative scenarios, the Commission ruled that: "In making its determination, the Commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, and whether the proposed plant is the most cost-effective alternative available. The Commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant.

The Commission ruled that, "Our decision is based upon our analysis…and our determination that FPL has failed to demonstrate that the proposed plants are the most cost-effective alternatives available, taking into account the fixed costs that would be added to base rates for the construction of the plants, the uncertainty associated with future natural gas and coal prices, and the uncertainty associated with currently emerging energy policy decisions at the state and federal level." By its Order, the petition was denied.

3 A recent study released by the Union of Concerned Scientists indicates that 353 coal-fired plants across 31 states of the US should be considered for closure because the electricity they produce will no longer be economically competitive. These plants collectively represent 6% of all power generated in the US, roughly 59,000 MW of generation capacity; they average about 45 years of age, well beyond the 30 year expected coal plant life span and are operating at

47% of capacity. About 70% of these lack equipment for control of three of the four most harmful emissions – sulphur dioxide, nitrogen dioxide, mercury, and soot. If these plants are upgraded with modern pollution controls, they would not compete with natural gas or wind generation. The report argues that apart from the adverse economics, the closure of these plants would greatly benefit human health, bring about a significant reduction in US emissions in the power sector and expand the market for clean energy sources. They represent "an historic opportunity to accelerate the transition to a clean energy economy, improve public health, reduce global warming, and create a more resilient energy system."

These instances indicate that a limitless expansion of coal-based thermal generation is likely to be increasingly challenged, both by policy processes internal to governance as well as by processes external to policy-making. Hence the need to review the processes through which policies are formulated, to avoid future deadlock and lack of effective performance.

ALTERNATIVE APPROACHES TO FUTURE ENERGY POLICY

In the **internal** part of the policy process related to coal-based electricity for the future, the following factors need to be considered:

- Examination of future electricity projections and methodologies.
- Subsidies to coal-based electricity generation at both central and state levels, currently incorporated into various policy documents of different ministries/departments of central and state governments.
- Evaluation of transportation subsidies to railways for coal transportation for thermal power generation.
- Failure to reduce T&D losses, despite central financial incentives for the purpose.
- Grid network expansion costs and alternatives (e.g. smarter grid technologies).
- Slow progress in electricity conservation despite enactment of the Energy Conservation Act, 2001.
- Electricity regulatory commissions' (ERCs) inability in enforcing electricity conservation.
- Role of ERCs in prescribing preferential tariffs for RE and off-grid RE systems.
- Need for long-term stable RE support policies and targets.

Specifically with respect to bringing renewable energy into the internal drivers of policy, the following issues need to be considered:

- Phased increase of RPO for the long-term, at 1% per annum increase upto 2022 and at 1.5% per annum of green electricity in the grid for the period from 2022 to 2032, and 2% per annum from 2023 to 2050.
- Encouraging long-term growth of RE manufacturing capabilities within the country through committed policy support; this could be achieved through both encouragement to foreign direct investment/technology transfer and through the domestic investment route, by making available long-term debt financing available via public savings i.e. banking, insurance and pension funds.

The latter route would lower risks for the macro-economy and would require greater efficiency in collection and payment mechanisms.

- Policy for shaping the future grid to accommodate the expansion of RE sources of generation: net metering, supply standards, DISCOM obligations, payments adjustments, etc.
- Long-term policy for human resources development, both within and outside government, to create the necessary skill sets to match the growth of RE in the economy.

In the external part of the policy process related to coal-based electricity, the following aspects are to be brought in:

- Unambiguous statement of long-term policy intent which places both the internal and external factors governing electricity policy on a level-playing field, with a policy commitment to examine all alternatives on a methodologically equal footing, and use of multiple criteria for decision making; this will result in less *adhoc* or arbitrary decisions which result in implementation deadlock. This will be a policy stance that recognizes the reality that has already emerged. A corollary will be the withdrawal of the Integrated Energy Policy (IEP) which has not met the demands of the emergent reality in multiple dimensions; the IEP is already dead, it has to be accorded a decent 'burial' in order to prevent further damaging dissonances. The Low Carbon Report can lead the way to new, long-term policy after inclusive national debate on its manifold future implications, including on responding to the threat of climate change.
- Evaluation of externalities of coal-based electricity generation, with best internationally available methodologies.
- Evaluation of social impacts of coal mining/power generation in line with new legislation on R&R and land acquisition.
- Clear acceptance of rights-based legislation/judgements and ensuring their implementation by state governments and all ministries.
- Clear stance on long-term, macro-economic implications of importing coal for power generation in tune with the FRBM Act.
- Clear national policy stance in favour of reduction of coal-based emissions with assigned targets, whether mandatory in international terms or as national voluntary commitment.

With respect to the external drivers of policy, the following issues need to be urgently considered:

- The need to accelerate GIS mapping on a common platform across the following sectors: forests/wildlife/biodiversity, water resources on the basis of river basins, environment on the basis of location density and cumulative environmental impacts, GIS mapping of coal mines and coal reserves, mapping of present and future thermal power projects and related infrastructure.
- Increase in the impact radius of flue gas emissions from thermal plants to at least 80 km from stack.
- Enforcing social protection policies for vulnerable groups across all states as an overriding national commitment and priority.

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About WISE

The World institute of Sustainable Energy (WISE) is a not-for-profit institute committed to the cause of promoting sustainable energy and sustainable development, with specific emphasis on issues related to renewable energy, energy security, and climate change. Since its inception in 2004, WISE has pioneered many important initiatives in the above areas. These include:

- Policy research and policy advocacy in critical areas like wind power and solar energy, future of coal electricity in India, transition to a sustainable energy system by 2050, etc.
- Piloting a model Renewable Energy law for India.
- Developing a renewable energy pathway for achieving the target of 15% RE by 2020, as specified by the National Action Plan on Climate Change (NAPCC). The Government of India has officially accepted WISE's findings for inclusion in the five-year plan targets.
- Developing state-level action plans for climate mitigation through accelerated deployment of clean energy technologies in many Indian states.
- Engaging in developing state-level RE policies and capacity building for state RE development agencies.
- Communication and outreach activities to propagate the need for renewables.
- Research initiatives to prove the long-term viability of renewables.
- Training more than 4000 personnel in various areas of RE development.
- Providing consultancy to RE manufacturers, developers and governments.

WISE comprises different specialist centres. They include:

- Centre for Wind Power
- Centre for Solar Energy
- Centre for Renewable Regulation and Policy
- Centre for Climate & Sustainability Policy
- Centre for Administration & Finance
- Centre for Communications & Coordination
- Centre for Training & Conferences
- WISE Press

The different Centres in WISE work together in the true tradition of inter-disciplinary learning, team spirit, and knowledge sharing. WISE is the pioneering institution in India to possess such all-round expertise most essential to propel the country towards sustainability in the 21st century.

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