Report on

Transitioning to a Cleaner Electricity System Using Conventional Sources as Bridge Fuels – A Systems Study

Prepared by

WORLD INSTITUTE OF SUSTAINABLE ENERGY

World Institute of Sustainable Energy

Supported by

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Abbreviations

AHEC	Alternate Hydro Energy Centre
APM	Administered Pricing Mechanism
ASU	Air Separation Unit
A-USC	Advance Ultra Supercritical
BFBC	Bubbling Fluidised Bed Combustion
BTG	Boiler Turbine Generator
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEA	Central Electricity Authority
CFB	Circulating Fluidized Bed
CFBC	Circulating Fluidized Bed Combustion
CGD	City Gas Distribution
CHP	Combined Heat and Power
CIL	Coal India Limited
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COPD	Chronic Obstructive Pulmonary Disease
CRIP	Controlled Retractive Injection Point
CUF	Capacity Utilization Factor
DPR	Detailed Project Report
E&M	Equipment and Machinery
EIA	Environmental Impact Assessment
EPRI	Electric Power Research Institute
ESP	Electro Static Precipitator
FB	Fluidized Bed
FBC	Fluidized Bed Combustion
FE	Foreign Exchange
FOB	Freight on Board
FSAS	Frequency Support Ancillary Services
GCV	Gross Calorific Value
GHG	Green House Gas
GT	Gas Turbine
HA	Hectare
HEP	Hydro Electric Power
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IIT	India Institute of Technology
IPCC	Intergovernmental Panel for Climate Change
IPI	Iran-Pakistan-India
IRENA	International Renewable Energy Agency
JCC	Japanese Crude Cocktail
K Cal	Kilo Calories
KG	Krishna Godavari
kWh	Kilo Watt Hour
L/H	Length to Head
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
LVW	Linked Vertical Well
MGR	Merry Go Round
MMBTU	Million Metric British Thermal Unit
MMSCMD	Million Metric Standard Cubic Meter Per Day
MoEF	Ministry of Environment and Forests
MoU	Memorandum of Understanding
MPa	Mega Pascal
MTPA	Million Tonnes Per Annum
MW	Mega Watt
MWe	Mega Watts – electric
MWh	Mega Watts hour
NAPCC	National Action Plan on Climate Change
NHPC	National Hydel Power Corporation
NOx	Oxides of Nitrogen
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation
OPEX	Operating Expenditure
O&M	Operation and Maintenance
PC	Pulverised Coal
PF	Pulverised Fuel
PFBC	Pressurised Fluidized Bed Combustion
PLF	Plant Load Factor
PSP	Pumped Storage Plant
PSS	Pumped Storage Station
RE	Renewable Energy
R&D	Research and Development
R&R	Rehabilitation and Resettlement
RM&LE	Renovation, Modernization & Life Extension
RoR	Run-of-River
SIA	Social Impact Assessment
SOx	Oxides of Sulphur
SPM	Suspended Particulate Matter
SSEF	Shakti Sustainable Energy Foundation
TA	Technology Assessment
TAPI	Turkmenistan-Afghanistan-Pakistan-India
TPA	Tonnes Per Annum
TPH	Tonnes Per Hour
UCG	Underground Coal Gasification
USA	United States of America
USC	Ultra Super Critical
VOCs	Volatile Organic Compounds
WB	World Bank
WCD	World Commission on Dams
WISE	World Institute of Sustainable Energy

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Executive Summary

In India, coal-based power has remained the mainstay of the overall electricity generation mix. Large-hydro capacity addition to the mix has been more or less stagnant on account of many factors. Today, significant gas-based capacity and prospective capacity additions face an uncertain future because of the unavailability of gas. Given this background and assuming a business-as-usual scenario, coal will continue to anchor the generation mix.

However, a recently commissioned study by WISE, titled "Future of coal-based electricity in India", suggests that many factors have the potential to hinder the business-as-usual development of coal-based thermal projects in the long term. These factors include the following: risks in securitizing external fuel supplies, macroeconomic constraints such as high current account deficit, externalities of coal-based generation, international pressures relating to climate mitigation and constraints on water availability for thermal cooling.

While we continue to develop coal based projects in the medium terms, given the various constraints, alternatives such as renewable energy (RE) will have to assume an increasingly larger share in India's electricity mix in the future. This realization is already implicit in the National Action Plan on Climate Change, which envisages 15% RE penetration by 2020. In addition, regulatory provisions that accord a must-run status for RE are also in place.

However, large-scale RE absorption into the grid in the short and medium term may be a challenge on account of grid integration issues and, more important, the inadequacy of flexible generation sources to balance the variable RE generation. With this background, a fresh future-oriented interdisciplinary perspective needs to be developed to identify and prioritize conventional technologies based on their ability to provide generation flexibility to support RE in the future grid.

Ideally, these conventional technologies should not only be able to smoothly complement the variable RE by providing generation flexibility but also prove to be better all-round choices considering other non-technology aspects like climate, the environment, society, and institutional risks. Currently, there is not a single document or study that takes a comprehensive systems-level view of conventional generation technologies and related technology and policy choices aimed at the long term.

The present study is strategically aimed at providing this missing link in the current policy discourse. Technically, the 'boundary' of technology coverage is from resource-use (resource extraction, resource transformation/transport and processing) to final generation at the generator busbar. The core technology evaluation and prioritization exercises have been done assuming *no resource or other constraints*. However, these constraints are factored in the subsequent stages to assess short- and medium-term implementation challenges.

Study Methodology

The original scope of the project encompassed all major coal-based, gas-based, and hydro-based resources and main- and sub-technology configurations. The resource categorization included international coal, domestic coal, liquefied natural gas (LNG), and domestic gas. This categorization results in 57 resource / sub-technology / technology combinations in all. A detailed assessment of each would be a wasteful undertaking considering that many may not be suitable or desirable for the present study and even from a broader perspective of technological and strategic suitability. To identify and focus on key technology choices, some technologies or sub-technologies are screened out based on logical considerations. Therefore, the study mainly evaluates 16 resource-technology-sub-technology combinations (Table A).

Table **A** Technologies considered for analysis

Resource	Main Technology	sub-technology
Domestic coal International coal	Supercritical	Pulverized coal Circulating FBC
Domestic coal International coal	Ultra super critical	Pulverized coal
Domestic coal International coal	IGCC	
Domestic coal	UCG with combined cycle	
Domestic gas LNG	OCGT	
Domestic gas LNG	CCGT	
-	Run-of-the-river hydro Storage type hydro	Pumped storage hydro

The study methodology assesses these technologies on a range of parameters – climate, environment, society, economy, technology, energy security risks, infrastructure, and generation flexibility – to develop a comprehensive technology assessment framework for comparing technologies and deriving technology priorities that meet the objectives of this set of diverse considerations.

However, actual technology priorities are derived from two perspectives. The first order of technology priorities is derived after considering technology impacts (climate, environment, society, economy) and implications (technology desirability, energy security risks, infrastructure needs) but without considering generation flexibility. This first order of technology priority is then re-assessed from the perspective of generation flexibility to derive the priority for transition technologies. The main reason for considering generation flexibility separately is to ensure that its effect is explicitly captured in the final order of technology priorities. Figure A shows this methodology.

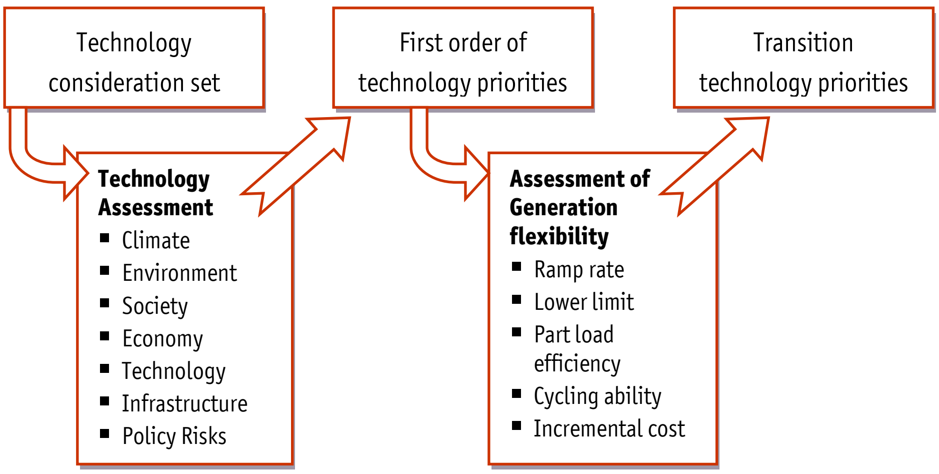

Figure **A** Study methodology

To elaborate, the derivation of the first order of technology priority uses a matrix structure combined with a new quantification tool where the technologies are evaluated across various sub-attributes such as GHG emissions (climate impacts); pollution, land use, biodiversity loss (environmental impacts); public health, employment generation, displacement and rehabilitation, etc. (societal impacts); cost of electricity, CAPEX, OPEX (economic impacts); technology maturity, net efficiency, fuel flexibility, (technology performance implications); energy security risks, macroeconomic risks (policy risks implications), and infrastructure needs (infrastructure implications). *As the evaluative sub-attributes are multidimensional (a mix of qualitative and quantitative information), weights are assigned to them to reflect their relative importance.*

Based on the quantification tool, all the technologies are assigned preference scores across each sub-attribute using a paired comparison table with a preference scale. The preference scores of each technology across each evaluative sub-attribute are then combined with that sub-attribute's weighting to arrive at the final technology scores and thereby at the first order of technology priorities.

In the next step, the list of the first order of priorities is 'loaded' with the generation flexibility attribute. The key sub-attributes considered under generation flexibility are ramp rate, part load efficiency, cycling ability, lowest limit of technical operation, and incremental cost of ramping. The results from this loading form the second order of technology priorities, namely the transition technology priorities.

The importance of the transition technology priorities cannot be emphasized enough. These priorities represent technologies that are not only more sustainable from an overall perspective but also flexible in terms of their ability to support the system as baseload or peak load plants and, more important, as discrete or dedicated balancing load for RE.

The study findings

On a broad level, the study findings suggest the highest priority for hydro technologies, followed by gas technologies. Coal technologies appear to have the lowest priority. Table B shows the order of priorities for the transition technologies.

Table **B** Transition technology priorities

Transition technology priorities (with generation flexibility)			
Rank	**Technology**	**Rank**	**Technology**
1	Run-of-the-river hydro (Pondage)	9	CFBC supercritical (domestic coal)
2	Storage based hydro	10	PC supercritical (domestic coal)
3	Pumped hydro	11	CFBC supercritical (imported coal)
4	CCGT (Domestic gas)	12	PC supercritical (imported coal)
5	OCGT (Domestic gas)	13	PC ultra supercritical (domestic coal)
6	Underground coal gasification (UCG)	14	PC ultra supercritical (imported coal)
7	CCGT(imported gas)	15	IGCC (imported coal)
8	OCGT (imported gas)	16	IGCC (domestic coal)

However, it has to be noted that the transition technology priorities essentially represent technologies from a desirability perspective. In reality, past slippages in hydro and gas technologies and lowering of the share of hydro and gas in future planning (13th plan capacity addition targets cap hydro at 12% and gas at 1.75% in the base-case scenario) suggest that if we factor in resource and implementation constraints, the actual implementable choices would essentially reflect the current planning priorities, which seem to be centred on coal.

In effect, the chasm between our current generation choices and the desirable technologies is a result of the challenges that face the power sector today (rehabilitation and resettlement (R&R) issues, environmental clearance, contractual delays, etc.). Surmounting these challenges would require a different paradigm for technology evaluation, project appraisal, and capacity planning that goes beyond mere cost comparisons and unlocks the significant values (non-monetized values) associated with each of these choices.

To elaborate, from a desirability perspective, the difference between transition choices and implementation choices is not merely of rank but of an order of magnitude. To acknowledge and factor in this difference would require nothing less than redefining 'cost' and 'value' for the key impacts (climate, environment, and society) and implications (energy security risks, macroeconomic risks) that are acknowledged but not 'counted' in our current decision-making process.

These findings and other findings derived from the study methodology and from the interim analysis offer some pertinent insights. These insights form the policy themes identified in the study. The possible action items emanating from these themes form the basis of the recommendations. Some of the key themes and recommendations are given below.

Themes and the way forward

Theme 1: The need to migrate from a cost-centric paradigm to a value-centric paradigm based on public benefit: cost analysis

Technology and project evaluations are mainly based on techno-economic considerations which neither capture the climate, societal, or environmental impacts nor consider the risks related to energy security. Techno-economic considerations are cost-centric in the sense that they consider the cost of electricity as the key decision criterion.

While there is no denying the criticality and the importance of the 'delivered cost of electricity' for India, a relook perhaps at what constitutes the estimation of this 'delivered cost' is very much in order. For public policymaking, 'costs' should ideally represent the value of public benefits vs losses, where the public pays only for the surplus benefits.

In the absence of a rigorous public benefit/loss monetization methodology, the only way to 'value' choices is to weigh all the identified public benefits/losses, including costs.

In this context, there are very important insights that can be drawn from the current exercise which weighs all identified public benefits/losses to derive 'value'-based priorities. Interestingly, the weighting-based exercise also suggests that when a universal consideration set is presented, the 'cost of electricity' is considered on par with other qualitative considerations and the importance of 'costs' becomes relative rather than absolute. This insight has to be acknowledged and incorporated into the current planning psyche.

Recommendations

Project evaluation based on techno-economics discounts project impacts and other qualitative considerations that may be critical from the perspective of long-term policy. Ideally, these qualitative measures have to be a part of project evaluation but cognitive limitations prevent us from making objective decisions from subjective comparisons.

One practical way to widen the project evaluation framework is to assign costs to the key qualitative measures under consideration. For a regulated electricity sector, such a framework has to be based on a public benefit: cost analysis, which would tell us whether the sum total of public benefits exceeds the sum total of public costs—the only public justification for any project or technology.

As a way forward, a more inclusive public benefit-to-cost framework can be created based on inputs received from regulatory commissions, EIAs, SIAs, computations of social cost of carbon as applicable to India, costing of forest lands and loss of forest-based livelihoods, future biodiversity losses, public subsidy costs, and macro-economic costs related to mounting deficits and FE imbalances. Such a framework would, in effect, also help resolve social and environmental issues related to project implementation by allowing diverse stakeholders to speak the same language. This would allow for a more transparent order of priorities in terms of both preferred technologies and projects and foster a healthy debate on societal role and environmental limits.

In this context, the weighting-based framework developed in the study could perhaps be a starting point for a more comprehensive technology and project assessment framework. The weighting-based framework can also serve to highlight the reasons behind conflicting stands against technologies and projects. With the weighting-based framework, policymakers can view technology assessment or project assessment from different perspectives. For example, by giving high weightings to social and economic parameters, one can assess technology priorities from a socio-economic perspective. This kind of flexibility makes it possible to appreciate different point of views and to make the linkages and co-dependencies of decision-making more transparent.

Theme 2: Review of project appraisal and management strategies

The key implementation challenges to power projects range from R&R issues to contractual delays, geological surprises, environmental clearances, etc. In this context, a common refrain against hydro development is the lack of proper due diligence in impact identification and mitigation strategies. A literature review suggests that there are inherent problems with the project development process; for example, institutional commitment to develop hydro projects are made before engaging the affected stakeholders effectively and deciding on 'negotiated' compensation and mitigation strategy. It would seem that the social and environmental impacts of projects are dismissed as collateral damage and it is assumed, without investigating, that public benefits of electricity generation are more than public losses. This assumption may not hold for all hydro projects, and unless each project is actually assessed for these parameters individually, the current implementation challenges would never recede.

Similarly, contractual delays and cost overruns in coal and hydro based projects have been a result of lax contracting clauses and ineffective project management, and unless the focus shifts from 'costs' and 'procedures' to 'quality' and 'competence', any headway in surmounting these challenges would be difficult.

Recommendations

A long-term strategy to manage projects is to understand best practices in project planning and management. For example, in the case of hydro projects, the methodology developed by the World Commission on Dams (*Dams and Development: a new framework for decision making*), suitably adapted to meet specific challenges, could be a very good starting point. The methodology should provide for conducting neutral and impartial Environmental Impact Assessment (EIA) and Social Impact Assessment (SIA) for projects from certifying agencies and special institutions that are regarded as neutral. These institutions can be compensated through an autonomous trust fund, which can be funded by the government and private developers. The same trust fund could also be empowered to obtain bank guarantees from project developers to complete pre- and post-commissioning social and ecological restoration. Another strategy to ensure increased social and environmental due diligence is to include environmental and social sustainability parameters in the lending guidelines of commercial lenders. Although many international banks and multilaterals have guidelines - that mandate compliance with social and environmental sustainability before disbursement, such guidelines are more an exception than a norm. Inclusion of such norms in regulatory standards for commercial banks (Basel standards) could go a long way in ensuring better environmental and social due diligence.

Substantial scope for improvements exists in project management strategies including the tendering process, vendor identification, vendor qualification, contract negotiations, contract management, and project financial management. In this context, the first change could be to move from a 'cost-based selection' to a 'cost-, competence-, and quality-based selection' in line with the practices in the private sector.

For short to medium term, flexible project support mechanisms can be designed to overcome the likely implementation challenges in new projects. One way to use flexible support mechanisms is to restructure such projects by assigning each project a virtual capital credit (assigned as high or low) across parameters like technology, costs, climate, environment, and society. For example, in case of hydro projects stranded solely for environmental and social opposition, the virtual capital credit for society and environment can be considered low while the technology, costs, and climate credits can be considered high. Restructuring the project would, in this case, would mean a trade-off involving the transfer of capital credit from the high-credit parameters 'technology', 'costs', and 'climate' to the low-credit parameters 'society' and 'environment'.

In simple terms, a trade-off between technology credits and society and environment credits could involve measures like reduction in project capacity (designed head, flow, infrastructure), technology changes (cross-flow turbines to match high flow variability, fish-friendly turbines, etc.). Similarly trade-off between 'costs' and 'society' and 'environment' could involve enhanced compensation, increased provisions for minimizing ecological damage, maximization of ecological restoration benefits, etc. Transfers from 'climate' credits could mean additional monetary or fiscal benefits related to avoided carbon costs, which will have to be stipulated.

Irrespective of the actual mechanisms used, the key strategy under the project support mechanism has to be flexibility in project structuring in terms of not only technology configurations but also project costs and compensation packages. This would require revising DPRs and resubmitting them for local and central acceptance. This would take time but would nevertheless be faster than the current system.

Theme 3: Dovetailing short-term technology choices with long-term policy concerns

Caution has to be exercised that short-term exigencies do not result in suboptimal technology choices that cannot meet the future requirements of the grid in terms of operational flexibility, reliability, low cost, and response times as well as a range of environmental, social, and climate concerns.

For example, as estimated by WISE, peaking of coal may happen as early as 2032. By then, the current fleet of new greenfield plants would not have completed even half of their service lifetime. Even if the coal peaking occurs later, as is believed, the idea of coal as a limited resource cannot be ignored. Growing resource nationalism among coal-exporting countries suggests a clear realization that fossil fuel sources are essentially limited and increased exports compromise national energy security in the long run. Recent measures adopted by some coal-exporting countries on curtailing extraction and exports and increasing export prices indicate future constraints in coal markets.

With this background, it is imperative that long-term policy objectives be defined and reconciled with short-term choices. For example, if energy security and low-carbon electricity are expected to be key long-term policy objectives, domestic coal- or gas-based capacities will have to be given precedence over imported coal- or gas-based capacities and cleaner coal technologies (IGCC or UCG) over ultra supercritical in the short term.

More important, a critical assessment of long-term policy objectives and concerns will also provide crucial inputs into near-term policy planning related to technology management (R&D, indigenization, technology transfer, etc.), resource planning (domestic resource development, long term resource-import contracts), etc.

All this would suggest developing a clear vision of future policy objectives and dovetail it with short- and medium-term planning for resource, technology management, and limited deployment plans. Some of the key themes that need to be considered in long-term policy planning and short-term support strategies are described below.

Recommendations

The current process of planning power sector capacity has to go beyond merely assessing capacity addition to identifying and prioritizing desirable technologies to support that capacity addition. The process has to recognize that high-priority technologies have special merits and should be given special preferences.

Specifically, technologies that are considered more desirable (or are estimated to have higher public benefits) should be given greater support to facilitate their timely deployment and added provision should be made for project support mechanisms that alter project structuring to optimize the benefits/losses ratio. Such support could include concessions (waivers on taxes or duties), project facilitation (increased provision for capitalization, enhanced R&R provisions, single-window clearance, easier procedures to transfer land or water rights), and financial or commercial sops (preferential tariffs, subsidies, demand assurance, etc.). For example, specialized support to hydro technologies could involve provisions for a larger R&R package in addition to subsidies and a preferential tariff instead of a cost-plus tariff. While such an approach would seem to go against established practices, the scale of advantages (technological, commercial, energy security, climate, and pollution) and service capabilities (flexible generation) that hydro offers over a 40-year lifetime are greater than those offered by any other technology.

With this background, if we are to consider the future advantage of these technologies over the current implementation technologies, the first step would be to declare a clear technology preference and define capacity targets. Such a declaration will have to be followed up with a detailed technology policy that will stipulate special policy and regulatory provisions to support technology incubation, manufacturing, and deployment. This will have to be supported with a detailed technology management plan to facilitate processes related to technology licensing, resource access, indigenization, manufacturing augmentation, and cost management.

Theme 4: Policy cognizance of the importance of generation flexibility in the future grid

Constrained availability of coal and gas had led to greater penetration of the variable renewable energy, which has to be compensated for through balancing mechanisms on the supply and demand sides. The principal mechanism on the supply side is building flexibility into conventional generation sources. While current operational and commercial mechanisms do not envisage such a role for conventional technologies, such a transformation is perhaps the only solution in medium term until more reliable forecasting of RE and large-scale storage solutions become viable.

The importance of such generation flexibility cannot be overemphasized, which would not only allow optimum use of resources (that would switch from part-load and low-fuel operations under high RE conditions to full-load operation under low RE conditions and vice versa) but also provide additional economic opportunities to conventional technologies. Understandably, the commercial and technical implications and the accompanying regulatory measures of such a strategy will have to be discussed and weighed.

A detailed assessment of coal-based generation technologies (Annexe 1) suggests that they can provide moderate to low generation flexibility with comparatively high part-load efficiencies, which could be valuable in supporting renewables. This realization suggests that just as there is a heat value for coal that is burnt, there is also a 'system value' for coal that is not burnt in operating plants; this unburnt or unused coal is actually a natural energy storage option. However, such a perspective in operational planning is clearly lacking as coal-based technologies are discouraged from participating as flexible sources, and generators that respond to dynamic balancing requirements of the system are not compensated or rewarded. This needs to change.

Recommendations

One way to support generation flexibility in operation is to consider a stipulated balancing capacity window of conventional power technologies as storage and treat it as a system storage option rather than as a firm dispatch source. Although this would necessitate separate regulatory norms for storage, it can also effectively allow generation capacities to provide frequency support ancillary services (FSAS). In this context, developing ancillary services markets or creating a new regulatory framework specifically for incentivizing balancing functions could go a long way in supporting variable RE in high-generation seasons.

However, any such regulatory provision will also have to factor in the costs associated with efficiency loss and cycling for intermittent part-load operation of conventional generation technologies. Policy-level support for facilitating flexible operation could involve higher depreciation benefits, tax incentives, exemption from duty, larger compensation packages to operators, subsidy for upgrading system automation, etc.

Theme 5: Developing a comprehensive technology management policy

Power sector depends a great deal on technology, with almost all generation technologies dependant on foreign OEMs. Past efforts at indigenization have not been very encouraging. Lack of core technology research, R&D professionals, R&D funds, and infrastructure is a serious obstacle to effective technology research and indigenization. Technology patent protection laws in India have also hindered technology trade and transfer processes in some cases.

These aspects need to be addressed by developing a comprehensive technology management strategy that looks at diverse techno-commercial-legal aspects related to technology transfer, technology licensing, patent law protection, R&D funding priorities, manufacturing policy, commercial exposure, capacity building, O&M and spares support, performance guarantees and penalties, capacity development, etc.

Recommendations

One way to manage such an interdisciplinary activity is to create an autonomous body comprising specialists with technology management experience, drawn from the industry, academia, and research institutions. Some of the specific functions that such a body can be expected to perform include the following: conduct independent reviews of technologies; facilitate bilateral R&D collaboration opportunities (for control components and technologies); assess raw material requirements and suggest strategies for securing raw material supplies; identify technology customization requirements; identify capacity building needs; facilitate technology transfer or technology import agreements; and advise the Government of India on a detailed technology adoption plan covering independent technology impact assessment, activity lists for adoption with priorities and responsibilities, training and personnel needs, budgetary support across the activities, and a time frame for implementation

Understandably, an organization entrusted with these duties will need highly skilled and technical professionals and these professionals would come at a cost. These costs could be met through parallel contributions from industry bodies, technology providers, OEMs, bilateral funding agencies, and the Government of India, though which all the contributions will be routed. An autonomous status for such a body is essential to ensure that it works without any influence and is able to build credibility as an independent think tank.

Theme 6: Transition technologies: a new perspective

Some of the technologies that emerge as good transition choices need to be considered for special policy focus considering their specific advantages and characteristics.

Circulating fluidized Bed combustion technology (CFBC): fuel flexibility for energy securitization

Fuel flexibility means the ability of a technology to accept fuels of variable quality. For the technologies under consideration, fuel flexibility refers mainly to the ability of CFBC boilers to accept a wide range of fuels.

One of the major differentiating features of a fluidized bed (FB) boiler is its ability to burn a variety of fuels without any major effect on performance provided the fuel handling systems are designed to meet this flexibility in the feed. In comparison, a PC boiler can be operated only on the fuel for which it is designed. CFBC boilers also provide significant environmental benefits because of their low NOx emissions and their amenability to SOx capture through sorbent absorption. These advantages need to be recognized and considered in technology selection.

Recommendations

The ability to handle fuels of variable quality makes CFBC units an attractive technology. CFBC boilers can handle high-grade coals as well as low-grade and even lignite. Lower NOx and SOx emissions are other advantages of CFBC boilers. However, CFBC boilers for supercritical units are still new (only one CFBC supercritical plant is in operation worldwide) and only a few foreign OEMs have capacity to develop large-scale CFBC units. However, the strategic advantages in providing energy security should outweigh the considerations of technology access and spur its early adoption in India.

The first step to support this technology is to declare CFBC supercritical as a preferred technology and plan an early pilot study. In parallel, a comprehensive technology management plan should be developed that integrates diverse aspects related to R&D, system engineering, technology evaluation, technology indigenization, component availability and costs, technology transfer, and patent laws to ensure early commercialization of the technology.

Pumped hydro storage as system asset

Pumped hydro emerges as a very good transition technology from the technology assessment framework. Technically, it can provide excellent load-following capability, large-scale storage, and ideal grid management services. However, major issues with pumped hydro seem to be related to its commercial feasibility considering the high capital costs and net energy loss. A built capacity will have to recover its investment costs in addition to its operating costs (normal O&M costs as well as the pumping costs), and the final delivered cost of energy may be high. Another issue is the location specificity of pumped hydro.

However, despite these issues, pumped hydro storage can yet make sense for utilities as well as renewable energy suppliers if it is considered a system asset rather than a commercial asset. Using pumped hydro as a balancing asset when solar power is abundant is technically feasible and may also prove commercially viable under certain conditions. Pumped hydro systems can also provide ideal Frequency Support Ancillary Services (FSAS) and work as the first-level response before conventional generation technologies.

Recommendations

One of the most effective ways to develop pumped storage hydro is to use the existing medium-size irrigation dams for establishing greenfield pumped hydro projects. Recent experiments with pumped hydro also point out ways in which large pumped storage capacities can be built with underground storage using a piston in a cylindrically excavated tunnel along with a penstock and a pump turbine unit (www.gravitypower.net). All this suggests pumped hydro as a technically and commercially viable technology for India.

From a regulatory perspective, pumped hydro power can also provide first level of FSAS in the proposed ancillary services market. Another possibility is to pair pumped hydro capacity of a particular project, partly or fully, with a renewable generation management centre, which, in turn, would be allowed to use the allocated storage capacity to maximize its revenue potential by selling the hydro generation in open market. In turn, the utility could get either a share of the trade surplus or a waiver based on negotiated generation set off.

Underground coal gasification: the cleanest coal technology

Underground coal gasification emerges as the best coal-based transition technology considering its relatively benign climate, environmental, and social impacts, moderate costs, and greater energy security benefits. Availability of suitable sites and technology access can make UCG a preferred choice even in economic and performance terms. Additionally, UCG can work best with high-ash Indian coal and can utilize the coal available in seams that are not considered feasible for commercial extraction. Although international experience with pilot projects suggests risks of water contamination and land subsidence, the other benefits could outweigh these considerations especially if sites are selected judiciously.

Recommendations

The immediate policy priority is to identify possible sites, estimate their resources, and follow up with detailed geological and geotechnical investigations to limit their proximity to water bodies (to eliminate water contamination) and to assess the strength of the underlying rock strata (to rule out land subsidence). Considering the nascency of this technology in India, appropriate technology assessment will have to be carried out and technology partnerships forged for resource assessment and site selection. Efforts on R&D and investments in pilot studies should ideally begin only after a thorough assessment of resources and sites.

In addition to the overarching themes, some key observations and recommendations on other conventional generation technologies covered in the study relate to their technical feasibility and technology support needs. *Supercritical PC*-based technology seems to be the most dependable technology in the short to medium term. However, as most of the supercritical units currently operating in India are designed for high-GCV imported coal or blended coal, their performance on the low-GCV, high-ash domestic coal should be critically evaluated since it has implications for long-term dependence. The focus of technology support for this technology could be on assessing design customization needs and indigenization opportunities. *Ultra supercritical* PC technology has not been modelled yet for low-GCV domestic coal and has complex metallurgical requirements. The key factors that need to be considered before adopting this technology relate to boiler customization (for burning domestic coal), technology and metallurgy costs, operational reliability, and breakdowns due to the failure of complex metallurgical interfaces. It would be advisable to review these considerations for five years before making any policy preferences. *Integrated gasification and combined cycle (IGCC)*, based on the entrained-flow-gasifier technology, although mature and available, may not be suitable for the low-grade Indian coal. On the other hand, IGCC with fluidized bed gasifier technology, which can handle wider variations in fuel quality, is not available as large units. The best strategy for IGCC could be to support R&D on developing large-capacity fluidized bed gasifiers. The mature, entrained-flow-gasifier technology may have to be reviewed for operational reliability, mainly for operation with Indian coal, before being adopted for large-scale implementation. The cost trajectory of IGCC will also have to be closely monitored to assess feasibility. *Carbon capture and storage (CCS)* may not be a viable option for India considering that the only feasible geological locations for carbon storage are in the north-east, implying the need for costly transport infrastructure from generation centres in the hinterland. However, the most important consideration is that not a single CCS project is operational so far anywhere in the world. It would be advisable to clearly understand the technological challenges by analysing operational data before making any effort to assess its feasibility for India.

Overall, the study findings suggest that a wide chasm separates the technology choices that we desire from those that we have to make. Over time, this chasm is expected to widen. In a real sense, the constraints prohibiting us from exercising a choice are related to our current systems of evaluation and our insistence on adhering to them. It is, however, clear that a business-as-usual approach will be unsustainable in the long run. The only option for us is to change our systems and redesign them for the future.

The current technology assessment framework developed in this study is one attempt at such redesign. This framework, or any alternative framework that can capture the 'value' of choices and preferences impartially, could go a long way in facilitating more informed decision-making.

CHAPTER 1

BACKGROUND AND INTRODUCTION

1

BACKGROUND AND INTRODUCTION

Historically, coal-based generation has dominated the power generation mix in India as large-hydro stagnates and significant gas-based capacities are stranded for want of gas. A recently commissioned study by WISE, titled "Future of coal-based electricity in India", revealed that many factors are likely to hinder the business-as-usual development of coal-based thermal projects in the long term. These factors include the following: risks in securitizing external fuel supplies, macroeconomic constraints like energy security, balance of payments (high current account deficit), externalities of coal-based generation, international pressures relating to climate mitigation, and constraints on the availability of water for thermal cooling.

Given the above constraints, it appears that renewable energy will have to assume an increasingly larger share in India's electricity mix in the future. This realization is already implicit in the National Action Plan on Climate Change (NAPCC), which envisages 15% RE penetration by 2020. In addition, regulatory provisions that accord a must-run status for RE are also in place.

However, large-scale RE absorption into the grid in the short and medium term may be a challenge on account of grid integration issues and, more importantly, the unavailability of flexible conventional generation sources to balance variable RE generation. Against this background, a fresh, future-oriented interdisciplinary perspective needs to be developed to identify and prioritize conventional technologies based on their ability to provide generation flexibility to support RE in the future grid.

Ideally, these conventional technologies should not only complement variable RE (generation flexibility) smoothly but also be better all-round choices considering other non-technology aspects like institutional (policy and regulation), economic, social, environmental, and climate impacts. This in turn would mean an interdisciplinary technology assessment exercise that can help in choosing the best suite of conventional technologies in the short, medium, and long run.

In particular, this will apply to coal-based generation technologies as these are currently the largest contributors to the grid and are also considered inflexible. Hydro- and gas-based technologies, although flexible, need to be investigated with respect to non-technology aspects. Within this context, the present study will apply its evaluation framework to all existing conventional generation technologies like coal, hydro, and gas with respect to both technological and non-technological aspects. Currently, not a single document or study has taken a comprehensive systems-level analytical view of the transitional role for conventional generation technologies and the related technology and policy choices aimed at the long term.

This study will be strategically aimed at this missing link in the current policy discourse. The study is expected to provide a systems-level view of the transitional role for fossil fuels and hydro in power generation. Such a view is difficult to uphold publicly without working out the long-term options, feasibility, and policy implications of the transitional technologies. The policy issues could range from preferential support to flexible technologies through priority for inclusion in the planning process and support for technology procurement (since such technologies meet multiple policy objectives) to incorporation into the 13th Five-Year Plan targets and so on.

Objective of the study

Given the above context, the objective of this study is as follows: "To conduct a critical assessment of conventional generation technologies (coal, gas and hydro) that will indicate the most suitable technology options from policy, business and societal perspectives for aiding a transition to renewable energy (RE) and prevent technology lock-in, without economic or environmental instability."

It is the essence of this study to identify efficient conventional technologies possessing operational flexibility (generation flexibility) compatible with future electricity grid so as to allow absorption of larger proportion of clean, RE-based electricity.

Study Approach

The present study proposes to use a systems approach in contextualizing the "technology choice" problem. In the context of the study, the term 'system' is used to indicate a hierarchy of physical systems with climate as an all-encompassing set and technology as a fourth order subset (Figure 1).

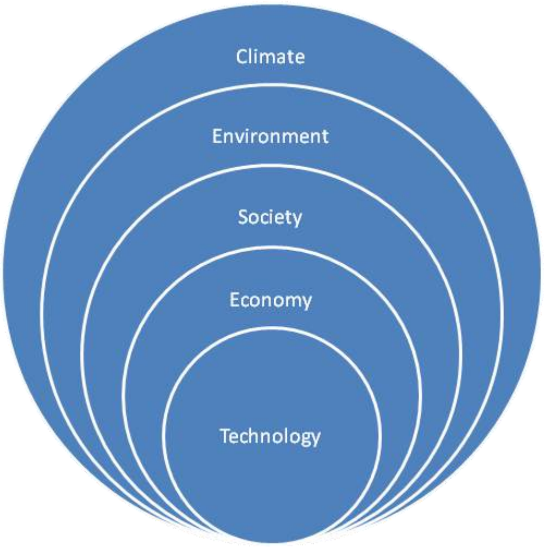

Figure **1** Description of the system used in the study

The scope of the study involves assessing existing and emerging conventional technologies across diverse evaluative parameters. The core technology evaluation and prioritization exercise is done assuming no resource constraints. However, resource constraints are factored in the subsequent stages to identify short-term and long-term technology priorities. Technically, the 'boundary' of technology coverage is from resource use (resource extraction, resource transformation/transport, and processing) to final generation at the generator bus bar.

Further, as technology (for example, IGCC and CCS) and resource evolution (for example, shale gas or shale oil) are dynamic, the outputs of the present study are deemed to be relevant only in the short to medium term, the clear implication being that the same study methodology would give a different output in a changed technology and resource availability scenario. **Therefore it is proposed to thoroughly review the study using the same methodological tools after 5–10 years.**

The study relies extensively on the inputs and expertise of a specially constituted 13-member inter-disciplinary expert group representing eminent experts from various fields like policy, regulation, environment, economics, technology, and power systems. The core project team involves senior officials from WISE and two independent consultants with over 60+ years of diverse industry experience between them: one senior consultant, with experience of over 27 years, has provided inputs on technology assessment and technology analysis of key conventional technologies. The other senior consultant, with over 37 years of core Industry experience, has mainly provided inputs on future gas resource availability and its impact on the power sector.

Overview of the Study Methodology

On a broad level, the methodology of the study can be converted into five interlinked parts.

STEP 1: TECHNOLOGY SELECTION AND SCREENING

The original project scope involved all known coal-based, gas-based, and hydro-based resources and main- and sub-technology configurations. The resource categorization included international coal, domestic coal, liquefied natural gas (LNG), and domestic gas. The main technologies were as follows. Coal-based: subcritical, supercritical, ultra supercritical (USC), advanced USC, integrated gasification combined cycle (IGCC), and underground coal gasification; gas-based: open cycle and closed combined cycle gas turbines (OCGT and CCGT); hydro-based: reservoir and run of the river (RoR). The sub-technologies considered were pulverized coal (PC), fluidized bed combustion (P/B/C FBC), combined heat and power (CHP), carbon capture and storage (CCS), renovation, modernization and life extension (R&M and LE of sub-critical), and pumped hydro storage (PHS).

Based on original categorization, there are a total of 67 resource / sub-technology / technology combinations. The main methodological intervention in this module is the screening out of some technologies/ sub-technologies based on logical considerations.

STEP 2: IDENTIFICATION OF TECHNOLOGY EVALUATION ATTRIBUTES

Prioritizing technology choices would require us to first understand the key evaluative attributes against which all technologies should be assessed. In line with standard TA studies, technologies are assessed in terms of their impacts on **climate**, **environment**, **society** and **economy**. In addition to the impacts, specific technology risks in the area of **technology performance**, **infrastructure** needs and **policy risks** are also considered as additional evaluative attributes.

For each of the main evaluative attributes, a comprehensive list of sub-attributes is prepared, out of which, a final list of evaluative sub-attributes are identified based on their relevance and individual standing. All these key evaluative sub-attributes are assigned weightings to reflect their relative importance.

Note: Although generation flexibility is one of the main evaluation criteria, it is not considered at this stage but is considered separately in Step 4. The main reason for doing this is to ensure that the effect of generation flexibility is explicitly captured in the final order of technology priorities

STEP 3: TECHNOLGY ASSESSMENT MATRIX & DERIVATION OF FIRST ORDER OF TECHNOLOGY PRIORITIES

This module derives the first order of technology priorities after comparing technologies across sub-attributes and factoring in sub-attribute level weightings. The standard representation uses a matrix structure with technologies as columns and attributes/sub-attributes as rows.

In the first order prioritization, technology priorities are assessed without considering generation flexibility while considering all other aspects that need to be evaluated. New methodological tools are employed to derive the order of priorities from the matrix using paired comparison table with sub-attribute weights.

STEP 4: LOADING GENERTION FLEXIBILITY AND DERIVING PRIORITIES FOR TRANSITION TECHNOLOGIES

'First order of technology priorities', derived from step 3, is 'loaded' with generation flexibility characteristics to re-prioritize technologies that can play transitional role (by providing generation flexibility). The generation flexibility sub-attributes considered for evaluation include ramp rate, part load efficiency, cycling ability, lowest limit of operation, and incremental cost of ramping.

The technology priorities, derived after loading generation flexibility, are called transition technology priorities.

STEP 5: POLICY IMPLICATIONS, THEMES AND RECOMMENDATIONS

Transition technology priorities are reassessed from the perspective of resource and implementation constraints to understand the gap between desired choices and current implementation choices.

The key insights generated from the project methodology and from the contrast between these choices help derive policy themes and related action points.

Based on the methodology, the project report is structured as follows. Chapter 2 starts with a brief overview of all the major generation technologies and then screens out unviable choices to focus on 'dependable' technologies. Chapter 3 tries to identify the key technology evaluation parameters and goes on to assign weightings to the identified parameters. Chapter 4 covers technology evaluation for each parameter by employing a matrix structure to 'dimensionalize' the technologies and parameters. This chapter also derives the first order of technology priorities using a different quantification approach. Chapter 5 re-prioritizes the first order of priorities by loading generation flexibility to derive a revised order of priorities for transition technologies. Chapter 6 tries to understand current implementation choices and highlights the key constraints that distance transition technology choices from our current implementation choices. Chapter 7 highlights key policy themes and recommendations emerging from the methodology and the study findings. Chapter 8 offers a brief conclusion.

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CHAPTER 2

TECHNOLOGY SELECTION

2

TECHNOLOGY SELECTION

The ambit of technology assessment extends from resource extraction to generation at the generator bus bar. The original scope of technology coverage included all known conventional resources (coal and gas), conventional technologies in coal, gas and hydro and their related sub-technologies, and other relevant strategies. The resource side covers resource extraction, transport, and processing. The focus is essentially on large, utility-scale technologies and not on small-scale generation technologies.

Note: *Nuclear power is however not considered under the original suite of technologies mainly because of lack of sufficient information related to techno-economic parameters and socio-environmental implications.*

Based on this understanding, the original suite of resource – technology or sub-technology combinations is shown in Table 1.

Table **1** Original set of technology choices under consideration

Resource	Main technologies	Main sub-technologies	Other sub-technologies
Domestic coal	Sub critical	Pulverized coal (PC) fluidized bed combustion (PFBC, BFBC) circulating FBC (CFBC)	Carbon capture and storage (CCS)
Domestic coal Intl coal	Supercritical	PC PFBC, BFBC CFBC	CCS
Domestic coal Intl coal	Ultra super critical	PC	CCS
Domestic coal Intl coal	Advanced ultra super critical	PC	CCS
Domestic coal Intl coal	Integrated gasification and combustion cycle (IGCC)	Fluidized bed gasifiers Entrained flow gasifiers	CCS
Domestic coal	Underground coal gasification (UCG)		CCS
Domestic gas LNG	OCGT		CCS
Domestic gas LNG	CCGT		CCS
Domestic coal		RM&LE (subcritical)	CCS
Domestic coal Domestic gas LNG	CHP		CCS
-	Large hydro	Run of the river (with pondage) storage hydro	Pumped hydro

2.1 Brief Overview of resource and technology choices

The following section briefly describes the technology choices categorized in terms of coal-based technologies and gas-based technologies. **This overview is excerpted from a more detailed resource and technology description and assessment study in Annexe 1.**

2.1.1 Coal-based resource and technology choices

Coal is the mainstay of India's power sector and accounts for about 70% of utility power generation. Although coal-fired power plants are reliable and cost effective, they also have climate, environmental, and social impacts. In the context of the study, it is assumed that all imported-coal-based plants use 100% imported coal and are located near the coast. Conversely, it is assumed that all domestic-coal-based plants use 100% domestic coal or blended coal (with at least 70% domestic coal) and are located inland.

2.1.1.1 Coal resources (Annexe 1: pp 1-6)

Coal resource choices for India are limited as domestic coal availability constraints have forced power generators to rely increasingly on imported coal sourced mainly from Indonesia and Australia. There are significant differences in the coal grades and quality between domestic and imported coal; more important, however, are the implications of the choice of coal resources (domestic or international) for technology performance, environment, society, economy, and energy security. This study categorizes coal resources mainly as domestic and imported, as explained below.

- Domestic coal: Majority of Indian coal contains a high percentage of ash (up to 40%) and low to medium percentage of sulfur (0.3%–0.5%) and is in the sub-bituminous quality range. Such high ash-to-carbon loading but relatively low sulfur suggest that domestic coal has more erosive potential than corrosive potential as compared to imported coal. Lignite available in the country usually has high moisture content (up to 55%) and is characterized by medium to high sulfur content but its availability is limited to two regions in India. The Government of India has not envisaged any large-scale additions to lignite-based capacities in the 12th or the 13th Five-Year Plans. Therefore, lignite is not considered here separately.
- Imported coal: Imported coal includes all the available coal grades sourced mainly from Australia, Indonesia, and South Africa. In general, imported coal has lower ash and marginally lower silica content. Although imported coal typically has almost double the sulfur content on mass basis, its high GCV would mean that the sulfur content on a heat value basis will be similar to that of domestic coal. The primary characteristics of domestic and imported coal considered for the study are shown in Table 2.

Table **2** Characteristics of Indian coal and imported coal

Parameter	Indian coal	Imported coal
Gross calorific value (kcal/kg)	3500–4000	5000–6000
Moisture (%)	8.0–20	6.0–12
Ash (%)	35–45	6.0–10
Sulfur (%)	0.3–0.5	0.6–0.8
Volatile content (%)	20–35	25–40

Note of washed coal (Annexe 1: pp 131-132)

Indian coal contains 35%–40% ash, which affects the performance of a plant. Washing such coal reduces its ash content, makes the coal less abrasive, and gives a higher-quality fuel of consistent heat *value. Using washed coal may be expensive, but the economic benefits to the plant are more significant. Washed coal reduces the quantity of fuel required: washing increases its calorific value of coal and is therefore equivalent to increasing the capacity of a mill; reduces auxiliary power consumption, resulting in greater efficiency; lowers capital and operational costs; confers significant environmental benefits it terms of lower GHG emissions; and also reduces the wear and tear of fuel-handling systems, thereby reducing maintenance costs. All these benefits lower the cost of generation and increase annual savings.*

The current MOEF guidelines require all power plants located 1000 km or beyond a pithead to use washed coal. However, it is understood that this stipulated distance is being shortened to 500 km

Although wet washing has been used predominantly, it is only marginally cost-economic partly because the heat gain from washing is partly nullified by the increased moisture content and also because the yield (net mass of washed coal per unit input coal) is inversely proportional to the ash content in the washed coal. Recently, dry washing of coal has caught on and holds much promise. One of the technologies that have been pilot-tested in India is that developed by VirginiaTech (USA) using air.

Considering that less than 25% of the thermal coal is washed at present and water availability is also a constraint, it could be worth looking for economies of scale for dry washing and draw up a suitable road map of adopting that technology.

2.1.1.2 Coal technologies and sub-technologies

Subcritical technology (Annexe 1: pp. 7-8)

Most of India's coal-based capacity uses subcritical technology with typical unit sizes ranging from 130 MW to 600 MW. Subcritical technology's operating pressure is around 170 bar and temperature is in the range of 540–568 °C. Subcritical cycle is characterized by a steam drum acting as the fulcrum of the steam–water circulating system. The feed water, after passing through the regenerative feed water heaters and economizer tubes, enters the steam drum. The water comes down through the down-comers and enters the convective section of the furnace where heat transfer occurs. The water after absorbing heat from the furnace water walls rises by natural gravity (caused by density difference) or is assisted by circulating pumps and enters at the top of the steam drum. Steam is separated from water by a cyclonic separator and the cycle repeats.

Though subcritical units can theoretically operate close to the critical pressure (221 bar), industry experience suggests that operating at pressures above 180 bar gives diminishing returns on the cycle efficiency. Gross efficiency of subcritical plants in India is 35%–37% and typical net efficiency is 32%–35%. Typical costs for subcritical technology are Rs 55–65 million/MW CAPEX, and Rs 1.5 million/MW/year OPEX, as (fixed) operating expenses.

Subcritical technology is at an advanced stage of maturity in India but is largely considered near-obsolete in advanced countries. Although India has achieved significant expertise in the indigenization of this technology, its inferior performance on all fronts (techno-economics, emissions, etc.) as compared to other coal technologies has brought it into disfavour with the Central Electricity Authority (CEA), which has recommended a phase out of this technology by 2017.

Supercritical technology (Annexe 1: pp. 8-15)

Supercritical technologies are largely seen as the preferred substitute to the subcritical technology. Supercritical units for Indian power stations are typically 660–800 MW. Current supercritical boilers operate around 250 bar, with temperatures ranging between 568 °C and 596 °C. Boiler design is the once-through type without the steam drum. The feed water, after passing through the regenerative feed water heaters and economizer tubes, enters the furnace and gets out of the system as superheated steam. From the furnace outlet, the steam goes through different stages of superheaters (and inter-stage attemperators) and finally exits the boiler.

Since the flow is once-through, there is no recirculation in the evaporator circuit. The once-through flow requires supercritical furnaces to have a different design to operate in a sliding pressure operation mode: in subcritical mode under low loads and in supercritical mode at higher loads.

A significant point is that the metallurgical requirements of supercritical steam cycle equipment are calibrated in line with a progressive increase in temperature (and marginally in pressure). For the base-level technology, there is virtually no change in metallurgy between subcritical and supercritical technologies except for water wall tubes, where alloy steels are preferred to carbon steel used in the subcritical technology. However, operation at the higher end of supercritical temperature range calls for major changes in metallurgy and fabrication (welding, heat treatments, etc.).

The gross efficiency of supercritical plants is approximately 39% and net efficiency is approximately 37%. Typical ranges of CAPEX and OPEX are Rs 55–65 million/MW and Rs 1.5 million/MW/year, respectively, and even lower for higher unit sizes.

The supercritical technology is considered mature worldwide but is a relatively new entrant in India. The first supercritical thermal unit in India was commissioned in 2011. However, the technology seems to be fast maturing as the bulk of new thermal projects under construction or under consideration are of supercritical technology.

Ultra-supercritical technology (Annexe 1: pp. 8-15)

Ultra-supercritical technology is an upgraded version of supercritical units, with operating steam temperatures between 600 °C and 620 °C and typical unit sizes of over 800 MW. Although the operation of ultra-supercritical unit is similar to that of a supercritical unit, there are major metallurgical challenges in working at high temperatures, which require specialized alloys (austenitic stainless steels or duplex steels).

The gross and net efficiencies of USC units are typically around 40% and 38% respectively. However, the higher efficiency comes at a price. Typical CAPEX and OPEX requirements for USC units are Rs 70–75 million/MW and over Rs 1.5 Million/MW/year.

This technology is proven overseas and there are about 60 ultra-supercritical units in operation worldwide. Large unit sizes (up to 1000 MW) are also being developed in advanced economies. However, commercial deployment in India is expected to be delayed.

Advanced ultra-supercritical technology (Annexe 1: pp. 15-19)

As the name implies, advanced ultra-supercritical (A-USC) technology is an advanced version of USC technology with operating temperatures of 700–760 °C and pressures of 300–350 bar. The main performance leapfrogging for this technology is in terms of its expected efficiency, which is over 45%, 10%–12 % higher than even the ultra-supercritical units currently in service.

However, A-USC units are yet in incipient stages of development and there have been setbacks in the development of certain super-alloys required for component development. Large-scale development of A-USC units in India will call for extensive use of highly expensive nickel-based super-alloys. An order-of-magnitude estimate is about 2000 tonnes of super alloys for a typical 800 MW unit. Further, considering the domestic coal quality and chemistry, the size of the boiler and auxiliaries will be far higher than those being developed in advanced countries, which, together, will make an advanced-USC-based thermal power unit far more expensive under Indian conditions.

Steam conditions in the vicinity of 300–350 bar and temperatures of 700–750 °C are expected to take the gross plant efficiency to 45%–47%; however, the net efficiency would be 43%–45%. The expected CPAEX would be Rs 85–105 million/MW while operating costs are expected to be significantly higher than those for supercritical units.

A-USC technology is still far from commercialization even at the global level with IEA suggesting limited possibility of technology commercialization before 2025. The main challenges relate to costs and metallurgy. For India, these challenges do not suggest early adoption of A-USC technology in the near term.

Integrated gasification and combined cycle (Annexe 1: pp. 28-45)

Integrated gasification and combined cycle (IGCC) is an emerging coal-based technology in India and combines two processes: gasification and combustion. In the first stage, coal undergoes partial combustion at a low 'air to fuel' ratio and gets converted into synthesis gas (syngas). In the second stage, syngas is burned in a combined cycle mode of power generation involving gas turbine and a heat recovery steam generator with a steam turbine.

Gasification can be achieved using different technologies, the most common being entrained flow, fluidized bed, and fixed bed gasifiers. IGCC has gained attention because gasification reduces SOx and NOx emissions significantly compared to the reductions achieved by other coal-based technologies. However, one of the main drawbacks of the IGCC is poor reliability; high-ash coals result in erosion, corrosion, fouling, and plugging of high-temperature heat recovery units in addition to problems in gasifiers. Sluggishness of air separation units is another significant aspect, which precludes fast ramp up and down.

Under Indian climatic conditions, the predicted gross efficiency is 47%–50%. However, high auxiliary consumption (16%–22%) may bring down the net efficiency to 37%–40%. More significantly, expected CAPEX could be anywhere between Rs 100–200 million/MW (based on data from some pilot projects). OPEX is expected to be significantly higher than that for ultra supercritical units.

Worldwide, there are only about a dozen operating plants and most of them use high-grade coal. For IGCC technology, there will be significant challenges in gasifying Indian coal in view of its high ash content. However, keeping in view the all-round environmental friendliness of this technology, the Government of India has already taken tentative steps in harnessing this technology with a 180 MW unit under construction in Andhra Pradesh and an additional 1000 MW pet-coke-based IGCC unit being implemented in the private sector.

Underground coal gasification (Annexe 1: pp. 45-49)

Underground coal gasification (UCG) is essentially in situ gasification in underground coal mines by injecting an appropriate oxidant. The process is primarily deployed for coal seams at depths beyond the reach of the cost-economic conventional mining process. The technology involves drilling two parallels wells, an injection well for injecting the oxidant (air, oxygen, or steam) and a production well for capturing the generated syngas. The syngas produced is then burned in the combined cycle mode of generation.

So far, two technologies have been used widely for gasification and extraction: linked vertical well (LVW) and controlled retractable injection point (CRIP). Both rely primarily on two linked boreholes to inject the oxidant and remove the syngas. For large units with deeper coal seams, however, CRIP has emerged as the preferred method.

UCG technologies offer more environmental benefits than traditional coal-based technologies do in terms of lower air emissions, no above-ground coal mining and combustion waste, and less intense surface development. However, experience from other projects suggests that large-scale exploitation of UCG may have other environmental impacts ranging from land subsidence to groundwater contamination.

The gross and net efficiencies of UCG-based combined cycle could be 50%–55% and 49%–54% respectively. The CAPEX of this technology is expected to be largely site specific, mainly dependant on the quality of coal, the depth and thickness of the coal seam, the distance between injection and production wells, and the distance between the cavities. The overall costs of generation, however, could be lower than those for CCGT units firing natural gas.

China is reportedly planning to exploit UCG in a big way with 30-odd projects in the pipeline. A number of UCG projects are being undertaken across continents. Technically, UCG seems a good prospect for India as it is especially suitable for low-grade coals, which shrink while burning, allowing a free passage for the gas to flow. India has already started the process to auction five lignite and two coal blocks (with an aggregate reserve of about 900 million tonnes) for exploiting UCG.

SUB-TECHNOLOGIES FOR COAL-BASED POWER

Pulverized coal

Most coal-fired power plants in operation today use pulverized coal.

Pulverized coal units use a proven technology that can be highly reliable. The furnaces operate at high temperatures (1300–1700 °C). Further, in view of the once-through nature of flue gas flow, the furnaces in pulverized coal technology are taller than those used in other coal technologies. Fuel grain size is below 0.1 mm, and the tolerance of these units to variation in grain size is low.

Fluidized bed combustion (Annexe 1: pp. 19-27)

The combustion process in Fluidized bed technologies operates in suspended condition at a temperature below the melting point of ash, typically 850–900 °C. Unlike pulverized coal boilers, FBC boilers can accept fuels with both extremes of the heating value – from the low-volatile high-GCV anthracite to the low-GCV high-ash- or high-moisture residual-derived fuels – because fuel forms up to 5% of the total bed by volume. The furnace of a fluidized bed boiler contains a mass of granular solids, generally in sizes of 0.1–1.0 mm depending on the type of the fluidized boiler. The fuel size is typically 0.1–8 mm.

Primarily, fluidized bed combustion (FBC) is of three types: pressurized, bubbling, and circulating.

Pressurized fluidized bed combustion (PFBC)

The PFBC design was conceptualized originally as the core of a possible combined-cycle, high-efficiency power generating system. However, its attraction as an economically viable power generation mode tapered off as the firing temperature of gas turbines moved beyond the combustion temperature of the FBC technology and eventually the technology became obsolete.

Bubbling fluidized bed combustion

A bubbling fluidized bed boiler comprises a fluidizing grate through which the primary combustion air passes and a containing vessel made of (lined with) refractory tubes or heat-absorbing tubes. The vessel would generally hold bed materials with or without heat-absorbing tubes buried in it. The open space above this bed, known as freeboard, is enclosed by heat-absorbing tubes. The secondary combustion air is injected into this section. The convective section accommodates the remaining heat transfer surfaces including the air heater. Fuel is fed either from the top or through the bottom of the grate, while the ash generated in the bed is drained from it.

Bubbling bed units were developed as a cost-economic mode of generation for captive power and steam for industrial applications. Typical gross efficiencies are relatively low (25%–27%) in the subcritical steam cycle in view of the low thermodynamic efficiency associated with the steam cycle as well as a higher carbon carry-over through flue gas. Typical unit sizes in BFBC are 10–40 MW with limited scope for developing larger, utility-size units.

Circulating fluidized bed combustion

CFBC technology, originally developed for firing high-sulfur coal for small and medium size applications, has, during the past decade, evolved as an economically viable alternative for even larger units. The main advantages of CFBC boilers is that they can accept fuels with both extremes of the heating value – from the low-volatile high-GCV anthracite to the low-GCV high-ash- or high-moisture residual-derived. Although there are efficiency losses associated with variation in fuel mix, these losses are still small and do not affect operations unlike in the case of PC-based boilers, in which a variation in fuel mix can lead to serious operational issues. In a CFBC boiler furnace, the gas velocity is sufficiently high to blow all the solids out of the furnace. The majority of the solids leaving the furnace are captured by a gas–solid separator and re-circulated to the base of the furnace at a rate sufficiently high to cause minimum vertical mixing of solids in the furnace. A fraction of the combustion heat is absorbed by water- or steam-cooled surfaces located in the furnace, and the rest is absorbed in the convective section located further downstream, known as the back-pass.

Gross efficiency with subcritical operation is typically 33%–36%. Since only a few medium-scale CFBC units have been installed in India so far, the cost of building or operating large-scale CFBC boilers in India cannot be forecast with certainty but is expected to be higher (Rs 60–70 million/MW) than that of PC units (with subcritical) of similar size. Operating costs could be Rs 1.5–2 million/MW/year.

Although CFBC technology is not available for supercritical unit sizes at present, the advantages of using CFBC boilers with supercritical technology are evident and many OEMs are currently implementing large projects and also actively working on the design and commercialization of larger CFBC unit sizes. Foster-Wheeler is working on upgrading CFBC boiler unit sizes to make the technology work in the ultra-supercritical range.

2.1.2 Gas resources and technologies

Gas-based generation technologies are relatively new in India when compared to coal and hydro. Although gas-based technologies are preferable to coal-based technologies from the perspective of climate, the environment, generation flexibility, etc., gas availability in recent years has been the biggest constraint in the development of gas-based capacities with over 50% of the installed capacity currently lying idle. In view of the ongoing conflicts related to gas resource estimates and delivered price, the project team tried to estimate gas availability over short to medium term and, in this context, prepared a detailed report on the prospects for natural gas in India. Although the report is separately attached as **Annexe 2**, the following section tries to highlight the key findings related to the supply of gas.

2.1.2.1 Gas resources (Annexe 2)

India has been using natural gas for over three decades. However, domestic gas production has consistently dropped and increasing imports of LNG have also not been able to make up the overall supply deficit that has prevailed for the last three years. Table 3 captures the gas supply vs consumption scenario for the past three years.

Table **3** Gas supply and consumption (**mmscmd**)

	2010/11	2011/12	2012/13
Consumption			
Power generation	78	63	54
Fertilizers	44	39	46
Refineries/ industries	15	13	12
CGD	15	16	17
Petrochemicals	5	6	6
Captive use / LPG shrinkage	12	10	9
Others	9	19	14
Total	178	165	157
Supply			
Domestic supply	141	126	111
Imported LNG	37	39	46
Total	178	165	157

(Source: Annexe 2)

The immediate future scenario for gas availability also seems bleak with limited prospects for increase in domestic production and limitations in LNG supply because of commercial constraints. These concerns are elaborated here.

Domestic natural gas Out of 26 sedimentary basins, only 6 are assessed for natural gas. The identified basins are KG-D6 (both onshore and offshore), Upper Assam, Assam-Arakan, Cambay, Rajasthan, and Mumbai (offshore), which are proven reserves according to the Ministry of Petroleum and Natural Gas. Significant gas resources are estimated at some offshore locations also.

The total recoverable gas reserves identified within the proved and probable categories amount to 267.72 mmscmd (assuming that 100% are recoverable for 20 years @ 365 days / Annum). Almost two-thirds of this (162.96 mmscmd) is in production, little more than half (93.12 mmscmd) has already been drawn and consumed, and 69.84 mmscmd is yet to be drawn. Another 104.76 mmscmd of discoveries is yet to be developed. Thus, available reserves considering yet-to-be-drawn and yet-to-be-developed resources are estimated at 174.6 mmscmd. To these figures should be added 248.32 mmscmd of yet-to-be-found resources, according to resource estimations based on creaming studies. Assuming availability of all the yet-to-be-found resources along with the yet-to-be- developed resources, the maximum total reserves are estimated at 422.92 mmscmd, which, at the 2012/13 level of demand of 293 mmscmd, would last for 28.8 years. This figure also assumes that the current level of gas demand is sustained and all the yet-to-be-found resources yield their estimated quantum. (Annexe 2: pp. 17-25)

The pricing of domestic gas is another contentious issue. Gas produced from the nominated fields of ONGC and OIL is termed APM gas. It was allocated in the past according to the prevailing policies, under contracts that could not be changed. According to the policy prevalent then, the government used differential pricing for APM gas for core sectors (power and fertilizers; $4.2/mmbtu) and non-core sectors (sectors other than power and fertilizers; $ 5.25/mmbtu). However, the proposed uniform increase in gas price to $8.4/mmbtu can effectively lead to a delivered price of about $12/mmbtu, increasing the cost of operations significantly. For the power sector, the landed price would escalate the cost of generation to around Rs 5.40/ kWh. (Annexe 2: pp. 69-71)

Imported liquefied natural gas: Natural gas is imported in the form of LNG through ships. Natural gas, when liquefied and stored at a sub-zero temperature (–162 °C), compresses to 1/600th of its original volume, allowing large quantities of gas to be transported. However, LNG requires high investments along the entire supply chain starting from piped transport of gas from the well head to the port of export, liquefaction at the LNG plant located on the exporting port, transfer through ship, re-gasification at the port of import, and piped transport to the location of the end use.

Although the projected LNG terminal capacity for India in 2013/14 is 101 mmscmd, all of it is not expected to be utilized. The main reason for the limited demand for LNG is the expected landed price. The high capital investment in LNG infrastructure coupled with high maintenance costs necessitates suppliers to impose rigid offtake clauses (take or pay clause) that deter users from entering into long-term contracts. More important, neither suppliers nor users are willing to take long-term risks because there is very limited control over the terminal price of LNG since it is linked to JCC (Japan Crude Cocktail). Even more important, the landed cost of LNG itself is the biggest constraint to any increase in LNG demand. The landed price to end customers would also have to factor in the costs of pipeline infrastructure. As estimated by the senior consultant on gas resources (Annexe 2), an average landed cost for of $17/mmbtu would not be sustainable for power generation as it would translate into a minimum cost of power of around Rs 9/kWh.

Another alternative to India is to export gas through a transnational pipeline. Pipeline transport can be the most cost effective solution for India as gas prices can be negotiated and linked with well head costs, which are low. Although pipeline infrastructure requirements and associated CAPEX would add to the final costs of landed gas, it can be expected to be cheaper than LNG. However, operationalization of such transnational pipelines is also subject to terrain conditions and geopolitical considerations, which may override technical or economic constraints. A case in point is the proposed Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline and Iran–Pakistan–India (IPI) pipeline, which have been under discussion for several years. Against this background, availability of piped gas from other countries seems a remote possibility.

2.1.2.2 Gas turbine technologies (Annexe 1: pp. 86-100)

The technology of gas turbines is more complex than that of steam turbines since it requires a close integration of the compressor, the combustor, and the turbine to strike the right balance between efficiency, reliability, and emissions across the entire operating range.

Gas power plants are preferred for cyclic operation as peaking units because of their short start-up times and their ability to withstand load variations. The efficiency at varying loads is OEM-specific because it is based on the design parameters of the turbine, the compressor, and the burner.

Although gas turbines can be fired with other fuels like distillates, a change in fuel influences the flame characteristics and fluid kinetics and may make the plant less reliable and less efficient. A typical station heat rate for gas turbine plants is 1800 kcal/kWh under Indian conditions.

The three dominant modes of gas-turbine-based power generation are open cycle, combined cycle, and combined heat and power (CHP).

Open cycle gas turbine (OCGT)

In the open cycle mode of operation, the turbine operates on a stand-alone basis. After generation of power, the exhaust gas is released into the atmosphere: since the exhaust gas contains a substantial amount of heat energy at relatively high temperatures (550–600 °C in large turbines), that energy is wasted unless it is recovered.

Aero derivative turbines are best used in open-cycle mode. They have evolved from aircraft engines with requisite modifications for stationary, land-based power for continuous operation. Although limited by their small size for long, units up to 100 MW are now available, making them suitable for peaking or standby power applications.

The open cycle mode offers quick-start capability, flexible generation, short construction time, and low capital costs although high heat loss in the exhaust gas keeps its efficiency low (36%–39%). Capital costs are Rs 20–25 million/MW.

In view of the escalating fuel costs the world over, open cycle (OCGT) operation of gas turbine is nowadays confined to small or mid-size stand-alone units working either at remote locations or working with the grid system as peaking power.

Combined cycle gas turbine (CCGT)

Combined cycle gas turbine is a mature generation technology with a typical module size of 500 MW. In the combined cycle mode, the exhaust gas from the turbine generates high-pressure, high-temperature steam through a heat recovery steam generator (HRSG), and this steam drives a turbine.

Industrial heavy-duty turbines are best suited to operate in a typical large CCGT unit. They are rugged with moderate to high efficiency and are more suited for continuous baseload operation with longer inspection and maintenance intervals than those required for aero-derivative machines. Moderate capital costs, lower emissions, higher efficiency, and flexible generation make the technology suitable for both base and peak support. Today, these machines comprise the bulk of gas-based power generation in the world.

Typical efficiency range under Indian climatic conditions is 55%–57% and capital costs are Rs 40–45 million/MW. However, for countries like India, the future of this technology depends largely on the availability of natural gas at economically sustainable prices.

Combined heat and power (CHP) (Annexe 1: pp. 71-78)

Combined heat and power or co-generation provides both power and heat. Tri-generation, another technology considered under this term, provides cooling as well.

When CHP is designed with a combined cycle mode of operation, the capacity of the steam turbine is increased by adopting duct firing or sometimes full-fledged supplementary fuel firing in the HRSG. Steam is either extracted at the intermediate stage or produced at medium or low pressure for processing applications. If the application demands low-pressure steam in significant quantities, a gas turbine can be used in conjunction with an HRSG without a steam turbine to run in cogeneration mode.

Classical rules of efficiency cannot be applied to cogeneration since electrical energy and heat (steam) are two different levels of energy. Normally efficiencies are expressed in terms of utilization of the primary (fuel) energy. Thermal efficiency of CHP is 60%–80% and typical capital cost is Rs 55–80 million/MW.

However, one key aspect of CHP in the cogeneration mode is that the plants are typically designed around heat requirements—electricity is a secondary output. In India, no district heating system is required, and typical applications of cogeneration are in process industries. Because process industries typically work only within narrow heat regimes, heat takes precedence over electricity, and any shortfall in generation is compensated by grid import. This does not make the technology particularly viable for utilities and, by extension, for power sector planning.

Since only a few tri-generation (trigen) projects have been installed, there is no clear information about the cost of a trigen installation. Further, since trigen projects are customized for a specific project's energy split, no common benchmark can be found for the economics of trigen projects. Considering the limitations related to the need for space cooling, the technology is mainly suitable only to small gas turbines or engines. Typical efficiency is about 80% but it is economical only where electricity, air conditioning, and hot water are required simultaneously, as in hospitals, hotels, and malls. From this context, trigen faces the same issues with respect to utility-scale power generation as cogeneration.

2.1.3 Hydropower resources and technologies

In addition to larger technical and execution challenges, hydropower also has serious resource-related issues. These resources and technologies are briefly described below**. A more detailed analysis of hydro technologies and potential is covered in Annexe 4**.

2.1.3.1 Hydropower resources

In addition to resource risks related to cyclic variations in precipitation and modifications in catchment areas, a key emerging risk is related to climate-induced hydrological changes.

The impact of climate change on groundwater is also expected to be severe because of changes in precipitation and evapo-transpiration. Sea level rise may result in saline water intrusion, affecting the demand for irrigation water. Increased temperature and moisture in the atmosphere may lead to severe climate variability leading to intense rainfall and snowfall events, increasing the potential for floods or droughts, affecting hydro resources severely. The vulnerability of the Indian subcontinent to the impact of the changing climate is a serious matter especially because hydrology affects water resources and agricultural economy. However, very little work has been carried out in India on the impact of climate change on hydrology. Considering this, although risks in hydro resources are acknowledged, they could not be evaluated thoroughly.

2.1.3.2 Hydropower technologies (Annexe 4)

Hydropower is an energy source based on the natural water cycle and is the most mature, reliable, and cost-effective conventional power generation technology available. The annual potential of a hydropower project is proportional to the head and flow of water. Hydropower plants use a relatively simple concept that utilizes the energy potential of flowing water to turn a turbine, which, in turn, provides the mechanical energy required to drive a generator and produce electricity.

Civil construction costs, which are site specific, account for the bulk of project costs. For large hydropower plants, economic lifetimes are at least 40 years. In terms of technology characteristics, hydropower is the most flexible source of power generation and is capable of responding to demand fluctuations in minutes; it has unrivalled 'load following' capability. More important, reservoir-based hydro is the most efficient 'electricity storage' technology, effectively 'storing electricity' over weeks, months, or even seasons. Run-of-the-river technology with pondage can also provide limited storage over days or weeks. In the context of the present study, only run-of-the-river technology with pondage is considered a part of the set of technologies under consideration.

Run-of--river hydro

Run-of-the-river (RoR) hydro typically uses the flow of an existing river to drive turbines and generate electricity. These projects are typically of two types: with pondage and without pondage.

Plants without pondage usually utilize the natural flow of the river and the head available. The energy so produced is seasonal and is totally dependent on the quantity and the quality of the natural flow. Such a configuration makes it nearly 'supply-driven', taking away almost all the benefits of conventional, storage-based hydro. Plants with pondage allow limited storage capability through a separate civil structure that can store water temporarily. Depending on the size of the storage structure, it may be possible to manage hourly fluctuations. This type of plant can be used on parts of the load curve as required, and is more useful than a plant without pondage. Run-of-river schemes are often found downstream of reservoir projects as one reservoir can regulate the generation of one or many downstream RoR plants.

The operation of RoR plants depends heavily on water inflows, and a drawback of these systems is that when inflows are high and the storage available is full, excess water will have to be spilled. This represents a lost opportunity for generation, and the plant design will have to strike a balance between greater capacity (which costs more but can take advantage of high inflows) and lesser capacity (which costs less but cannot profit from high inflows and thus results in water being wasted). The value of electricity produced will determine the extent of such trade-offs between capacity and acceptable levels of wastage of water.

The water-to-electricity conversion efficiency of a typical RoR plant is 90%. The net efficiency of hydro plants depends on the availability and CUF of the plant. The cost of hydro technologies varies largely based on the terrain and altitude. Capital costs of typical hydro plants in India are Rs 4.5–7.5 crore per megawatt and operating costs are approximately 2.5% of the investment cost per kilowatt.

RoR plants are suitable for baseload operation subject to availability of water. The identified future potential for RoR plants in India is 12 033 MW.

Storage hydro

A storage type hydro plant has a reservoir that stores large quantities of water between natural geological formations and an artificial barrier (dam wall). The stored water is then let out in a controlled fashion to a lower elevation, allowing hydro turbines to effectively convert the energy stored in the head and the designed flow into electricity. A reservoir-based hydro plant can be used both as a baseload plant and a peak load plant. The technical characteristics of hydro turbines allow this technology to work on any portion of the load, giving it seamless generation flexibility across its whole operating range.

The advantage of hydropower plants with storage is that generation can be decoupled from the timing of rainfall or glacial melt. For instance, in areas where snow melt provides the bulk of inflows, these can be stored through spring and summer to meet the greater demand for electricity in winter in countries with cold climates or until summer to meet peak electricity demands for cooling. Hydropower schemes with large-scale reservoirs thus offer unparalleled flexibility to an electricity system.

The efficiency of storage Hydro plants is similar to that of RoR plants. The water-to-electricity conversion efficiency is 90%, although the net efficiency depends on the availability and CUF of the plant.

The design of hydropower plants is governed by the site and its topography and, consequently, the cost of a storage-based hydro plant is also highly site dependant. Typical CAPEX may be Rs 60–150 million. However, the operational costs are typically the lowest among many technologies.

Storage-based hydro plants are usually multipurpose projects. Although they are suitable for both base support and peak support, most projects are not operated to meet the peak requirements as many other activities are linked to the storage scheme. The identified future potential for storage hydro in India is 5969 MW.

Pumped storage hydro

Pumped hydro plants allow off-peak electricity to be used for pumping water from a river or a lower reservoir to a higher reservoir to allow its release during peak times. Pumped storage plants are not energy sources but storage devices. Although the losses in the pumping process contribute to the cost of storage, these plants can provide large-scale energy storage and can be useful in providing grid stability.

The original concept behind the development of pumped storage plants was the conversion of relatively low-cost off-peak energy generated in thermal plants into high-value peak power. In developed countries, the schemes are designed to buy cheap off-peak energy from the grid for pumping and sell it during peak hours at a competitive price, which is higher than the purchase price. Indian power industry has not yet commenced such a commercial operation of pumped storage since the cost of common off-peak power for pumped storage is yet to be fixed. Reassessment studies carried out by CEA in 1978/87 identified 63 sites for pumped storage plants (PSP) with total installation of about 96 500 MW with individual capacities varying from 600 MW to 2800 MW. At present, nine pumped storage schemes with aggregate installed capacity of 4785.6 MW are in operation in the country. Out of these, only five plants, with aggregate installed capacity of 2600 MW, are being operated in pumping mode.

The hydraulic, mechanical, and electrical efficiencies of pumped storage determine the overall cycle efficiency, which ranges from 65% to 80%. Capital costs of pumped storage schemes are higher than that of other storage schemes due to the requirement of tail race reservoir. O&M costs will also be higher than those of other storage schemes.

2.1.4 Optional sub technologies

Optional sub-technologies like carbon capture and storage (CCS) and renovation, modernization and life extension are considered separately as they can be associated with more than one technology.

Carbon capture and storage (Annexe 1: pp. 63-70)

Carbon capture and storage (CCS) is the process of capturing CO_2, transporting it to a storage site, and storing it in underground geological storage sites, deep saline aquifers, etc.

In the first stage, CO_2 is captured from the generation process using one of the three common capture methods, namely pre-combustion, post-combustion, and oxy-fuel combustion. In the pre-combustion capture process, which is suited to capturing syngas, syngas is converted to CO_2, which is then captured by chemical or physical absorbents. In the post-combustion process, flue gas from the boiler, which consists mostly of N_2 and CO_2, is captured using chemical solvents. This usually happens downstream of electrostatic precipitators (ESP). However, conventional post-combustion capture using solvent requires steam for solvent regeneration, reducing the net power output. Oxy-fuel combustion uses relatively pure oxygen and recycled CO_2. Because of this, the flue gas volume comes down (owing to absence of nitrogen) and the concentration of CO_2 increases, allowing easier removal through standard post-combustion methods.

Once the CO_2 is captured, it needs to be transported to the storage site through a pipeline. Understandably, the distance between the plant and the storage site has a bearing on the infrastructure (pipeline length and pumping capacity) and costs. The piped CO_2 is pumped into the storage site under compression and locked in. Typical storage sites for CCS include large, depleted gas or oil reserve fields and saline or alluvial aquifers.

Although the expected net output of a plant with CCS may be lowered by about 20%, cost escalation beyond 50% on the levellized cost of energy could be expected in India. Availability of suitable storage sites of large capacities is one of the biggest constraints at some locations. This is particularly the case for India, where large storage sites have not been discovered in the hinterland.

Renovation, modernization, and life extension (Annexe 1: pp 79-85)

The main objective of R&M of thermal generating units is to equip (modify or augment) the operating units with the latest technology and systems to improve their performance in terms of output, reliability and availability, operational flexibility, reduction in maintenance requirements, and ease of maintenance and to minimize inefficiencies. The life extension programme, on the other hand, focuses on refurbishing or replacement of components or systems of the operating plants beyond their original designed life.

Projects involving R&M or LE have shorter gestation periods than those for greenfield projects; also, CAPEX requirements for R&M are estimated to be less than half of those for greenfield projects, nor does R&M require additional land, sources of water, transmission corridor etc., unlike greenfield plants.

However, the experience of R&M in India has not been encouraging. About a third of the R&M projects planned during the 11th Five-Year Plan could not fructify owing to various reasons. Some of the projects initiated were shelved midway owing to doubts about their viability. Further, many of the R&M and LE projects have failed to live up to the predicted performance, partly owing to lack of due diligence at least in some cases.

Considering the past experiences and the fact that subcritical technology is already recommended for a phase-out, R&M and LE for subcritical technology do not seem to be viable options for subcritical plants. Instead, a better strategy could be to use the same infrastructure to replace aged plants with supercritical units. However, from the perspective of the present project, R&M of old subcritical plants with specific focus on making them more flexible in power generation could be a theme worth exploring.

2.2 Screening out of technologies

Technically, the scope of the study includes assessing a chosen suite of conventional technologies across diverse evaluative parameters. Further, sub-technologies like CCS, FBC, and CFBC are also covered to factor in the impacts of these technologies on the technology evaluation parameters.

Based on the above understanding, Table 4 captures the technologies along with the resources that formed the original scope of the study.

Table **4** Resource–technology-sub-technology combination in scope

Resource	Main technologies	Exclusive sub-technology	Optional sub-technology
Domestic coal	Subcritical	Pulverized coal fluidized bed combustion (PFBC, BFBC) Circulating FBC	CCS
Domestic coal Intl coal	Supercritical	Pulverized coal Fluidized bed combustion (PFBC, BFBC) Circulating FBC	CCS
Domestic coal Intl coal	Ultra super critical	Pulverized coal	CCS
Domestic coal Intl coal	Advanced ultra super critical	Pulverized coal	CCS
Domestic coal Intl coal	IGCC	Fluidized bed gasifiers Entrained flow gasifiers	CCS
Domestic coal	UCG with combined cycle		CCS
Domestic LNG	OCGT		CCS
Domestic LNG	CCGT		CCS
Domestic	RM&LE		CCS
Domestic coal Domestic gas LNG	CHP		CCS
-	Large hydro	Run-of-the-river (with pondage) Storage based	Pumped hydro

From Table 4, it is apparent that there are 55 resource–technology/subtechnology combinations in all; a detailed assessment of each would be a wasteful undertaking considering that many may not be suitable or desirable for the present study and even from a broader perspective of technological and strategic suitability. To identify and focus on key technology choices, a screening methodology based on objective criteria is proposed to eliminate some of the technologies.

Criteria for screening out technologies

The three key criteria employed for assessing the suitability of technologies for detailed analysis are regulatory alignment, technological maturity, and independence of planning.

1] **Regulatory alignment** As the ultimate intent of technology assessment is to serve as an input for policy design, policy and regulatory alignment is perhaps the most important criterion for assessing the suitability of a technology at an early stage (screening stage). Typically, regulatory disapproval of a technology implies unacceptability of that particular technology within the regulator's jurisdiction. It is therefore important to consider each technology from this perspective and weed out technologies accordingly.

2] **Technology maturity** Ideally, technology support policies have to consider two aspects: differentiating between viable and unviable new technologies and identifying technologies that are on the verge of obsolescence. Supporting promising technologies that may later prove unviable results in loss of R&D effort and time and hence it is important to differentiate between new technologies by comparing their future potential in terms of commercial availability and cost and performance. On the other hand, relying too much on established technologies without considering their future availability also risks lock-in of capital and other resources. Based on the above considerations, technology maturity is subdivided into the following categories.

   a. **Unproven** technologies are those that are yet at the pre-pilot or pilot stage. The risks associated with these technologies are mainly related to future technology availability, future costs (which may even go up), and future performance.
   b. **Evolving** technologies are typically near to market and state of the art, which have progressed beyond the pilot stage and are nearly commercial. These technologies are desirable because they promise future reduction in costs as well as future increases in performance.
   c. **Mature** technologies are established technologies that are fully proven commercially. Long-term data on costs and performance are available for mature technologies, which have no major risks associated with them. However, the scope for future reduction in costs and increase in performance is also limited.
   d. **Obsolete** technologies are those that are being phased out by manufacturers, policymakers, or regulators. These technologies carry large risks considering that a lock-in with these technologies would deprive the operators of technical support and spares.

   Based on the reasoning provided earlier, unproven technologies and obsolete technologies can be eliminated from consideration.

3] **Independence for planning** As this study focuses on grid-tied electricity and its flexibility, the screening criterion for this category is the extent of dependency of a generation technology on co-products. Although availability of fuels is an absolute objective criterion, co-dependencies based on parallel outputs are also objective criteria because they deprive policymakers of independent planning. In this sense, all technologies that have significant built-in co-dependencies have to be screened out.

Based on the above criteria, the technologies/sub-technologies that are recommended for screening out and the justification for doing so are as shown in Table 5.

Table **5** Technologies to be screened out

Technology	Criteria	Justification	Remarks
Subcritical	Regulatory alignment, obsolete technology	The CEA has suggested that subcritical technologies have to be phased out by the end of the 12th Five-Year Plan (Annexe 1: pp. 8).	Subcritical technology is increasingly losing out to supercritical technology across all metrics including capital costs, performance, and emissions.
RM&LE (subcritical)	Obsolete technology	As most of the current fleet of old plants is subcritical, RM &LE would indirectly imply refurbishing an old technology that is being officially phased out	The technology consultant reports that experience with RM&LE has been very discouraging (Annexe 1: pp. 80-81). Instead, it would be much better to go with supercritical plants at the same location. However, it may be worth exploring the potential for R&M of subcritical plants with a view to make them more flexible in operation.
Advanced ultra supercritical	Unproven technology	No plant is actually operational.	Technology not expected to be commercially available before 2020/21. (Annexe 1: pp. 19).
CCS	Unproven technology	No existing large-scale operating plant. Pilots in progress.	Besides, India has limited geological formations suitable for CCS.
FBC (PFBC/BFBC)	Obsolete technology	Among non-CFBC fluidized technologies, PFBC units are not being manufactured globally. The technology is considered obsolete as the focus is on CFBC. BFBC is available only in small unit sizes and has significantly low efficiency.	
CHP	Co-dependency	CHP plants are typically designed around heat requirements. Inclusion of CHP with all the other generation technologies disregards the fact that CHP cannot be planned and implemented like all other generation technologies. Planning for CHP has to take into consideration planning for heat use (mainly industrial process heating in Indian conditions). This interdependence of CHP technology makes it uncomparable with other pure electricity generation technologies.	While CHP may be a very efficient technology, its co-dependency makes it unsuitable for policy derivation and planning. However, CHP may be a very good choice for process industries and although CHP is not considered for detailed analysis, it will be recommended as a competitive option in the project outputs.

Based on the above screening, the key technologies proposed for detailed assessment are as shown in Table 6.

Table **6** Technologies proposed for detailed comparison

Resource	Main technology	Exclusive sub-technology	Optional sub-technology
Domestic coal International coal	Supercritical	Pulverized coal circulating FBC	
Domestic coal International coal	Ultra supercritical	Pulverized coal	
Domestic coal International coal	IGCC		
Domestic coal	UCG with combined cycle		
Domestic LNG	OCGT		
Domestic LNG	CCGT		
-	Large hydro	Run-of-river (with pondage) storage type	Pumped hydro

Based on Table 6, 16 resource–technology/subtechnology combinations are considered for detailed technology assessment. The next chapter identifies the evaluation criteria for the technology assessment.

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CHAPTER 3

IDENTIFICATION OF TECHNOLOGY EVALUATIVE ATTRIBUTES

3

IDENTIFICATION OF TECHNOLOGY EVALUATIVE ATTRIBUTES

Technologies have diverse impacts on the economy, society, the environment, and climate. Technology costs and technology performance have a direct bearing on the economy (high-cost or low-performance technologies have negative direct and indirect economic ramifications). Pollution due to the technologies and their potential emissions during their lifetime also have implications for society, the environment, and climate.

Each resource–technology-sub-technology combination thus has a unique impact footprint. For example, a domestic-coal-based supercritical plant may have higher social (public health) and environmental (land loss to mining, water contamination by mining, emissions during transport and combustion emissions) impacts than those of an international-coal-based supercritical plant. On the other hand, an international-coal-based CFBC supercritical plant may have lower environmental, social, and climate impacts but higher economic impacts than those of a pulverized-coal-based supercritical plant using domestic coal. In the context of the present study, technology impacts are mainly assessed from the perspective of climate, environment, society and economy.

Table 7 captures the generalized impact tree of different generation technologies.

Table **7** Technology impact tree

IMPACT			
1st order impacts	2nd order impacts	3rd order impacts	Higher order impacts
Climate			
GHG Emissions	Rise in annual average temperatures Increase in incidence of extreme climate events Variability in average precipitation	Glacial melting leading to increase in sea level rise and land submergence Increased loss of fresh water due to glacial melting and evaporation Increase in loss of human and animal life and infrastructure damage Increased incidence of floods and famines resulting in crop loss, biodiversity loss and human loss	Decrease in quality of life Increased food and water scarcity Increased human mortality Increased social strife Species extinction
Environment			
Emission of pollutants in air, water, and land	Air pollution Water contamination Soil contamination	Acid rains Adverse health impacts on humans and biosphere due to air, water, and soil contamination Crop and biodiversity loss	Increased mortality/morbidity Increased health costs Food scarcity and food contamination Water security Disruption of food chain Social strife Species extinction (flora and fauna)

Land use	Impact on agriculture, forests, etc. Displacement of communities and endemic species	Localized land stress leading to increased incidences of human–human, human–animal, human–environment conflicts	Scarcity of food and shelter Loss of livelihoods Increased social strife Decreased quality of life
water use	Degradation of water bodies Water quality impact Groundwater depletion	Localized water stress leading to increased incidences of human–human, human–animal, and human–environment conflicts	Scarcity of water Increased social strife Decreased quality of life
Society			
Employment generation	Increase in income and consumption	Better quality of life	Decrease in social inequity and strife
Loss of livelihoods	Decrease in income and consumption	Decrease in quality of life	Decrease in well being Increase in social inequity, social strife
Displacement of population	Possible loss of livelihoods and shelter	Decrease in quality of life	Increase in social inequity, social strife
Public health	Increased incidences of morbidity and mortality Increased costs of healthcare	Decrease in quality of life	Increase in social inequity, social strife
Economy			
Commodity prices Sector economics	Impact on commodity demand	Impact on sector economics	Impact on economy as a whole
	Impact on inflation	Decreased buying power	Impact on economy as a whole

However, from a policy perspective, technology choices should ideally go beyond mere impact evaluation to consider other implications. In this context, aspects like technology desirability (technology access, strategic flexibility), special infrastructure needs, concerns related to energy security, and macroeconomic risks assume importance. For example, technology availability and performance have a bearing on deployment possibility and resource-use efficiency respectively. Similarly, aspects related to new infrastructure needs (for example, infrastructure for LNG imports) may have a direct or indirect bearing on the economy and final pricing while import dependence on resources or technology has a bearing on energy security and macroeconomics.

Although implications related to implementation risks (centre–state conflict, public opposition, technical capability, etc.) are also important, they should not dictate technology selection and choice because they can be viewed more as a function of existing policy regime and institutional mechanisms, which can be altered to favour or disfavour certain technologies.

Based on the above perspective, the seven main attributes for technology assessment considered for the present study are climate, the environment, society, economy, technology, infrastructure, and policy risks. ***Although the focus of the project is on flexible generation technologies, the attribute of generation flexibility along with its sub-attributes is covered separately in Chapter 5. (Please refer also to Chapter 1, Background and Introduction). The subsequent narrative discusses evaluative parameters without considering generation flexibility.***

For each of the seven evaluative attributes, a comprehensive list of sub-attributes is prepared so that the variation in technology characteristics across these sub-attributes can be mapped and assessed comparatively. For example, under the attribute technology, some of the identified sub-attributes could be technology maturity, gross efficiency, net efficiency, and fuel flexibility.

At the first level, a comprehensive list of sub-attributes was identified through an internal brainstorming session, which listed all possible sub-attributes or parameters under the main attributes. Understandably, many of the listed sub-attributes may not be relevant to the study while many other sub-attributes may be subsumed under other broader sub-attributes. For example, the attribute climate was considered to have many sub-attributes mainly related to the second- and third-order impacts. However, since the study focuses on technology, the only link between technologies and climate is emissions, which is a first-order impact. Similarly, under the attribute technology, sub-attributes like auxiliary consumption and gross efficiency are subsumed under the sub-attribute of net efficiency.

Considering these complexities, the exhaustive list of sub-attributes was analysed to filter sub-attributes that were considered relevant and had individual standing. Based on specific interactions between the project team and the expert group members, a final list of sub-attributes that were considered important from the perspective of technology evaluation was drawn up.

Table 8 captures the exhaustive list of sub-attributes with their definition and the proposed justification for the inclusion or exclusion of a particular sub-attribute.

Table **8** Exhaustive list of sub-attributes for evaluation

Climate		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
GHG footprint	C02 equivalent footprint of each technology in tCO_2/MWh	Included as sub-attribute as this is the only link between technologies and climate
Impact of emissions on local environmental and social externalities (forests and biodiversity)	The impact of GHG emissions on local environment and society	Eliminated as a sub-attribute as the relation of technologies with this sub-attribute can only be through emissions, which is already considered as a separate sub-attribute
Water security	Impact due to climate change on the availability of required quantity and quality of water for health, livelihoods, and economic production	Eliminated as a sub-attribute as the relation of technologies with this sub-attribute can only be through emissions, which is already considered as a separate sub-attribute
Food security	Impact due to climate change on the availability of required quantity and quality of food	Eliminated as a sub-attribute as the relation of technologies with this sub-attribute can only be through emissions, which is already considered as a separate sub-attribute
Environment		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Air pollution (S0x, SPM)	The S0x and SPM footprint of technology per unit of generation [Make S0x consistent throughout]	Included as a sub-attribute to independently establish the impacts of S0x and SPM on air pollution. This is considered to have an independent value because apart from being a measure of air pollution and a contributor to adverse impacts on public health; it also has other implications that go beyond human scale (acid rains, effect of SPM on mammals).
Water use and pollution	Extent of impact of concerned technology on water in terms of	Included as sub-attribute as it is critical from environmental perspective

	consumptive water use and in terms of generating untreatable waste water	
Land diversion and land use	Potential of the technology to divert land from other uses (forests, agriculture) and its ultimate impact of land pollution that results in change of land use (ash pits, etc.).	Included as this covers land diversion from populated non-forests or prime lands and also indicates the possibility of soil pollution and its effect on or land usability
Loss of biodiversity	Potential for loss of biodiversity in terms of loss of fauna and flora and endemic species	Included as a separate attribute to reflect the potential for material loss of other life forms and in this sense is separate from the land diversion sub-attribute
Society		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Public health	Extent of impact of concerned technology on public health due to emissions and pollution (land, air, water)	Included sub-attribute as an independent measure as it is a function of all levels of pollution (air [Sox, SPM], water, land [soil]).
Displacement potential	The potential of the technology for displacement of people (mainly those living in small villages and tribals) from their natural habitat/shelters	Included as a sub-attribute as it represents fundamental social issues related to the rights of the society, community, and individuals
Employment generation	The potential of a technology to create employment through its life cycle (employment generation potential from resource extraction stage to final delivery of electricity at the generator bus bar)	Included as a sub-attribute to consider the beneficial aspects of technologies as these are some of the considerations that go into locating and approving investments
Technology		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Technology maturity	Current state of readiness of the technology in terms of its commercial availability	Included as an evaluative sub-attribute as it represents a parameter that is important from availability and deployment perspectives.
Gross efficiency	The ratio between the useful output of a generator and the input fuel, in energy terms [mainly reflects the thermal efficiency (heat rate)]	Eliminated. Gross efficiency does not give an independent picture but only indicates the thermal efficiency of the system without considering total energy consumption (auxiliary consumption)
Auxiliary consumption	Energy consumption by unit auxiliaries and station auxiliaries expressed in percentage of total unit generation	Eliminated. Auxiliary consumption considered independently does not convey any meaning except in combination with gross efficiency when the combination signals net efficiency
Net efficiency	Net efficiency is the ratio of useful electricity output and total primary energy input	Included as a sub-attribute as net efficiency gives an indication of resource use efficiency as well as technology acceptability
Fuel flexibility	Ability to work with varying level of fuel mix. For example, ability to vary coal blending ratio during plant life operation.	Included as a sub-attribute as fuel flexibility has a major implication for CFBC-based coal technologies that have the flexibility to change their fuel mix ratio by allowing blending of cheaper or cost-effective coal in the course of its operation (This advantage is not there for PC-based systems, which are operationally sensitive to fuel variations.)
Domestic manufacturing base	The current domestic manufacturing ability of existing technology and future ability of domestic manufacturing of emerging technologies	Eliminated. Not considered as an evaluative parameter because technologies are mainly assessed only from perspective of technology access, technology licensing and operations support requirements considering that a component level or a resource level analysis will entail a separate detailed study, much larger in scope than the present study. Further, domestic manufacturing base is considered as a post-analysis requirement rather than as an a priori requirement. Further, it is also assumed that future

		manufacturing base for a technology will develop if the technology is favoured by policy.
Unit sizes	Megawatt range of a single unit of the concerned technology.	Eliminated. Not considered as a sub-attribute as unit sizes are related to technology in the case of coal and to other factors in the case of gas and hydro. Individually, unit sizes imply nothing except the capacity of the technology to augment generation capacity. In this sense, it is not considered central to the study and is excluded.
Economy		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Cost of generation (range)	Expected range of cost of electricity ex-bus as estimated by a regulator and expressed in rupees per kilowatt	Included. Key central characteristic; revised as "cost of electricity"
Capital costs (range)	Expected range of capital costs of the concerned technology expressed per megawatt	Included. Revised as "CAPEX"; considered as an indicator of the investment quantum for technologies and also to reflect public-sector exposure assuming 70% debt
Variable costs (range)	Expected range of variable costs of the concerned technology expressed per megawatt	Included. Revised as "OPEX"; considered as relevant OPEX is linked to fuel costs
Equity investment issues	Any issues with raising equity from a utility perspective for a given technology	Eliminated. These issues are related more to extraneous market or sectoral risks rather than to technologies themselves and hence are not considered central to the technology evaluation process. Further, these issues are dependent on policy also and hence cannot be used for policy derivation.
Debt investment issues	Any issues with raising debt from financiers for a given technology	Eliminated. These issues are related more to extraneous market or sectoral risks rather than to technologies themselves and hence are not considered central to the technology evaluation process. Further, these issues are dependent on policy also and hence cannot be used for policy derivation.
Infrastructure		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Railways	Built physical infrastructure: requirement of additional investments for development of railways for a concerned technology	Infrastructure needs across technologies are different as each technology family requires a different set of infrastructure. Against this background, all the infrastructure sub-attributes are combined as one sub-attribute infrastructure.
Ports	Built physical infrastructure: requirement of additional investments for development of ports for a concerned technology	
Roads	Built physical infrastructure: requirement of additional investments for development of roads for a concerned technology	
Water pipelines	Built physical infrastructure: requirement of additional investments for development of water pipelines for a concerned technology	
Townships	Requirement of construction of townships for workers in generation plants	Eliminated. Not relevant considering the scope of the study
Power evacuation	Requirement of special power evacuation for the concerned technology	Eliminated. None of the technologies considered demands special power evacuation requirements

Policy Risks		
Exhaustive list of sub-attributes	**Definition**	**Justification for retaining or screening out**
Resource risk (availability)	Potential for risks arising from international policy changes, lack of access to transport routes, nationalistic polices by exporting countries, disruption of supply chain, resource capturing, etc.	Included as a sub-attributes as this has very significant implications for energy security
Resource risks (price)	Potential for risks arising from lack of control over international prices of coal and LNG. Risks arising from losing regulatory control over electricity costs due to pass-through of fuel costs.	Included as a sub-attribute as this has very significant implications for energy security
FE risks	Potential for impact of technology on foreign exchange exposure	Included as a sub-attribute to consider the larger macroeconomic impact independent of the risk of price rise
Energy security	Security of energy resources and energy supply systems for supporting economic activities	Eliminated. This aspect is covered separately as resource risk (availability) and resource risk (price).
Policy or regulatory fit	Compliance of the given technology with the present policy and regulatory framework	Eliminated. As the intent of the study is to derive technology priorities for policy-making using a new evaluation system, this sub-attribute cannot be included as an evaluative parameter.
Cost of subsidies	Implication of subsidies required for the technology	Eliminated. Subsidies are not considered as evaluative parameters as they have emerged from present policy or regulatory considerations, which are being put to test in this study. Further, because many of the technologies under consideration are new, subsidy support cannot be assessed.

Based on the above considerations, 18 sub-attributes (under 7 attributes) are considered relevant and important for technology evaluation. It is worth noting that the consideration of soft attributes like the environment, climate, and society on par with other attributes like techno-economics and policy agendas is a deliberate decision to bring these 'soft impacts' at the forefront of policy analysis and the policy-making exercise. However, it can be contended that each of the identified sub-attribute may not be equally important, and stakeholders representing different viewpoints (public, private, environmentalists, economists, policymakers) would argue for different levels of importance for each sub-attribute.

To factor in the concept of relative importance and the differences in perception, the study asked the expert group to assign weightings to the final list of sub-attributes. As the expert group represents a diverse group representing different domains such as policy, regulation, economy, the environment, society, technology, and climate, it is assumed that the average weighting assigned by the expert group across sub-attributes represents a balanced picture of allocation of weightings from the perspective of a diverse stakeholder group. Based on inputs from the expert-group members, the final weightings assigned across each sub-attribute are shown in Table 9.

Table **9** Allocation of weightings to sub-attributes

Main attributes	Weighting	Sub-attributes	Weighting
Climate	9.21	GHG footprint	9.21
Environment	19.41	Air pollution (SOx, NOx, SPM)	5.72
		Water use and pollution	5.78
		Land diversion and land use	3.69
		Loss of biodiversity	4.22
Society	13.02	Public health	5.62
		Displacement potential	4.35
		Employment generation	3.06
Economy	19.63	Cost of generation (range)	7.59
		Capital costs (range)	5.91
		Variable costs (range)	6.13
Technology	18.64	Technology maturity	6.82
		Net efficiency	7.05
		Fuel flexibility	4.78
Infrastructure	5.77	Infrastructure	5.77
Policy risks	14.32	Resource risk (availability)	5.83
		Resource risks (price)	4.55
		FE risks	3.94
Sum	100	Sum	100.00

These weightings are factored in the technology assessment exercise in Chapter 4.

CHAPTER 4

TECHNOLOGY ASSESSMENT MATRIX AND FIRST ORDER OF PRIORITIES

4

TECHNOLOGY ASSESSMENT MATRIX AND FIRST ORDER OF PRIORITIES

The most systematic way to evaluate technologies across different attributes is through a matrix with each attribute as a separate row and each column as a separate technology. Such a representation aids methodical and meticulous consideration of all the factors involved in the assessment. Table 10 shows the matrix used in the present study.

Table **10** Matrix representation for technology assessment (TA Matrix)

Main attribute	Sub-attributes	Technology 1	Technology 2	Technology	Technology n
Climate	GHG footprint				
Environment	Air pollution (SOx ,SPM)				
	Water use and pollution				
	Land diversion / land use				
	Loss of biodiversity				
Society	Public health				
	Displacement potential				
	Employment generation				
Economy	Cost of generation (range)				
	Capital costs (range)				
	Variable costs (range)				
Technology	Technology maturity				
	Net efficiency				
	Fuel flexibility				
Infrastructure	Infrastructure				
Policy risks	Resource risk (availability)				
	Resource risks (price)				
	Foreign exchange risks				

However, even with a matrix, it is difficult to compare and prioritize technologies as none of the considered technologies is superior to other technologies across all attributes. In such a scenario, combining weightings (numerical data) with the matrix cell data (which may or may not be numerical) to derive technology priorities would require conversion of the matrix cell information into a quantifiable scale that can represent preference strengths for technologies across each sub-attribute.

It was realized early on that a qualitative logic-based technology priority order would reflect individual perceptions and prejudices; therefore, a new quantification methodology was developed for deriving technology priorities quantitatively. **Details of the quantification methodology and preference scoring are given in detail in Annexe 3**.

To aid representation, the main technology assessment matrix is divided into sub-matrices, each representing one sub-attribute.

Sub attribute: GHG footprint

Under main attribute: climate

Definition: CO_2 equivalent footprint of each technology in kg CO_2/kWh

Weighting: 9.2

Supercritical PC	***Domestic coal:*** CO_2 0.94 kg/kWh; *(Annexe 1: pp-10, xxiv)* ***Imported coal:*** CO_2 0.88 kg/kWh; *(Annexe 1: pp-xxv)*	**OCGT**	CO_2 0.8–0.9 kg/kWh *(Annexe 1: pp-xxiv)*
Supercritical CFBC	***Domestic coal:*** CO_2 0.9 kg/kWh; *(Annexe 1: pp-xxiv)* ***Imported coal:*** CO_2 0.88 kg/kWh; *(Annexe 1: pp-xxv)*	**CCGT**	CO_2 0.5–0.6 kg/kWh *(Annexe 1: pp-89,xviii,xxiv)*
Ultra supercritical PC	***Domestic coal:*** 0.88 kg/kWh (assumed) ***Imported coal:*** CO_2 0.85 kg/kWh; *(Annexe 1: pp-xxiv)*	**RoR, storage-based hydro, pumped hydro**	Majority of lifecycle GHG emission estimates for hydropower cluster between 4 and 14 g CO_{2eq}/kWh, but under certain scenarios, storage-based hydropower has been shown to potentially emit over 150 g CO_{2eq}/kWh, which is significantly higher than RoR schemes. [1]
IGCC	***Domestic coal:*** 0.82–0.92 kg/kWh (assumed) ***Imported coal:*** CO_2 0.8–0.9 kg / kWh; *(Annexe 1: pp-49,xxiv)*		
UCG	CO_2 0.7 kg/kWh; *(Annexe 1: pp-xxiv)*		

[1] IPCC (2012). Special Report on Renewable Energy Sources and Climate Change Mitigation. Intergovernmental Panel on Climate Change, pp 461-488

Note

- Considering the higher GCV of imported coal than that of domestic coal, CO_2 emissions from imported coal are assumed to be lower than those from Indian coal (A Chandra, H Chandra (Feb 2004). Impact of Indian and imported coal on Indian thermal power plants. Journal of Indian and Scientific Research, Vol. 63, pp 156-162)
- GHG emissions from domestic-coal-based IGCC and ultra supercritical plants are based on the assumption that these technologies, proven for international coal, will be modified to run efficiently on Indian coal.

Sub attribute: Air pollution

Under main attribute: Environment

Definition: The SOx, NOx, and SPM footprints of technology per unit of generation

Weighting: 5.72

Supercritical PC	***Domestic coal:*** SO_2 3.3 g/kWh; SPM 0.12 g/kWh; NOx 1.0 g/kWh *(Annexe 1: pp-10, 129-130, xxiv)* ***Imported coal:*** SO_2 3.3 g/ kWh; SPM 0.1 g/ kWh; NOx 1.0 g/ kWh *(Annexe 1: pp-120, xxv)*	**OCGT**	Negligible SO_2 and SPM emissions NOx 0.1–0.15 kg/kWh *(Annexe 1: pp-xxiv)*
Supercritical CFBC	***Domestic coal:*** SO_2 0.4–0.8 g/kWh; SPM 0.12 g/ kWh; NOx 0.2–0.25 g/kWh *(Annexe 1: pp-24-25,29, xxiv)* ***Imported coal:*** SO_2 0.4–0.8 g/kWh; SPM 0.1 g/ kWh; NOx 0.2–0.25 g/kWh *(Annexe 1: pp-xxv)*	**CCGT**	Negligible SO_2 and SPM emissions NOx 0.07–0.1 g/kWh *(Annexe 1: pp-89,xxiv)*
Ultra supercritical PC	***Domestic coal:*** SO_2 3.2 g/kWh; SPM 0.12 g/kWh; NOx 0.96 g/kWh (assumed) ***Imported coal:*** SO_2 3.2 g/kWh; SPM 0.1 g/kWh; NOx 0.96 g/kWh *(Annexe 1: pp-129,xxiv)*		
IGCC	***Domestic coal:*** SO_2 0.7 g/kWh; SPM approx 0.06 g/ kWh; NOx 0.4 g/kWh (assumed) ***Imported coal:*** SO_2 0.7 g/kWh ; SPM 0.04 g/kWh NOx 0.4 g/kWh *(Annexe 1: pp-40-41, xxiv)*	**RoR, storage-based hydro, pumped hydro**	Hydropower does not cause any direct air pollution during the operation phase. Construction phase may cause marginal air pollution.
UCG	Negligible SO_2 and SPM emissions NOx 0.07–0.1 g/kWh *(Annexe 1: pp-45,48, xxiv)*		

Note: Sulphur content in domestic and imported coal is assumed to be 0.3%–0.5% and 0.6%–0.8% respectively.

Sub attribute: water use and pollution

Under main attribute: environment

Definition: Extent of impact of concerned technology on water in terms of consumptive water use and in terms of generating untreatable waste water

Weighting: 5.78

<table>
<tr><td>Supercritical PC</td><td>2.2–2.5 m^3/MWh
(Annexe 1: pp-10,122, xxiv)
Domestic coal: water pollution due to coal mining, coal washing and processing, power plant operation, and ash handling.
Imported coal: burden of water use and pollution for coal mining not on the local environment. Water pollution due to power plant operation, ash handling, and thermal pollution if open cycle cooling system.</td><td>OCGT</td><td>Negligible water consumption for operation.
(Annexe 1: pp-xxiv)
Domestic gas: Onshore gas exploration and drilling affect water quality and quantity. During the process, methane gas and toxic chemicals leach out from the system and contaminate nearby groundwater. Offshore exploration may not have any significant impact
Imported gas: no water pollution due to exploration and drilling on the local environment</td></tr>
<tr><td>Supercritical CFBC</td><td>2–2.5 m^3/MWh
(Annexe 1: pp-122, xxiv)
Pollution (domestic coal): same as that of supercritical PC with domestic coal
Pollution (imported Coal): same as that of supercritical PC with international coal</td><td>CCGT</td><td>0.8–1.0 m^3/MWh for operation.
(Annexe 1: pp-xviii, xxiv)
Domestic gas: same as above
Imported gas: same as above</td></tr>
<tr><td>Ultra supercritical PC</td><td>2.1–2.2 m^3/MWh
(Annexe 1: pp-122, xxiv)
Pollution (domestic coal): same as that of supercritical PC with domestic coal
Pollution (imported Coal): same as that of supercritical PC with international coal</td><td>RoR</td><td>As upstream and downstream stages require less water, life cycle water use is close to zero for RoR hydropower plants [1]</td></tr>
<tr><td>IGCC</td><td>1.6–2.0 m^3/MWh,
Water use about two-thirds that of a comparable coal plant.
(Annexe 1: pp-37, xxiv)
Pollution (domestic coal): Same as that of supercritical PC with domestic coal
Pollution (imported Coal): Same as that of supercritical PC with international coal</td><td rowspan="2">Storage-based hydro, pumped hydro</td><td rowspan="2">Technically, consumptive water use can mainly happen only through evaporation [1]
But the total water loss could be significantly lower than that of coal. Hydropower causes changes in chemical composition and water temperature (downstream), changes in seasonal flow and flooding regimes, alteration of hydrological cycle downstream, change in sediment loads of water [1]. However, compared to other combustion technologies, these impacts are at best marginal.</td></tr>
<tr><td>UCG</td><td>Water demand lower than PF technology. Approx 1-2 m3/MWh (assumed)
Impacts on groundwater quality and quantity i.e. pollution of deep aquifers due to underground combustion and depletion of shallow aquifers, release of VOCs into ground water. Impacts could be same as those of IGCC (imported coal)
(Annexe 1: pp-45,49)</td></tr>
</table>

[1] IPCC (2012). Special Report on Renewable Energy Sources and Climate Change Mitigation. Intergovernmental Panel on Climate Change, pp 461-488

Note

- Domestic coal mining pollutes water through leachates, solids, heavy metals, and other effluents in addition to contamination through acid mine drainage and coal washeries. This would suggest that the water impacts of domestic-coal-based plants would be substantial compared to those of imported coal because the impacts of water use and pollution from coal mining and coal handling are absent in the case of imported coal. Further, imported-coal-based plants are more likely to come up at coastal locations, resulting in lower use of freshwater for operations than that required for domestic-coal-based plants, which are mainly in the hinterland.
- Compared to the life cycle water use impacts of coal based technologies, the water use impacts of hydro are expected to be low. Water pollution impacts of hydro technologies are assessed to be extremely low.

Sub attribute: land diversion and land use

Under main attribute: environment

Definition: Potential of the technology to divert land from other uses (forests, agriculture) and its ultimate impact of land pollution that results in change of land use

Weighting: 3.69

Supercritical PC	*Domestic coal:* 1.04 acre/MW for 3 × 660 MW pithead plants [2]. Large extent of land diversion for coal mining. In terms of allocated coal mining areas, the estimates vary from 0.3 acre/MW to about 0.9 acre/MW. However, a 20-year land impact could be as high as 19.5 acres/MW (calculated) if we include overburdens, land reclamation for processing, transport and settlements, and land rendered waste from for opencast mining [1] Land pollution impacts are mainly related to land/soil contamination due to mining and washing operations at and near mining areas, loss of topsoil and soil contamination in ash handling operation	OCGT	*Domestic gas:* Very less space required for individual units. Unit sizes are usually small to medium. *(Annexe 1: pp-xviii)* Land diversion for pipeline infrastructure *Imported LNG:* very less space required for individual units. Unit sizes are usually small to medium. Land intake for port infrastructure
	Imported coal: 0.42 acre/MW for 3 × 660 MW coastal plant infrastructure without merry-go-round (MGR) and cooling tower [2]. Additional land requirement as compared to domestic-coal-based plants only on account of port infrastructure, which will be significantly less than the land use under coal mining. Port infrastructure is also likely to be a shared infrastructure and not a dedicated infrastructure. Land pollution impacts are mainly on account of ash handling	CCGT	*Domestic gas:* 0.15 acre/MW. Unit sizes are usually medium to large. *(Annexe 1: pp-xviii, xxiv)* High ratio of power output to the area occupied. Land diversion for pipeline infrastructure. *Imported gas:* 0.15 acres/MW. Unit sizes are usually medium to large. Land intake for port infrastructure.
Supercritical CFBC	*Domestic coal:* 1.1–1.2 acres/MW for pithead plant infrastructure. *(Annexe 1: pp-xxiv)* Land diversion for coal mining similar to that for supercritical PC Land pollution impacts are similar to domestic-coal-based supercritical PC units *Imported coal:* Land use and land diversion slightly higher than those for supercritical PC of comparable sizes. Land diversion for coal mining similar to that of supercritical PC. Land pollution impacts are similar to those of imported-coal-based supercritical PC units.	RoR	RoR projects avoid the need to build large reservoirs as in traditional hydro plants. RoR projects are constructed near streams or rivers. Therefore land diversion is usually less than that for other reservoir-based hydro projects.

Ultra supercritical PC	*Domestic coal:* 0.77 acre/MW for 4 × 800 MW interior plant [2]. Land diversion for coal mining may be marginally less than that of supercritical PC. *Imported coal:* 0.30 acre/MW for 4 × 800 MW coastal plant without MGR and cooling tower [2]. Land diversion for coal mining may be marginally less than that of supercritical PC.	**Storage-based hydro, pumped hydro**	The extent of land diversion varies with the size of the plant and is site specific. A project catering only to hydro power needs causes little submergence. A sample of 12 projects of NHPC contributing 6231 MW of power required submergence of only 4850 ha of land, i.e. the area submerged was only 0.78 ha or 1.9 acres/MW.
IGCC	Assumed similar to supercritical PC units		
UCG	0.15 acre/MW. Lesser land diversion due to absence of coal mining, handling and ash disposal ponds. *(Annexe 1: pp-49, 50, xxiv)*		

[1] A 10-million-tonne opencast coal mine in 20 years has the potential to destroy about 800 ha of land. This translates to 7.8 ha/MW (19.5 acres/MW) assuming a PLF of 80% for a 1 MW plant over 20 years. (Dhruv Katoria (2003). Environment Impact Assessment of Coal Mining, International Journal of Environmental Engineering and Management. ISSN 2231-1319, Volume 4, Number 3, pp. 245-250).

[2] Based on the definition, the focus of land use for coal plants is on the impacts during the entire life of a coal plant including coal mining, intermediate processing, transport, plant infrastructure, and post-combustion treatment (ash handling). In terms of the share of land use, the land use impacts (in terms of area diverted) are far higher for mining operations than for other downstream activities. Even qualitatively, land use impacts of mining are more likely to affect forest and agricultural areas. The land use impacts of plant infrastructure are on account of many factors including location, coal storage capacity, coal transport, water storage capacity, and type of condenser cooling system. The cumulative impacts of all these factors are taken as the base land use figures for a typical coal-based power plant. (CEA (Dec 2007). Report on the Land Requirement of Thermal Power Stations. Central Electricity Authority))

[3] Ministry of Power. http://powermin.nic.in/JSP_SERVLETS/jsp/Hydro_faq.htm#23

Note

- The comparison between domestic-coal-based plants and imported-coal-based plants assumes domestic-coal-based plants to be at either pithead locations or close to mined coal. Imported-coal-based plants, on the other hand, are assumed to be mainly in coastal regions.
- Land/soil pollution impacts for coal-based plants are mainly related to contamination of soil during mining, coal handling, and ash depositions in areas around the plants. Gas technologies have limited impact on soil except marginal impacts at the gas recovery stage.
- For large hydro, land-use impacts suggest nearly similar or even lower land use footprint, even for reservoir-based hydro projects, than that for coal-based projects. The impacts of RoR would be even lower. In terms of land pollution, hydro technologies are the most desirable.

Sub attribute: loss of biodiversity

Under main attribute: environment

Definition: Potential for loss of biodiversity in terms of loss of fauna and flora and endemic species

Weighting: 4.2

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	*Domestic coal:* main impacts are related to coal mining although there would be minor impacts from thermal pollution. Coal deposits in forested areas are mostly co-located with forest areas. 1,104,000 ha of standing forest in central India (north-eastern Andhra Pradesh, eastern Maharashtra, Madhya Pradesh, Chhattisgarh, Odisha, and Jharkhand) could be diverted for coal mining as the majority of India's untapped coal reserves lie in this region. A large portion of these lands also support endangered tiger and leopard populations [1]. *Imported coal*: impacts of coal mining are entirely avoided. Major impacts would be related to loss of coastal habitats and depletion of marine resources and aquatic species due to thermal pollution. But these would be significantly lower than those of coal mining	OCGT, CCGT	*Domestic gas*: impact on biodiversity significantly less than that of coal-based technologies. Gas mining may cause habitat disturbance. *Imported LNG:* impact on biodiversity less than that of coal-based technologies. Loss of biodiversity due to pipeline infrastructure from ports to end-use station. Biodiversity disturbances due to port infrastructure [2].
UCG	Surface impacts minimum due to absence of mining. Significantly less impacts on flora and fauna compared to surface mining	RoR, storage-based hydro, pumped hydro	The biodiversity impacts of large storage hydro projects are huge considering that large biodiversity-rich riparian ecosystems are affected permanently. RoR projects are primarily located in hilly areas, where forest cover is comparatively high but diversion typically requires very little area as compared to that for a storage-based hydropower system [3].

[1] Greenpeace (2012). How coal mining is trashing tiger land, Greenpeace-India

[2] Vassilis Tselentis (2011), Port operation and biodiversity. Sustainable Management for European local ports www.seinemaritime.net/suports/uploads/files/porto%20LagosBIODIVERSITY%20%26%20PORPO%20Tselentis.pdf

[3] Ministry of Power. http://powermin.nic.in/JSP_SERVLETS/jsp/Hydro_faq.htm#23

Sub attribute: public health

Under main attribute: society

Definition: extent of impact of concerned technology on public health due to emissions and pollution (land, air, water)

Weighting: 5.62

Supercritical PC, Supercritical CFBC, Ultra supercritical PC, IGCC	***Domestic coal:*** air pollutants can increase incidence of chronic lung (asthma, COPD, cancer) and heart diseases. The presence of mercury and other POPs (persistent organic pollutants) can affect cognitive development of children. Particulate matter can adversely affect blood and vasculature in addition to heart, lungs, and brain. Fine particles less than 2.5 µm can enter the blood stream and affect heart function. Release of heavy metals or radio isotopes through coal washing and ash handling operation in effluent water has the potential to contaminate groundwater and soil and enter the food chain, resulting in cumulative accumulation of potentially toxic elements like mercury and lead in the body. Soil at coal-fired power plant sites can become contaminated with various pollutants from the coal and take a long time to recover, even after the power plant closes down. [1]. In addition coal mining brings in its own attendant hazards related to respiratory problems and water, soil and dust pollution ***Imported coal:*** Health impacts of coal mining are entirely avoided. Almost similar impacts in physical terms for plant operations.
UCG	UCG causes organic and toxic materials to remain in the underground chamber after gasification. They are likely to leach into groundwater, unless appropriate site selection is done Exposure to organic and toxic material in water can cause cancer, childbirth disorders, and other illness.
OCGT, CCGT	Due to shorter stacks and lower temperatures of flue gas compared to those of coal-fired plants, as well as higher likelihood of being located in more densely populated areas, smoke plumes from natural-gas-fired power plants may be more susceptible to downwash and will not be dispersed as much, and thus pose a greater hazard for the population near the facility. The review of emissions suggests ultrafine particles may be emitted in greater numbers, have a separate impact on human health, and are perhaps more of a health concern than larger particles [2].
RoR Storage-based hydro, Pumped hydro	Still-standing water bodies such as reservoirs can lead to increase in waterborne diseases. [3]. However, the overall life cycle health impacts and the extent of health impacts of hydro projects over their lifetime would be significantly lower for all hydro technologies.

Note:

[1] HEAL (Mar 2013). The Unpaid Health Bill: How coal power plants make us sick. A report from the Health and Environment Alliance, pp 36-37
www.envhealth.org/IMG/pdf/heal_report_the_unpaid_health_bill_how_coal_power_plants_make_us_sick_final.pdf

[2] EPRI (Aug 2012). Air Quality Impacts from Natural Gas Extraction and Combustion, Electric Power Research Institute.

[3] IPCC (2012). Special Report on Renewable Energy Sources and Climate Change Mitigation. Intergovernmental Panel on Climate Change, pp 467-468

- Coal dust and coal particles stirred up during the mining process, as well as the soot released during coal transport, can cause severe and potentially deadly respiratory problems; chronic exposure to coal dust can lead to black lung disease. The use of explosives at opencast mining sites releases large amounts of dust, which can affect the respiratory health of nearby communities. These explosives are also created from chemicals that have been linked to poisoning in local area residents

  Coal ash contains heavy metals including arsenic, lead, mercury, cadmium, chromium, and selenium, as well as aluminium, antimony, barium, beryllium, boron, chlorine, cobalt, manganese, molybdenum, nickel, thallium, vanadium, and zinc. If eaten, drunk, or inhaled, these toxicants can cause cancer, cognitive deficits, developmental delays and behavioural problems, heart damage, lung diseases, respiratory distress, kidney diseases, reproductive problems, gastrointestinal illness, birth defects, and impaired bone growth in children.

  (Ref: PSR (2010), Coal Ash The toxic threat to our health and environment, Physicians for Social Responsibility and Earthjustice)http://www.sourcewatch.org/index.php/Health_effects_of_coal

- (Exposure to ultrafine particles causes respiratory and cardiovascular diseases including changes in lung function, inflammation of airways, enhanced allergic responses, vascular thrombogenic effects, altered endothelial function, altered heart rate and heart rate variability, accelerated atherosclerosis, and increased markers of brain inflammation. Largely, with the exception of brain effects, the findings are similar to those observed after exposure to fine particles.

  (Ref: HEI (Jan 2013), Understanding the Health Effects of Ambient Ultrafine Particles, Health Effects Institute, Perspective 3, pp 1-5))

Sub attribute: displacement potential

Under main attribute: society

Definition: The potential of the technology to displace people (mainly tribals and those living in small villages) from their natural habitat or shelters

Weighting: 4.35

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	**Domestic coal:** In India, most tribes inhabit forest lands that are mineral rich; 90% of India's coals are found in tribal areas. Forest degradation due to mining in addition to other development projects has significantly depleted the ecosystem, rendering the tribal population more vulnerable socially and economically [1]. **Imported coal**: impacts of a coastal plant could be related to displacement of fishing villagers, salt-pan workers, animal grazers, and farmers, if at all. But even a high displacement scenario will mean significantly lower displacement than that for a domestic-coal-based plant as there no land is required for coal mining.
UCG	Social impacts may be minimal since, unlike surface mining, no major land acquisition or displacement is involved.
OCGT, CCGT	***Domestic gas***: large-scale displacement may be needed for gas drilling sites and laying pipeline infrastructure. However, the extent of displacement could be significantly lower than that for coal mines and coal power plants. Coal mining impacts are larger mainly because coal mines are located in areas that are usually more populated than gas field sites. ***Imported gas (LNG):*** Port infrastructure for imported gas may lead to displacement of coastal population. Displacement of people is also likely for pipeline infrastructure from re-gasification units to the end-use facility. However, the extent of cumulative displacement is significantly lower than that for coal-based generation.
RoR, Storage-based hydro, Pumped hydro	Considering 16 hydropower projects of NHPC covering commissioned power stations, under-construction projects, and proposed projects, it can be seen that number of *displaced* families per megawatt is only 0.26 whereas that of *affected* families is 0.66. [2]. Dam building is one of the most important causes for development-related displacement. Many of the dams have led to large-scale forced eviction of vulnerable groups. The situation of the tribal people is of special concern as they constitute 40%–50% of the displaced population. RoR projects generally create less social impacts whereas a storage-type HEP in a densely populated area can entail significant challenges related to resettlement and impacts on the livelihoods of downstream populations. The total displacement of people may be very much higher than that for coal-based technologies. [3].

Note

[1] CSE (2010). Rich lands, Poor People. Centre for Science and Environment

[2] Ministry of Power. http://powermin.nic.in/JSP_SERVLETS/jsp/Hydro_faq.htm#23
http://powermin.nic.in/JSP_SERVLETS/jsp/Hydro_faq.htm#23

[3] Cases: Sardar Sarovar dam has been called 'India's most controversial dam project'. Official figures indicate that about 42 000 families were displaced but non-governmental organizations such as the Narmada Bachao Andolan (NBA) puts the figure at about 85 000 families or 500 000 people. The Narmada Valley Development Project affected the lives of 25 million people who were in the valley and altered the ecology of an entire river basin.

(Ref: Lok Sabha Secretariat (2013). Displacement and Rehabilitation of People Due to Developmental Projects. Parliament Library and Reference, Research, Documentation and Information Service, No.30/RN/Ref./December/2013, pp 3)

Sub attribute: employment generation

Attribute: society

Definition: The potential of a technology to create employment through its life cycle (employment generation potential from the stage of resource extraction to final delivery of electricity at the generator bus bar

Weighting: 3.06

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	*Domestic coal:* according to CEA norms for manpower requirements for the 12th Plan construction phase: 8 people per megawatt, operation and maintenance: 1.1 people per megawatt; for coal mining (CIL): 888 people per MTPA (approximately 3.88 people per megawatt). CIL's policy: one job per two acres of land acquired for coal mining [1]. *Imported coal:* 1.5 people per megawatt (assumed). Less than that for domestic coal as coal mining is not involved. However, operational manpower requirements for IGCC may be higher considering the complexities of the technology	**OCGT, CCGT**	The total employment generation is assessed to be moderately lower than that for coal-based technologies, particularly domestic-coal-based technologies, as gas drilling and transport are less labour intensive. Even in terms of employment in plant operations, manpower requirement will be significantly less than that of a coal-based plant. LNG-based gas turbines may have even lower employment potential considering the absence of gas extraction. Between OCGT and CCGT, CCGT may have a marginally higher requirement of manpower considering the operational features.
UCG	Less than that for other coal technologies as coal mining is not involved. Operational requirements could be same as those of IGCC (imported coal)	**RoR, Storage-based hydro, Pumped hydro**	According to CEA norms for manpower requirements for the 12th Plan construction phase: 10 people per megawatt, O&M: 1.9 people per megawatt. [2]

[1] Prayas Energy Group (June 2012). Role of Thermal Power Plants and Coal Mining in Local Area Development and Addressing Regional Imbalance. pp 25

[2] Central Electricity Authority, http://www.cea.nic.in/more_upload/conclave/35.pdf

Sub attribute: cost of generation

Under main attribute: economy

Definition: Expected range of cost (Rs/kWh) of electricity ex-bus as estimated by a regulator

Weighting: 7.59

Supercritical PC	*Domestic coal:* Rs 2.1–2.6 /kWh *(Annexe 1: pp-xxiv)* *Imported coal:* Rs 3.3–3.7/kWh *(Annexe 1: pp-xxv)*	OCGT	*Domestic gas:* $4/mmbtu (Rs 3.3 /kWh) $8/mmbtu (Rs 5.8 /kWh) *(Annexe 1: pp-xxv)* *Imported LNG:* $10/mmbtu (Rs 7.1 /kWh) $16/mmbtu (Rs 11 /kWh) *(Annexe 1: pp-xxv)*
Supercritical CFBC	*Domestic coal:* Rs 2.3–2.8/kWh *(Annexe 1: pp-xxiv)* *Imported coal:* Rs 3.4–3.8/kWh *(Annexe 1: pp-xxv)*	CCGT	*Domestic gas:* $4/mmbtu (Rs 2.7 /kWh) $8/mmbtu (Rs 4.5 /kWh) *(Annexe 1: pp-xxv)* *Imported LNG:* $10/mmbtu (Rs 5.4 /kWh) $16/mmbtu (Rs 8 /kWh) *(Annexe 1: pp-xxv)*
Ultra supercritical PC	*Domestic coal:* expected to be marginally lower than that for supercritical PC *Imported coal:* Rs 3.2–3.6/kWh *(Annexe 1: pp-xxiv)*	RoR	Cost of generation may be marginally lower than that for storage-based hydro.
IGCC	*Domestic coal:* Rs 3-5/kWh (assumed) *Imported coal:* Rs 4-5/kWh *(Annexe 1: pp-xxv)*	Storage-based hydro	At an average CUF of 45%, the cost of generation is Rs 1.3–3.5/kWh *(Annexe 4)*
UCG	Rs 3.0 - 4.0 /kWh *(Annexe 1: pp-xxiv)*	Pumped hydro	Cost of generation is marginally higher than that of storage-based hydro.

Note:

- The cost of generation for coal-based technologies estimated based on the range of current market prices in respect of both domestically mined and imported coal.

Sub attribute: CAPEX

Under main attribute: economy

Definition: Expected range of capital costs (million rupees per megawatt) of the concerned technology

Weighting: 5.91

Supercritical PC	Rs 55–65 million/MW *(Annexe 1: pp-14-15, xxiv)*	**OCGT**	Rs 20–25 million/MW *(Annexe 1: pp-xxiv)*
Supercritical CFBC	Rs 65–80 million/MW *(Annexe 1: pp-26-27, xxiv)*	**CCGT**	Rs 40–45 million/MW *(Annexe 1: pp-91,98)*
Ultra supercritical PC	Rs 70–75 million/MW *(Annexe 1: pp-xxiv)*	**RoR**	Hydro project capital cost includes civil costs and E&M costs. Civil costs vary according to the type and site conditions of the plant. Civil costs are lower for RoR-based plants than for other hydro projects. E&M costs are similar for all technologies. Capital cost of power component: Rs 45–75 million/MW.
IGCC	Rs 100–200 million/MW *(Annexe 1: pp-37-39, 44, xxiv)*	**Storage-based hydro**	Civil costs are capital intensive for storage-based hydro depending on infrastructure requirements based on the site conditions including geological aspects and hydrological risks. E&M costs are the same as those for other technologies. Capital cost of power component: Rs 45–75 million/MW.
UCG	Rs 70–75 million/MW *(Annexe 1: pp-35, xxiv)*	**Pumped hydro**	Pumped storage plants are generally more expensive than conventional large hydropower schemes with storage [1].

[1] IRENA (June 2012). Renewable Energy Technologies: Cost Analysis Series. International Renewable Energy Agency, Volume 1: Power Sector, Issue 3/5, pp 9

Sub attribute: OPEX

Under main attribute: economy

Definition: Expected range of variable costs (million rupees per megawatt per year) of the concerned technology

Weighting: 6.13

Supercritical PC	Rs 1.5 million/MW/year *(Annexe 1: pp-14-15, xxiv)*	**OCGT**	Rs 1.5–2.0 million/MW/year *(Annexe 1: pp-xxiv)*
Supercritical CFBC	Rs 1.7–1.8 million/ MW/year *(Annexe 1: pp-26-27)*	**CCGT**	Rs 1.5–1.8 million/MW/year *(Annexe 1: p91,98)*
Ultra supercritical PC	Rs 1.5 million/MW/year *(Annexe 1: pp-14-15, xxiv)*	**RoR, storage-based hydro, pumped hydro**	O&M costs are low, generally 2.5% of the per kilowatt investment cost. [1] (approx 1.1-1..9 million/MW/year). Among the three technologies, OPEX costs of pumped hydro plants are marginally higher than those of storage-based plants, which, in turn, are marginally higher than those of RoR-based plants.
IGCC	Rs 2.3–2.8 million/MW/year *(Annexe 1: pp-37-39)*		
UCG	Site dependent *(Annexe 1: pp-35,xxiv)*		

[1] IRENA (June 2012). Renewable Energy Technologies: Cost Analysis Series. International Renewable Energy Agency, Volume 1: Power Sector, Issue 3/5, pp 24

Sub attribute: technology maturity

Under main attribute: technology

Definition: Current state of readiness of the technology in terms of its commercial availability

Weighting: 6.82

Supercritical PC	Mature both worldwide and in India. *(Annexe 1: pp-8-9)*	**OCGT**	Mature both worldwide and in India. *(Annexe 1: pp-86)*
Supercritical CFBC	Proven and few units commissioned. Lack of operational experience in India. *(Annexe 1: pp-26)*	**CCGT**	Mature both worldwide and in India. *(Annexe 1: pp-86)*
Ultra supercritical PC	Proven overseas; few operational plants. Boilers not yet developed for low-grade coals. *(Annexe 1: pp-xi)*	**RoR**	Mature and well advanced technology.
IGCC	Basic gasifier technology is mature, but suitable only for high-grade coal. Construction started for an 180 MW demonstration plant. *(Annexe 1: pp-42-43,44)*	**Storage-based hydro**	Mature and well advanced technology.
UCG	Technology demonstrated overseas but not in India. *(Annexe 1: pp-52,56-57)*	**Pumped hydro**	Mature and well advanced technology.

Note:

- USC PCs are expected to be at least 800 MW for a cost-economic design; 800 MW prototype boilers have not been developed so far for domestic coal because, given the low-grade coal, the boilers will be large. USC PC with imported coal is thus marginally more mature than USC PC with domestic coal.
- Basic gasifier technology used in IGCC comprises an entrained flow gasifier, which needs high-grade coal for hassle-free operation and is unsuitable for the low-grade coal available in India. Fluidized bed gasifiers for utility-size units, currently under development, are suitable for the coal available in India. Therefore, IGCC with imported coal is moderately mature than IGCC with domestic coal.

Sub attribute: net efficiency

Under main attribute: technology

Definition: Net efficiency is the ratio (percentage) of useful electricity output to total energy input (thermal + auxiliary energy) if any

Weighting: 7.05

Supercritical PC	***Domestic coal*:** 37% *(Annexe 1: pp-10, xxiv)* ***Imported coal*:** 38% *(Annexe 1: pp-10, xxv)*	OCGT	36%–39% *(Annexe 1: pp-xxiv)*
Supercritical CFBC	***Domestic coal*:** 37% *(Annexe 1: pp-2-3, xxiv)* ***Imported coal*:** 38% *(Annexe 1: pp-xxv)*	CCGT	54%–56% *(Annexe 1: pp-93)*
Ultra supercritical PC	***Domestic coal*:** Approx. 38%–40% (assumed) ***Imported coal*:** 41% *(Annexe 1: pp-xxiv)*	**RoR, storage-based hydro**	Best conversion efficiencies of all energy sources (around 90% water to electricity) *(Annexe 4)*
IGCC	37%–40% *(Annexe 1: pp-35)*		
UCG	47%–54% *(Annexe 1: pp-xxiv)*	**Pumped hydro**	Combined efficiency (generation as well as pumping mode) is around 70%–80% *(Annexe 4)*

Sub attribute: fuel flexibility

Under main attribute: technology

Definition: Ability to work with varying levels of fuel mix. For example, ability to run on coal blends of different strengths (varying proportions of domestic and imported coals in the mix) during plant life operation

Weighting: 4.78

Supercritical PC	Less flexible. Boilers are suitably designed and engineered according to coal characteristics: optimum (quality for which the boilers are designed), worst coal, best coal, and range of coal for the project to be considered for boiler design. Steam generator to be designed to give the guaranteed efficiency when fired with the coal having the characteristics for which the boiler was designed [1].	**OCGT, CCGT**	Gas turbines are normally designed for natural gas. Change of fuel can influence the flame characteristics and fluid kinetics inside the turbines and, unless these are factored into the operation, can potentially increase the downtime. Overall, these technologies can be considered equally flexible as compared to coal based technologies. *(Annexe 1: pp-90)*
Supercritical CFBC	CFBC boilers afford the maximum flexibility in fuel selection covering all coal types including domestic coal, international coal, and blended coal [2].		
Ultra supercritical PC	Less flexible. Technology not yet demonstrated for low-grade, high-ash coals. Development of CFBC for USC unit sizes is still far from the commercialization stage. *(Annexe 1: pp-xi)*		
IGCC	Matured entrained flow gasifiers are less flexible as they can use only high-grade, low-ash coals. Currently FBC gasifiers are proven only for small units but are very flexible if available in large, utility-scale units. Overall, very low fuel flexibility as compared to CFBC . *(Annexe 1: pp-29-30, xiii)*	**RoR, storage-based hydro, pumped hydro**	Water is the main resource required for hydropower generation. No fuel is required for operation. Therefore, fuel flexibility is not a concern in hydropower projects
UCG	Less flexibile. Typically, lignite and sub-bituminous coals are considered suitable for the process because of their volatile matter and moisture content. High-quality coals are less reactive and cannot be used for gasification. *(Annexe 1: pp-49)*		

[1] CEA (July 2013). Standard technical features of BTG system for supercritical 660/ 800 MW thermal units. Central Electricity Authority, pp 25

[2] James Utt, Robert Giglio (Oct 2012). Foster Wheeler's 660 MWe Supercritical CFBC Technology Provides Fuel Flexibility for Asian Power Markets. Foster Wheeler Global Power Group

Note:

- Although, CFBC can operate across a wide range of fuels, flexible fuel operation does have a marginal impact on boiler efficiency. A 2013 study modelled operations of a 40 TPH CFBC unit with two different coal grades: Indian coal of GCV 4300 kcal/kg and imported coal of GCV 5800 kcal/kg. The empirical data suggested that boiler efficiency with Indian coal was 77.51% and that with imported coal was 80.20%.
  (Ref.: Patel V K. (2013). Efficiency with different GCV of coal and efficiency improvement opportunity in boiler. *International Journal of Innovative Research in Science, Engineering and Technology,* 2, 1518–1527)

Sub attribute: infrastructure

Attribute: infrastructure

Definition: Built physical infrastructure: requirement of additional investments on rails, road, ports, etc.

Weighting: 5.77

Supercritical PC, supercritical CFBC, ultra supercritical PC	*Domestic coal:* Preferred location of plants are pitheads or interior locations (away from the coast). Infrastructural requirements usually high: development of coal mines, if the coal plant is within 50 km for coal transport, road upgrading for distances up to 200 km, railways upgrading including new tracks and rolling stock and supporting infrastructure for distances up to 2000 km; Water supply infrastructure for coal handling and cooling required *International coal:* preferred location of plants: coastal projects within 500 km of ports. Adequate coal unloading arrangement at ports to be ensured. All major and important minor ports should be mechanized by augmenting crane capacities, silos, conveyors, and wagon tipplers. Proper rail and road connectivity to power plants. Water supply infrastructure requirement are lower for coastal plants.	**OCGT, CCGT**	*Domestic gas:* infrastructure requirements lower than those for imported gas. Even then, high investments required. Pipelines need to be laid from well heads to end-use locations for transporting gas *Imported gas*: LNG requires high investments along the entire supply chain starting from piped transport of gas from well head to export port location, liquefaction at the LNG plant located at the exporting port, transfer through ships, regasification at the importing port, and piped transport to the end-use location.
IGCC	Infrastructure requirements similar to other coal-based technologies. Water infrastructure requirements may be lower as water consumption is two-thirds of those of comparable coal plants.	**RoR, storage-based hydro, pumped hydro**	Dependent on location of the hydropower plant. Remote locations may require critical infrastructure including roads, bridges and air connectivity to facilitate movement of men, machinery, and materials for construction. Overall dedicated infrastructure requirements can be assessed to be moderately less than those for coal.
UCG	Minimal infrastructure requirements since no coal mining or transport is involved. Requires drilling of boreholes for underground gasification. Infrastructure for water requirements. Infrastructure for pipeline transport of syngas from well heads to end-use stations to be developed.		

Note

- Hydro infrastructure though huge is at one location. In comparison, infrastructure requirements for coal are assessed to be even higher considering the need of roads, railways, specialized transporters, ports, water pipelines, etc.

Sub attribute: resource risk (price)

Under main attribute: policy risks

Definition: Potential risks arising from lack of control over international prices of coal and LNG. Risks arising from losing regulatory control over electricity costs due to pass-through of fuel costs.

Weighting: 4.55

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	***Domestic coal:*** domestic coal carries lower risks of price fluctuation as prices can be controlled. ***Imported coal:*** limited control over international coal prices and sea freight rates. Analysts believe that the hardening of coal prices in international markets may continue for a few more years until environmental concerns in northern Asia- Pacific region and US depress demand and lower prices. The cost of bulk transport of imported coal may increase due to increase in oil prices in the middle to long term owing to peaking of oil. This introduces an additional factor in the landed cost of imported coal. Growing resource nationalism is another concern that has to be factored in. Nations with rich mineral deposits are realizing the importance of depleting resources and are looking at national energy security and futures market [1].	**OCGT, CCGT**	***Domestic gas:*** domestic gas carries lower risks of price fluctuation as prices cab be regulated. ***Imported LNG:*** prices of imported gas are extremely volatile. LNG price in Asia is set as a percentage of the crude oil price. FOB prices will be lower but higher shipping cost will reduce the advantage. LNG will always be costlier than domestic gas. Landed cost of LNG may be approximately $17/mmbtu (which also factors in the cost of pipeline infrastructure).
UCG	Price risk same as that of domestic coal based capacities the absence of coal import and resource dependence. .	**RoR, storage-based hydro, pumped hydro**	Since no fuel resource is required for operation, there are no resource price risks for hydropower generation.

[1] WISE (2013), Future of coal electricity in India and sustainable alternatives, World Institute of Sustainable Energy, pp 33-36

Sub attribute: resource risk (availability)

Under main attribute: policy risks

Definitions: Potential risks from changes in international policies, lack of access to transport routes, resource-nationalistic polices by exporting countries, disruption of supply chain, resource capturing, etc.

Weighting: 5.83

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	*Domestic coal:* Domestic coal resources within our national control carry no risks related to availability.	**OCGT, CCGT**	**Domestic Gas**: Domestic gas resources within our national control carry no risks related to availability. **Imported gas:** Gas availability risks are assessed to be much higher than those from imported coal as LNG is available from limited locations, mostly from gulf countries, and there is very limited control over LNG supply chain. Transnational pipelines to import gas also face high geopolitical risks.
	Imported coal: there is sufficient potential for locating supplies in international markets for several decades. This however entails some medium-level risks [1]. Risks relate to the constraints on foreign acquisition of assets, international peaking of coal, and policy changes in other countries.	**RoR Storage based hydro, Pumped hydro**	Hydro resources within our national control carry no risks related to availability.
UCG	Lower risks. Availability of coal is dependent on the site selected for the projects.		

[1] WISE (2013), Future of coal electricity in India and sustainable alternatives, World Institute of Sustainable Energy, pp 33-36

Sub attribute: foreign exchange reserve risks

Under main attribute: policy risks

Definition: Potential for impact of technology on foreign exchange reserves exposure

Weighting: 3.94

Supercritical PC, supercritical CFBC, ultra supercritical PC, IGCC	***Domestic coal:*** reduced FE risks since no coal imports are involved. Foreign exchange risks associated with limited imports of some equipment and technologies. ***Imported coal:*** Higher FE impacts due to coal imports and technology imports .	OCGT, CCGT	***Domestic gas:*** *Higher technology import related risks as compared to domestic coal. No resource import related exposure.* ***Imported LNG:*** *Highest FE exposure due to resource and technology import*
UCG	In terms of FE drain, only technology import related risks; same as those from domestic coal based technologies	RoR, storage-based hydro, pumped hydro	Very low macroeconomic risks both on technology side and resource side. No import of resource is required for hydro generation.

Note

- Technology Import dependence appears to be very high for gas based technologies followed by coal based technologies and lowest for hydro technologies. Gas turbines up to 250MW rating are manufactured in India. For higher capacity gas turbines, imports are the only option. For coal based technologies, the technology import requirements are lower as compared to gas based technologies as many critical and non critical components are produced in India. In the case of hydro, as the major costs are related to civil infrastructure and not capital equipments, the import dependence risks for hydro technologies are assessed to be the lowest.

Results of Technology Assessment

The data and information from the sub-matrices were assessed to derive a preference score for each technology across each attribute. The preference score of each technology across each sub-attribute was multiplied with the sub-attribute weighting and summed to derive the final technology preference scores. **The detailed exercise covering the allocation of preference scores and calculating the final score are covered in Annexe 3.**

Based on the identified methodology, the technology priority scores and the priority order are shown in Table 11.

Table **11** Technology scores and first-order priorities

Scores	Rank	Technology priorities
34.88	1	Run of river hydro
38.25	2	Storage-based hydro
39.92	3	CCGT (Domestic gas)
40.09	4	Pumped hydro
42.26	5	Underground coal gasification (UCG)
42.34	6	OCGT (domestic gas)
45.27	7	CCGT(imported gas)
47.89	8	OCGT (imported gas)
49.13	9	CFBC supercritical (domestic coal)
49.50	10	CFBC supercritical (imported coal)
50	11	PC supercritical (domestic coal)
50.11	12	PC ultra supercritical (domestic coal)
50.23	13	PC supercritical (imported coal)
50.75	14	PC ultra supercritical (imported coal)
52.96	15	IGCC (imported coal)
53.64	16	IGCC (domestic coal)

Not surprisingly, hydro technologies emerge as the most preferred option, followed by gas-based technologies. Coal-based technologies, which are the mainstay power generation technologies, figure at the bottom of the ladder. But what is surprising is that, among the coal-based technologies, UCG seems to be the most preferred option, followed by CFBC supercritical and not PC supercritical.

UCG comes as a surprise preference mainly on account of lower environmental, social, climate, infrastructure, and cost impacts and lower policy risks as compared to other thermal technologies. CFBC-based supercritical technology seems to score over PC-based supercritical technology in terms of lower air pollution (particularly NOx and SOx) and fuel flexibility (CFBC boilers can accept variations in coal quality over a larger range). IGCC surprisingly appears at the bottom despite better environmental performance mainly because of high costs, low efficiency, and insufficient maturity.

Although this order of technology priorities considers all impacts (climate, environment, society, techno-economics) and implications (technology, policy risks), it does not consider generation flexibility, which is a key consideration for the study. It is worth noting that all of these technologies can provide baseload support but from the perspective of the study, technologies that can provide generation flexibility could be even more valuable for power sector planning.

The next chapter re-assesses the technologies priorities based on generation flexibility.

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CHAPTER 5

GENERATION FLEXIBILITY MATRIX AND SECOND ORDER OF PRIORITIES

5

GENERATION FLEXIBILITY MATRIX AND SECOND ORDER OF PRIORITIES

Generation flexibility refers to the operation of power-generating units at varying load levels, including minimum load operation, load following, and efficiency at low loads, in response to changes in system load requirements. Generation flexibility of resource technology choices will be the key to designing an electricity system in the future. Considering this, the study considers generation flexibility of technologies separately and loads it on the first order of priority to determine transition technology priorities. The main sub-attributes considered under generation flexibility are as follows: ramp rate, part load efficiency, lower limit of technical operation, cycling ability, and the cost of ramping.

Based on the methodology, the priorities derived from the generation flexibility attribute are compared with the order of priorities derived from the TA matrix to arrive at the final order of technology priorities.

Ramp Rates

Ramp rate is defined as the rate at which a technology can vary its generation within its technical operating range. The maximum ramping rate is specific to plant design and is also a function of plant capacity. It is measured in megawatts per minute or as a percentage of rated capacity per minute.

Coal plants respond to changes in load demands by increasing or decreasing generation, but these changes are limited by a set of economic and technology factors. Gas turbine technologies, on the other hand, have lower inertia and act faster than coal-based technologies. However, hydro technologies exhibit highest ramp rates, providing comparable generation variation in seconds rather than in minutes.

Although ramp rates vary across different operating capacity ranges, the important comparative aspect is the ramp rate in the acceptable operating range of the technology, usually between 50%–90% and 90%–100%. The following sub-matrix shows the indicated ramp rates of the technologies under consideration.

Supercritical PC	30%–50% : 2%–3%/min 50%–90 % : 4%–8%/min 90%–100% : 3%–5%/min *(Ref: Annexe 1, pp-105)*	OCGT	Ramp rates of OCGT are marginally higher by inherent design. Typical range is 8%–12%/min. *(Ref: Annexe 1, pp-105)*
Supercritical CFBC	Could be marginally lower than a PC-based unit considering the difference in the burning characteristics. The ultrafine coal particles (around 200 μm) in the PC boiler provide a larger surface area for more efficient combustion compared to the larger coal particles (typically 6 mm) in CFB boilers. *(Ref: Annexe 1, pp-105)*	CCGT	40%– 85% : 4%–8%/min 85%–100% : 2%–3%/min The gas turbine responds to load requirements faster and it is loaded up to its baseload, whereas in the steam turbine by means of attemperators, bypass follows the load requirements at a slower rate. *(Ref: Annexe 1, pp-105)*
Ultra supercritical PC	The ultra supercritical PF units are expected to have marginally lower ramp rates than their supercritical peers in view of the more sensitive metallurgy in the former. Problems associated with dissimilar metal welds and the possibility of thermal stresses on turbine blades	**RoR, storage-based, and pumped hydro**	• Small units (10–59 MW): 1%–6% per second • 60 MW and above 4%–6% per second In case of RoR and pumped hydro, sustained and continuous load requirement will limit their flexibility characteristics to the available head,

	would typically mandate lower OEM recommendations for the ramp rate. *(Ref: Annexe 1, pp-105)*
IGCC	50%–100% : 1%–3%/min The main bottleneck in IGCC ramping is the air separation unit used in entrained flow operations. For FBC-based operations, the gasification unit will be more sluggish than the turbines. *(Ref: Annexe 1, pp-104)*
UCG	UCG operation is similar to CCGT operation except for the use of syngas, which may have higher hydrogen content. Combustion of syngas can result in problems related to flame instability and faster combustion dynamics that have greater potential to damage turbine components. The expected ramp rates may be lower than those for CCGT but higher than those for IGCC*(Ref: Annexe 1, pp-108)*

	because they have lower storage capacity than reservoir storage. In low-head units, ramp rates are limited by L/H ratio (length of penstock to head ratio) because the flow rates designed for the penstock could be lower than what is required to reach the mechanical limit of the turbine. *(Ref: MWH (Aug 2009), Technical analysis of pumped storage and integration with wind power in the Pacific Northwest, pp. 3–10)*

Notes

- Information on ramp rates and other related operational details on supercritical CFBC, ultra supercritical PC, and UCG is limited to qualitative aspects in the absence of ready empirical data.
- Gas turbines firing syngas typically require about 3–7 times fuel flow to produce the same turbine inlet temperature. This may make them more efficient but also imposes surge margin restrictions that can limit the capacity.
- Hydro technology ramp rates indicated are for low- or medium-head units for all the three technologies. This is based on the assumption that high-head hydro units (limited to north-eastern India) will not be implemented in foreseeable future.
- Amongst coal technologies, UCG is expected to exhibit best ramping rates.

Part Load Efficiency

Part load efficiency is defined as the efficiency at 60% load expressed as a percentage of efficiency at 100% load. Backing down of conventional power plants in a low-load-demand or high-supply scenario would result in lower efficiencies. Part-load efficiencies of various technologies can indicate the suitability of a given technology for part-load operation in response to system demands. Part-load efficiency depends on the efficiency in operation of pulverizer mills, fans, feed pumps, boiler and turbine valves, etc.

The matrix below captures the drop in efficiency (with respect to efficiency at 100% load) at different operating loads.

Supercritical PC, supercritical CFBC, and ultra supercritical PC	80% : 1.5 60% : 4 40% : 6 *(Ref: Annexe 1, pp-106)*	**OCGT**	80% : 4 60% : 7–10 40% : 14–16 *(Ref: Annexe 1, pp-106)*
		CCGT	80% : 3 60% : 6–8 40% : 12–14 *(Ref: Annexe 1, pp-106)*
IGCC	80% : 4 60%: 8–10 *(Ref: Annexe 1, pp-106)*	**RoR, storage-based**	Reaction turbine 40% : 11 60% : 5 80% : 2 *(Ref: AHEC (May 2011), Selection of Turbine and Governing System for Hydroelectric Projects, Alternate Hydro Energy Center, Page 25)*
UCG	No data on part-load efficiency are available since no modern UCG-based plants are in operation. However, since these are primarily CCGTs firing syngas, their part-load efficiencies are assumed to marginally lower than those of natural-gas-fired CCGTs. *(Ref: Annexe 1, pp-108)*	**Pumped hydro**	80% : 3 (variable speed) 4 (single speed) 60% : 7 (variable speed) 10 (single speed) 40% : 13 (variable speed) 19 (single speed) *(Ref: MWH (Aug 2009), Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest, , pp. 2–13)*

Notes

- Although part-load operation of CFBC units is expected to be higher than that of PC-based units, the higher auxiliary consumption CFBC units may mitigate this advantage, making PC and CFBC nearly similar in terms of part-load efficiencies.
- Part-load efficiencies for conventional hydro plants are derived from load efficiency curves for Francis turbines.

Lower limit of technical operation

The lowest possible load (as a percentage of full load) at which the technology can work without auxiliary support.

Low-load operation is defined as the lowest safe and reliable plant operation without use of supplementary firing units, and for coal units is typically 35%–40% of full load capacity. (Ref: EPRI (June 2009) Low Load/Low Air Flow Optimum Control Applications, by Electric Power Research Institute. Section 3-9).

Technologies that can run stably at lower loads are at an advantage because they can offer higher flexibility by being able to operate at a wider operating capacity range and, consequently, offer better generation support. A low-load operation is desirable because it gives more flexibility without incurring additional costs and equipment damage associated with complete shutdowns and subsequent start-ups. However, operating at low loads compromises on emissions and efficiency.

The following matrix captures the assessed lower load limit (as a percentage of full load) for the technologies under consideration.

Supercritical PC and ultra supercritical PC	25%–40% *(Ref: Annexe 1, pp-110)*	**OCGT**	10% *(Ref: Annexe 1, pp-110)*
Supercritical CFBC	40% *(Ref: Annexe 1, pp-110)*	**CCGT**	25% *(Ref: Annexe 1, pp-110)*
IGCC	50% *(Ref: Annexe 1, pp-110)*	**RoR and storage-based**	For Francis turbines, it is expected to be 30%–60% *(Ref: AHEC (May 2011), Selection of Turbine and Governing System for Hydroelectric Projects, Alternate Hydro Energy Center, Page 5)*
UCG	50% *(Ref: Annexe 1, pp-110)*	**Pumped Hydro**	Variable speed units can be used for generation at 40%–100% load. Single-speed units operate at 60%–100%. *(Ref: MWH (Aug 2009), Technical analysis of pumped storage and integration with wind power in the Pacific Northwest, , pp. 2–13)*

Notes:

- Typically, PC-based units – both subcritical and supercritical – are stable down to 40%. When the fuel quality deteriorates with volatiles, the operational window is narrowed, that is the minimum stable load that the boiler can sustain goes up. In extreme cases, as with anthracite coals, the typical minimum stable load is about 60%.
- Between PC and CFBC technologies, when fuel quality deteriorates, CFBC boilers have a marginal advantage over PC; the former can sustain a marginally lower load than the latter. However, the practical significance of this advantage will be felt only for fuels with very low volatiles for sustained operation.
- IGCCs are typically meant for baseload operation in view of the low ramping gradient. Besides, below 60%, more CO is formed. However, the technical minimum load is 50%.
- Since UCG-based GTs are also operating with syngas, these will probably have performance features similar to those of IGCC with respect to the minimum load, considering the aspects related to combustion dynamics and flame stability.

  (Ref: Annexe 1, Page)
- Francis turbines operating below the lower designed limit will experience cavitation and vibration problems.

Cycling Ability

Cycling ability is defined as the ability of the technology to accept cycling loads without significant material damage and deterioration in performance. This characteristic determines the ability of a technology to undergo frequent ramping with limited damage.

Majority of the conventional technologies are typically designed for baseload operation; they are not designed to handle fluctuating loads. Under cyclic operations, the technologies are subjected to damage and fatigue because of differences in temperature and pressure in most sections in the steam cycle. This damage is measured in terms of the costs of repairs and maintenance. The ability to sustain this damage and fatigue varies with the technology and is based on its inherent operating conditions.

In thermal technologies, technology capability for cycling is limited by thermal stresses, creep stresses, fatigue, and flue gas deposits corroding the parts. In gas-based units, repeated cycling causes stresses on turbine blades, sintering of HRSG tubes, and erosion and corrosion of nozzle vanes. In hydro power units, repeated cycling damages the housing and support equipment.

Supercritical PC	Supercritical units face wear and tear of equipment in the boiler and turbine islands due to cycling operation. Furnace distortion, superheater and re-heater failures at weld sections (due to dissimilar metal welds), refractory failures, and thermal-induced fatigue of economizers are common problems in boiler sections. Turbine section failures include thermal fatigue on blades due to steam temperature mismatch, fatigue-induced cracking, and erosion of blade and nozzle blocks. *(Ref: Annexe 1, pp-108)*	**OCGT**	Highest cycling ability amongst all thermal technologies. Major problems related to cycling occur because of thermal stresses induced in the turbine rotor, corrosion of nozzle vanes, thermal quench of headers, and slow response of feed water systems. *(Ref: Annexe 1, pp-108)*
Supercritical CFBC	Cycling ability of CFBC units is marginally lower than that of PC units. Larger fuel particles in CFBC require more time for combustion. Cyclic operation results in incomplete combustion, which leads to corrosion of equipment. *(Ref: Annexe 1, pp-108)*	**CCGT**	CCGT plants are marginally less suitable for cycling load than OCGT because of the combined cycle operation. High stresses from uneven flows of HRSG tubes, tube failures from thermal differentials, and flow-assisted corrosion of carbon steel tubes of feed water systems are common effects of cycling. *(Ref: Annexe 1, pp-108)*
Ultra supercritical PC	Since USC PCs employ austenitic and duplex steels, there are complex metal interfaces that may make the technology prone to thermal stresses and fatigue stresses. It is expected that USC technology vendors will recommend tight operational and load control, making USC less suitable than supercritical units for cycling. *(Ref: Annexe 1, pp-108)*	**RoR, storage-based, pumped hydro**	The highest cycling ability as there are no fuel input restrictions. RoR-based units could experience clogging of nozzles because of silt during cycling operations. For pumped storage, single-speed pumping units exhibit cycling abilities similar to those of conventional hydro units. Wear and tear are associated with damage to the mechanical equipment, namely turbine rotors, vanes, support structures, and nozzle (in the case of RoR). Pumped storage units may be damaged during pumping operations owing to higher or lower cycling requirements. Adjustable-speed machines can provide frequency control in both generating and pumping modes. With an adjustable-speed machine, the response is faster than that with a conventional unit under speed governor control. *(Ref: MWH (Aug 2009), Technical analysis of pumped storage and integration with wind power in the Pacific Northwest, pp. 2–6)*
IGCC	The cycling capabilities of IGCC units are expected to be the least suitable for cycling amongst the thermal technologies under consideration IGCC operates in a stand-alone manner with all three major components– ASU, gasifier and clean up as well as the power block - integrated to each other. The flexibility of the IGCC unit would depend on the ramp up rate of the ASU (1- 3 %). In view of this, IGCC units are inherently not suitable for cycling.. *(Ref: Annexe 1, pp-108-109)*		
UCG	Since a number of UCG wells normally support a power unit, in general, a UCG based unit can operate like a combined cycle unit since the gas pooled from multiple wells can be fed to the power block. UCG exhibits the best cycling ability amongst all the coal-based		

	technologies considered. However, considering the difficulties in burning syngas as compared to natural gas, limits would be imposed by the increased risk of thermal stress due to the high hydrogen content of the fuel. This would make UCG moderately less flexible than gas turbines. *(Ref: Annexe 1, pp-108-109)*		

Notes

- Although the impacts of cycling are felt both on the boiler island and the turbine island, it is felt that failures in turbine island, particularly damage to turbine blades due to thermal stress or creep, are more critical than failures in the boiler island.
- Steam cycle operation of supercritical CFBC units is the same as that of PC. The residence time for fuel combustion is higher in the case of CFBC. Incomplete combustion during cycling operation could lead to slagging and fouling of equipment because fuel particles in CFBC are larger than those in PC.

Incremental cost of ramping

Incremental cost of ramping is mainly seen as fluctuations in fuel costs and O&M costs due to ramping of the unit. In addition to technical limitations, generation flexibility has economic implications ranging from increased fuel costs (due to lower efficiencies) to increased operational expenses (due to wear and tear). These economic implications are very important to the acceptability and feasibility of operating conventional technologies on the variable generation mode. Although fixed costs comprise the largest share of total commercial costs, the present study only considers real costs associated with increased fuel and operations costs.

While increased direct incremental costs of fuel owing to cyclic operation are easy to estimate, costs of damage to the power plant equipment and of the consequent downtime due to cyclic operation are more difficult to estimate. Based on available studies, the costs associated with wear and tear (due to cycling operation) of a 1000 MW plant were estimated in Indian context for daily cycling (ref: Annexe 1: - pp. 111-114), the related fuel costs and expected operations costs were assumed.

For cost comparisons, the costs for thermal units are measured in terms of the percentage increase in O&M (or in that of the fixed costs) and in terms of the percentage increase in fuel cost. Costs for hydro technologies are represented in terms of cost per megawatt for start-up or shutdown.

Supercritical PC and ultra supercritical PC	O&M and start-up fuel cost: the incremental annualized O&M cost attributable to cycling could be Rs 1300–1900 million for a 1000 MW unit across the current price of domestic and imported coal. The costs for USC plants are expected to be marginally higher given the higher probability of metallurgical damages due to incremental generation. *(Ref: Annexe 1, pp-111)*	**OCGT CCGT**	The costs of daily cycling in respect of both OCGT and CCGT are found to be about Rs 800 million for a 1000 MW plant. In case of both OCGT and CCGT, since the start-up time required is far less than that for coal-based units, the start-up fuel requirement is only marginal and hence the fuel cost is not a big influence on the cost of cycling. *(Ref: Annexe 1, pp-113)*

Supercritical CFBC	The costs for CFBC are expected to be fairly close but marginally higher than those for PC-based units given the marginally lower ramping rates for typical CFBC units.	**RoR, storage-based**	The high part-load efficiency and ramp rates coupled with higher cycling ability would make the incremental cost for hydro significantly lower than that for other combustion-based technologies.
IGCC	Cycling costs of IGCC may be significantly more than that of other coal-based technologies considering the lower part-load efficiencies and technical difficulties associated with ASU (air separation units) and gasification units. *(Ref: Annexe 1, pp-115)*		
UCG	For UCG-based units, the cost of cycling is expected to be marginally higher than that for identically rated CCGT units, at least initially since research on the behaviour of syngas is still in progress. *(Ref: Annexe 1, pp-111)*	**Pumped hydro**	Constant-speed pumped storage units may be damaged during pumping operation and there may be increased wear and tear even in variable-speed turbines resulting in moderately higher O&M costs than those for RoR and storage schemes. However, even then, the costs are expected to be significantly lower than those for other combustion-based technologies

Summary and conclusion

All the coal-based technologies under consideration have inferior flexibility capabilities as compared to gas-based technologies except perhaps UCG, which works on the combined cycle mode, similar to CCGT units. However, complexities associated with syngas combustion suggest that UCG would be a slightly inferior choice to gas turbines. Among the dominant coal-based technologies, supercritical PC units operating in the sliding pressure mode seem to exhibit best flexibility characteristics amongst PC units. CFBC units appear to have slightly inferior ramping capabilities to that of PC units but do exhibit marginally higher part-load efficiencies. PC ultrasupercritical could also provide wider flexibility if the current challenges related to metallurgy are met. The least preferable option from a generation flexibility perspective appears to be IGCC technology. Although some reports suggest good ramping characteristics of IGCC because of its combined cycle mode of operation, the study assessment suggests that actual bottlenecks would be the gasification and air separation processes.

It has to be noted that these technology priorities are resource-neutral in the sense that the type of resource used (domestic or imported) does not affect the generation flexibility of the technology. Based on the above considerations, the ideal technology priorities from a generation flexibility perspective are captured in Table 12.

Table **12** Technology priorities (with generation flexibility)

Technology priorities (generation flexibility)	
Rank	**Technology priority**
1	Run-of-river hydro (pondage)
1	Storage-based hydro
2	Pumped hydro
3	OCGT (domestic gas)
3	OCGT (imported gas)
4	CCGT (domestic gas)
4	CCGT (imported gas)
5	Underground coal gasification (UCG)
6	PC supercritical (domestic coal)
6	PC supercritical (imported coal)
7	CFBC supercritical (domestic coal)
7	CFBC supercritical (imported coal)
8	PC ultra supercritical (domestic coal)
8	PC ultra supercritical (imported coal)
9	IGCC (imported coal)
9	IGCC (domestic coal)

If we compare this order of priorities with the first order of technology priorities derived from the technology assessment exercise, it appears that the both the orders appear nearly similar, with hydro technologies at the top followed by gas-based technologies and coal-based technologies. Table 13 compares the two orders of priority.

Table **13** Technology priority orders (with and without generation flexibility)

Technology priorities (without generation flexibility)		**Technology priorities (with generation flexibility)**	
Rank	**Technology**	**Rank**	**Technology**
1	Run-of-river hydro (pondage)	1	Run-of-river hydro (pondage)
2	Storage-based hydro	1	Storage-based hydro
3	CCGT (domestic gas)	2	Pumped hydro
4	Pumped hydro	3	OCGT (domestic gas)
5	Underground coal gasification (UCG)	3	OCGT (imported gas)
6	OCGT (domestic gas)	4	CCGT (domestic gas)
7	CCGT (imported gas)	4	CCGT (imported gas)
8	OCGT (imported gas)	5	Underground coal gasification (UCG)
9	CFBC supercritical (domestic coal)	6	PC supercritical (domestic coal)
10	CFBC supercritical (imported coal)	6	PC supercritical (imported coal)
11	PC supercritical (domestic coal)	7	CFBC supercritical (domestic coal)
12	PC ultra supercritical (domestic coal)	7	CFBC supercritical (imported coal)
13	PC supercritical (imported coal)	8	PC ultra supercritical (domestic coal)
14	PC ultra supercritical (imported coal)	8	PC ultra supercritical (imported coal)
15	IGCC (imported coal)	9	IGCC (imported coal)
16	IGCC (domestic coal)	9	IGCC (domestic coal)

As the order of priorities, with or without considering generation flexibility, is nearly similar, integrating the generation flexibility priorities into the first order of priorities to derive transition technology priorities can be done by using a simple narrative-logic-based argument. RoR, which emerges at the top in both the order of priorities, appears to be the most desirable transition technology, followed by storage-based hydro. Pumped storage hydro, which emerges as the fourth option in the first order of priorities and second option in generation-flexibility-based priorities, emerges as the next best choice after storage-based hydro.

A simple ranking-based assessment would suggest CCGT (domestic gas) could be the fourth best transition technology choice followed by OCGT (domestic gas). UCG, which is the fifth best choice across both the orders of priorities, is a clear candidate for the sixth slot, followed by CCGT (imported gas) and OCGT (imported gas).

Among the other coal-based technologies, considering the relative rankings of CFBC supercritical compared to PC supercritical, CFBC supercritical (domestic coal) seems to be a marginally better choice with an average ranking of eight than PC supercritical (domestic coal). Based on similar logic, the final order of transition technology priorities is shown in Table 14.

Table **14** Derivation of transition technology priorities

Technology priorities (Without generation flexibility)		Technology priorities (with generation flexibility)		Transition technology priorities (with generation flexibility)	
Rank	**Technology**	**Rank**	**Technology**	**Rank**	**Technology**
1	Run of River hydro (pondage)	1	Run-of-river hydro (pondage)	1	Run-of-river hydro (pondage)
2	Storage-based hydro	1	Storage-based hydro	2	Storage-based hydro
3	CCGT (domestic gas)	2	Pumped hydro	3	Pumped hydro
4	Pumped hydro	3	OCGT (Domestic gas)	4	CCGT (domestic gas)
5	Underground coal Gasification (UCG)	3	OCGT (imported gas)	5	OCGT (domestic gas)
6	OCGT (domestic gas)	4	CCGT (domestic gas)	6	Underground coal gasification (UCG)
7	CCGT(imported gas)	4	CCGT(imported gas)	7	CCGT(imported gas)
8	OCGT (imported gas)	5	Underground coal gasification (UCG)	8	OCGT (imported gas)
9	CFBC supercritical (domestic coal)	6	PC supercritical (domestic coal)	9	CFBC supercritical (domestic coal)
10	CFBC supercritical (imported coal)	6	PC supercritical (imported coal)	10	PC supercritical (domestic coal)
11	PC supercritical (domestic coal)	7	CFBC supercritical (domestic coal)	11	CFBC supercritical (imported coal)
12	PC Ultra supercritical (domestic coal)	7	CFBC supercritical (imported coal)	12	PC supercritical (imported coal)
13	PC supercritical (imported coal)	8	PC Ultra supercritical (domestic coal)	13	PC Ultra supercritical (domestic coal)
14	PC Ultra supercritical (imported coal)	8	PC Ultra supercritical (imported coal)	14	PC Ultra supercritical (imported coal)
15	IGCC (imported coal)	9	IGCC (imported coal)	15	IGCC (imported coal)
16	IGCC (domestic coal)	9	IGCC (domestic coal)	16	IGCC (domestic coal)

The transition technology choices derived in Table 13 represent ideal technology choices that are not only more climate- and environment-friendly but also significantly more valuable for their ability to provide flexible support, baseload as well as peak load support. However, it has to be noted that the these ideal choices have been derived without considering resource constraints (the size of resources and possible depletion) or other implementation constraints and therefore to integrate these ideal choices into actual planning would require a thorough analysis of the possible resource and implementation constraints facing real-world technology choices. The next chapter tries to assess these constraints and challenges.

CHAPTER 6

INTEGRATING TRANSITION TECHNOLOGY CHOICES IN IMPLEMENTATION PLANS

6

INTEGRATING TRANSITION TECHNOLOGY CHOICES IN IMPLEMENTATION PLANS

The transition technology priorities derived in Chapter 5 represent an order of choices that is both sustainable and optimal. But these transition technology priorities essentially represent ideal technology choices that do not consider practical constraints related to resources, social opposition, environmental constraints, technological/commercial challenges, etc.

Given this background, integrating the transition technology choices in implementation planning would require a thorough understanding of the myriad challenges hindering implementation of these ideal technology choices. This in turn would require a detailed understanding of our past achievements related to adding generation capacity. The following section is a brief overview of our past record and future options in generation planning and implementation.

Generation planning: past performance and future choices

The most effective way to understand and assess the practical constraints to capacity addition is to compare the targets set for each technology and actual achievements; Table 15 compares these figures for the last three five-year plans.

Table **15** Shortfall in meeting targets for capacity additions (MW) in 9th, 10th and 11th five-year plans, by technology

Five-year Plan		Hydro Power	Thermal		
			Coal	Gas	Total
9th	Planned[b]	9820	18818		
	Achieved[a]	4611	7977	4601	12578
10th	Planned[b]	14393	28328		
	Achieved[a]	8385	8990	2529	11519
11th	Planned[c]	15627	52850	6843	59693
	Achieved[a]	4336	40901	4689	45590

[a]Growth of Electricity Sector in India from 1947-2013, CEA, p. 8
[b]Annual Report 2001-02, Ministry of Power, Chapter 2, p. 4
[c]11th Plan Capacity Addition, CEA, p. 1

Table 15 shows that in the 11th Five-Year Plan, actual achievements fell short of the targets by 22% in the case of coal, 31% in the case of gas, 72% in the case of hydro power. While the shortfall in coal-based capacities was mainly on account of contractual delays, shortage of power equipment, and coal availability, logistical challenges related to coal transport, particularly rail transport, are other factors that have hampered accelerated development of this sector. (Ref: Planning Commission (Jan 2012). Report of the Working Group on Power for Twelfth Plan (2012-17), Chapter 1, pp 1-5).

In the gas sector, the problems are more obvious. Gas availability and gas prices seem to be the biggest challenges facing this sector. Although constraints in the availability of domestic gas can be overcome by importing LNG, the landed price structure and contractual clauses with LNG supply for power or fertilizer sectors seem economically unviable. The prospective increase in the domestic gas prices is expected to affect economic viability of gas-based generation even more adversely for the short to medium term. (Ref: Annexe 2: Gas Resource Assessment Report)

The huge shortfall in hydro capacity additions, on the other hand, is mainly on account of contractual delays, rehabilitation and resettlement (R&R) issues, delays in environmental clearances, and technical and geological complexities.

Surprisingly, if we consider the proposed capacity additions for the 12th and the 13th plans as worked out in the National Electricity Plan 2012 (CEA (Jan 2012), National Electricity Plan 2012, Central Electricity Authority, Vol 1, Generation), it appears that hydro capacity has been capped at 9204 MW and 12 000 MW in the 12th and the 13th plans as against a total capacity addition of 98 190 MW and 109 700 MW, respectively, in the base-case scenario (Low Gas Low RE Scenario).

Even an alternative 'optimistic' scenario, namely 'High Gas High RE', visualizes no changes in the proposed hydro capacity addition but instead assumes gas-based capacity additions of about 13 000 MW during the 12th and the 13th plans.

Table 16 presents the estimated capacity additions, by technology, during the 12th and 13th plans for two scenarios, namely 'Low RE Low Gas' (LREG) and 'High RE High Gas' (HREG).

Table **16** Projected coal-based capacity (**MW**) for two scenarios

Scenario 1: Low RE Low Gas		
Fuel	12th Five-Year Plan (2012–2017)	13th Five-Year Plan (2017–2022)
Coal	66600	49200
Hydro	9204	12000
Gas	1086	0
Others (RE and nuclear)	21300	48500
Total	98190	109700
Scenario 3 : High RE High Gas		
Fuel	12th Five-Year Plan (2012–2017)	13th Five-Year Plan (2017–2022)
Coal	51400	34000
Hydro	9204	12000
Gas	13086	13000
Others (RE and nuclear)	32800	63000
Total	106490	122000

Across both the contrasting scenarios, the suggested implementation choices (based on the projected capacity additions for each technology) seem to be the opposite of the ideal (transition technology) choice in terms of priorities. Interestingly, though, this mismatch does not stem from system modelling but from practical constraints that force us to curtail choices. In this context, it is important to thoroughly analyse these practical constraints and their impacts on past capacity additions and slippages.

Assessment of implementation constraints

Whereas gas-based capacities have been stranded predominantly for obvious reasons, the main implementation constraints to coal-based generation and hydro power projects stem from myriad issues.

Based on an analysis of the report by CEA, namely (Ref: Status of Hydro Electric Projects under execution for 12th Plan & beyond as on 31.03.2014: *www.cea.nic.in/ reports/ proj_mon / status_he_execution.pdf*), Table 17 gives a breakdown of stranded projects by the identified causes of delay. Technological and geological issues mainly relate to site-specific technological challenges or design modifications necessitated by geological surprises, and delays related to R&R issues are mainly due to public or local resistance. Environmental issues are identified as those related to environmental approvals from designated authorities; contractual delays are mainly assumed to arise from non-compliance with contractual obligation, availability of labour, contract cost escalation, etc.; and 'Others' mostly includes delays due to floods or other natural or man-made disasters.

Table **17** Reasons for slippages of hydro projects

No.	Project	State	Capacity (MW)	Technical/ Geological	R&R	Environmental	Contractual	Others
1	Uri 2	J&K	240	√	√			
2	Kishanganga	J&K	330		√			
3	Parbati 2	HP	800		√		√	
4	Parbati 3	HP	520				√	
5	Kol	HP	800	√		√		
6	Rampur	HP	412	√				
7	Tapovan Vishnugad	UKND	520	√			√	√
8	Teesta 4	WB	160	√	√		√	
9	Subansiri Lower	ArP	2000	√	√		√	
10	Kameng	ArP	600	√			√	√
11	Pare	ArP	110	√	√			√
12	Baglihar 2	J&K	450	√				
13	Uhl 3	HP	100				√	
14	Sainj	HP	100	√				
15	kashang 2&3	HP	130		√			
16	Swara Kuddu	HP	111	√				
17	Lower Jurala	AP	240		√		√	√
18	Pulichintala	AP	120				√	
19	Sorang	HP	100	√				
20	Tidong 1	HP	100		√			
21	Shrinagar	UKND	330		√	√		√
22	Maheshwar	M.P.	400		√			√
23	Teesta 3	SKM	1200					√
24	Teesta 6	SKM	500	√	√		√	
25	Rangit 4	SKM	120	√				√
26	Tehri PSS	UKND	1000	√	√		√	
27	Lata Tapovan	UKND	171					√
28	Subanshri Lower	ArP	2000		√			
29	Shongtong Karcham	HP	450					√
		Total capacity	**14114**	**5493**	**8340**	**1130**	**6731**	**4141**
		Total	**29**	**11**	**14**	**2**	**11**	**10**
		Average stranded capacity, MW	**486.68**	**499.4**	**595.7**	**565**	**611.9**	**414.1**

(Source: CEA)

It is clear from Table 17 that out of 29 projects of 100 MW and above, 11 large projects with a total capacity of 6731 MW have been delayed because of contractual issues; 8340 MW is stranded because of R&R; and 2 large projects (Kol 800 MW and Shrinagar 330 MW) await environmental approvals. Surprisingly, technical constraints or geological surprises have affected only 5493 MW out of the total stranded capacity of 14 114 MW. Assessment for slippages in coal-based capacity is expected to yield a similar picture.

Interestingly, this suggests that if a few selected constraints (system-dependent constraints) are removed, the emerging picture will be far better. In the case of hydro (Table 10), if contractual and R&R-related constraints are overcome, about 4100 MW can be brought on-stream in short to medium term. Effective project management strategies to address delays resulting from geological surprises and design changes can free even more stranded capacity for implementation.

However, if we go back to the targets for capacity additions set for each technology, it appears that accumulated experience with these implementation constraints has perhaps given rise to the notion that most of these constraints cannot be overcome and we essentially have to make our choices after factoring in these constraints. While this notion will be true if we follow a business-as-usual path, a change in the approach to managing these implementation constraints can make a great deal of difference. Figure 2 suggests that although current implementation choices and ideal (transition) choices may diverge, the gap between them can be bridged by adopting a different route.

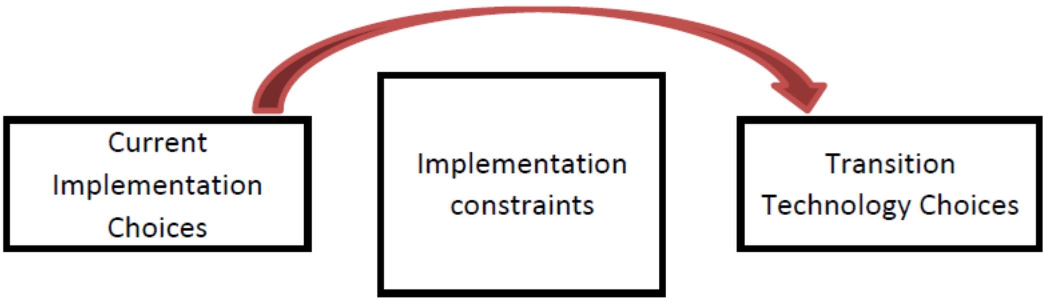

Figure **2** The distance between current choices and transition technology choices

The insights generated from the study suggest that all that is needed is a different approach to managing technologies, projects, and implementation challenges. However, such a change in approach would require an overhaul of our established systems of evaluation and planning—a shift to a completely different paradigm.

Some of the aspects and action points emanating from this paradigm shift are covered in the next chapter.

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CHAPTER 7

EMERGING POLICY THEMES AND WAY FORWARD

7

EMERGING POLICY THEMES AND WAY FORWARD

The analysis in the previous chapter suggests that the chasm between our current generation choices and the desirable technologies is a result of the challenges facing the power sector today (R&R issues, environmental clearances, contractual delays, etc.). Surmounting these challenges would require a different paradigm for technology evaluation, project appraisal, and capacity planning that goes beyond mere cost comparisons and unlocks the significant values (non-monetized values) associated with the transition technology choices.

These findings and other findings derived from the study methodology and interim analysis yield very interesting insights, which form the policy themes identified in the study. The possible action items emanating from these themes form the basis of the study's recommendations. Some of the key themes and recommendations are set out briefly in the following pages.

Theme 1: Migrating from a cost-centric paradigm to a value-centric paradigm based on public benefit: cost analysis

Technology and project evaluations are mainly based on techno-economic considerations. But can techno-economic considerations without an accompanying subjective assessment of impacts and implications really guide us in selecting and prioritizing technologies and projects?

Techno-economic considerations neither capture climate, societal, or environmental impacts nor consider risks related to energy security. Techno-economic considerations are cost-centric in the sense that they consider the cost of electricity as the key decision criterion.

Although there is no denying the criticality and the importance of the 'delivered cost of electricity' for India, a relook perhaps at what constitutes the estimation of this delivered cost is very much in order. For public policy making, costs should ideally represent the value of public benefits minus losses, where the public pays only for the surplus benefits.

It also has to be realized that in value terms, a 'low-cost' technology option may not be the most valuable. Land diverted from agriculture and forests and transformed into wasteland permanently by coal mining represents a loss to society and the environment. Direct and indirect impacts of pollutants like SOx NOx, SPM, heavy metals (lead, mercury, etc.), and radioactive particles also represent public losses.

Although these impacts are known and acknowledged, they are not considered because they cannot be measured. In the absence of a rigorous methodology to monetize public benefits and losses, the only way to 'value' choices is to weigh all the identified public benefits and losses, including costs.

In this context, the current exercise offers important insights that can be drawn from the current exercise which weighs all the identified public benefits and losses to derive 'value-based' priorities. Interestingly, the weighting-based exercise also suggests that when a universal consideration set is presented, the 'costs of electricity' or 'economics' are considered on par with other qualitative considerations and the importance of 'costs' becomes relative rather than absolute. This insight has to be acknowledged and incorporated in the current planning psyche.

Recommendations

Project evaluation based on techno-economics discounts project impacts, and other qualitative considerations that may be critical from a long-term policy perspective. Ideally, these qualitative measures have to be a part of project evaluation but cognitive limitations prevent us from making objective decisions from subjective comparisons. One practical way to widen the project evaluation framework is to assign costs to key qualitative measures. For a regulated electricity sector, such a framework has to be based on a public benefit: cost analysis, which could tell us whether the sum total of public benefits exceeds the sum total of public costs—the only public justification for any project or technology.

Under the current policy and regulatory regime, any category of costs or time periods other than those already stipulated cannot be considered. The format for EIAs submitted to the MoEF does not include any computation related to environmental costs, any methodology for assessing them, or any specification of the time period over which such valuation or the public or social discount rate is to be extended. For diversion of forest lands, the NPV of forest land (by the procedure mandated by the Supreme Court) does not contain any component relating to the future loss of biodiversity or of environmental functions performed by forests, nor does it compute the economic or livelihood losses to the surrounding communities that depend on that forest land. In effect, only the forest department is compensated for monetarily. Further, no methodology or procedure is in place for allocating any climate-related costs for any specific project or technology, no specific national determination of the social cost of carbon, and no specification of the time period to be considered; in effect, climate costs are denied, although it is clear that climate is a global externality.

Other key considerations are the effective discount rates that should be used and the time scales for impact evaluation. Ideally, a zero discount rate should be used for long-term cost-benefit calculations to realistically reflect future damage costs instead of making them conveniently disappear by applying a high discount rate, which is nothing more than business as usual. Further, it needs to be realized that environment and climate impacts may extend far beyond a project's lifetime, and even life-cycle assessments of a project may not give a reliable measure of the damage potential.

As a way forward, the first step could be to create a more inclusive public-benefit-to-cost framework based on inputs received from regulatory commissions, EIAs, future SIAs, computations of social cost of carbon as applicable to India, costing of forest lands and loss of forest-based livelihoods, future biodiversity losses, public subsidy costs, and macroeconomic costs related to mounting deficits and foreign exchange imbalances.

Such a framework would, in effect, also help resolve social and environmental issues related to project implementation by allowing diverse stakeholders to speak the same language. This would allow for a more transparent order of priorities both in terms of preferred technologies and in terms of projects and foster a healthy debate on societal role and environmental limits.

In this context, the weighting-based framework developed in the study could perhaps be a starting point for a more comprehensive technology and project assessment framework. The weighting-based framework can also serve to highlight the reasons behind conflicting stands against technologies and projects. With the weighting-based framework, the policymaker can view technology assessment or project assessment from different perspectives. For example, by giving higher weightings to social and economic parameters, one can assess technology priorities from a socio-economic perspective. This flexibility makes it possible to appreciate different point of views and to make the linkages and the co-dependencies of decision-making more transparent.

Theme 2: Review of project appraisal and management strategies

Large numbers of projects are stranded because of myriad reasons ranging from R&R issues to contractual delays, geological surprises, environmental clearance, shortage of capital equipment, technology challenges, etc. The optimum solution for supporting these projects is to take another look at current project management practices and overahaul, if necessary, the activities starting from project identification to final commissioning.

In case of hydro projects, a common refrain is the lack of proper due diligence in impact identification and mitigation strategies. Interestingly, some of the stakeholders who were consulted opined that opposition to large hydro stemmed more from the way hydro projects were developed than from the impacts of the projects. A literature review on this topic pointed to inherent problems with the project development process; for example, institutional commitment to develop hydro projects is made before a detailed environmental or social impact assessment. This often results in EIAs and SIAs that merely support project feasibility without really assessing the wider impacts and impact costs. In many cases, R&R packages have been designed arbitrarily and exclude some affected populations; the compensation too has been inadequate and unacceptable, especially for the deprived population.

Another issue with project development relates to the standard norms for environmental approvals, mainly the related environmental flows (e-flows) and project location. Proponents of the environment believe that the present stipulation of minimum e-flows cannot sustain a vibrant river ecosystem in the lean season. Further, the norm for the minimum distance between cascade projects and distance between projects and nearby biodiversity zones, forests, etc. also need to be reconsidered.

In addition to this, contractual delays and cost overruns have been a norm rather than an exception. Although delays and cost overruns in many cases are due to geological surprises, issues related to access to the site, or natural calamities, in many other cases, they are due to lax contracting clauses and ineffective project management. The lengthy approval process becomes even longer if project structuring and estimated costs change, since any such changes require a fresh set of approvals.

Similar issues dog all power projects, including coal-based projects, which are stranded on account of contractual issues, shortage of capital equipment, technological challenges, environmental clearances, even R&R issues, etc.

All these issues can be resolved only by considering each project individually so that each project is planned and managed with best-in-class project management practices.

Recommendations

A long-term strategy to manage projects is to understand best practices in project planning and management. For example, in the case of hydro projects, the methodology developed by the World Commission on Dams *(WCD (Nov 2000), Dams and Development: a new framework for decision making, The report of the World Commission on Dams)*, suitably modified to meet specific needs, could be a very good starting point. The key emphasis of the methodology is on more comprehensive and transparent social and environmental impact assessment and management plans. The methodology identifies 'negotiated prior consent' from affected population as a key strategy to manage R&R issues. Such a methodology can be suitably modified and integrated with the recommendations of the consortium of 7 IITs in the report 'Ganga river basin management plan: Sept.

2013'. One of the keys to adopting best practices is to conduct neutral and impartial EIA and SIA for projects from certifying agencies or special institutions that are regarded as neutral. These institutions can be compensated through an autonomous trust fund, which can be set up by the government and private developers. The same trust fund could also be empowered to take bank guarantees from the project developer to complete pre- and post-commissioning social and ecological restoration activities. Another strategy to ensure increased social and environmental due diligence could be to include environmental and social sustainability parameters in the lending guidelines of commercial lenders. Although many international banks and multilaterals have guidelines that mandate compliance with social and environmental sustainability norms before disbursement, such guidelines are more an exception than a norm. Inclusion of such norms in regulatory standards for commercial banks (Basel standards) could go a long way in ensuring better environmental and social due diligence.

Other issues relate to delays and cost overruns that not only represent stranded capacities but also are a double drain on the economy. In this regard, there is substantial scope for improvement in the tendering process, vendor identification, vendor qualification, contract negotiations, contract management, project financial management, etc. It would be important to learn from the management strategies of many complex private-sector projects that were commissioned on schedule or even earlier and without significant cost overruns. In this context, the first change could be to move from a 'cost-based selection' to a 'cost-competence-quality-based selection' in line with the practices in the private sector. Similarly, contract design should consider provisions that equate delays with revenue loss and ensure recovery from the contractor for delays.

For the short to medium term, flexible project support mechanisms can be designed to overcome anticipated challenges in implementing new projects. One way of using flexible support mechanisms is to restructure such projects by assigning each project a virtual capital credit (assigned as high or low) across parameters like technology, costs, climate, environment, and society. For example, in case of projects stranded solely for environmental and social opposition, the virtual capital credit for society and environment can be considered low while the technology, costs, and climate credits can be considered high. Restructuring the project would, in this case, would mean a trade-off involving the transfer of capital credit from the high-credit parameters (technology, costs, and climate) to low-credit parameters (society and the environment).

In simple terms, a trade-off between technology credits and society and environment credits could involve measures like reduction in project capacity (designed head, flow, infrastructure) and technology changes (cross-flow turbines to match high flow variability, fish-friendly turbines, etc.). Similarly, trade-off between costs on one hand and society and the environment on the other could involve enhanced compensation, increased provisions for minimizing ecological damage, maximization of ecological restoration benefits, etc. Transfers from climate credits could mean additional monetary or fiscal benefits related to avoided carbon costs, which will have to be stipulated.

Irrespective of the actual mechanisms used, the key strategy under project support mechanism has to be flexibility in project structuring in terms of not only technology configurations but also project costs and compensation packages. This would require revising DPRs and resubmitting them for local and central acceptance. This would take time but would nevertheless be faster than the current system.

Theme 3: Dovetailing short-term technology choices with long-term policy concerns

Caution has to be exercised that short-term exigencies do not result in suboptimal technology choices that cannot meet the future requirements of the grid in terms of operational flexibility, reliability, low cost, response times as well as a range of environmental, social, and climate concerns.

For example, according to WISE estimates (WISE (2013), Future of coal electricity in India and sustainable alternatives, World Institute of Sustainable Energy), peaking of coal may happen as early as 2032. By then, the current fleet of new greenfield plants would not have completed even half of their service lifetime. Even if the coal peaking occurs later, as is believed, the idea that coal is a limited resource cannot be ignored. Growing resource nationalism among coal-exporting countries suggests a clear realization that fossil fuel sources are essentially limited, and that increased exports compromise national energy security in the long run. Recent measures adopted by some coal-exporting countries to curtail extraction and exports and to increase export prices can be seen as an indication of future constraints on coal markets.

With this background, it is imperative that long-term policy objectives be defined and reconciled with short-term choices. For example, if energy security and low-carbon electricity are to be key long-term policy objectives, domestic coal- or gas-based capacities will have to be given precedence over imported coal- or gas-based capacities and clean coal technologies (IGCC or UCG) over ultra supercritical in the short term

More important, a critical assessment of long-term policy objectives and concerns will also provide crucial inputs into near-term policy planning related to technology management (R&D, indigenization, technology transfer, etc.), resource planning (domestic resource development, long term resource-import contracts), etc.

All this would suggest developing a clear vision of future policy objectives and to dovetail it with short- and medium-term planning for resource, technology management, and limited deployment plans. Some of the key themes that need to be considered in long-term policy planning and short-term support strategies are described below.

Recommendations

The current process of planning for power sector capacity has to go beyond merely assessing capacity addition to identifying and prioritizing more desirable technologies from which that capacity is to be generated. The process has to recognize that high-priority technologies have special merit and should be given special preferences.

The ideal technologies (transition technologies) are not only more climate- and environment-friendly but are also significantly more valuable given their ability to provide flexible support (baseload as well as peak load support). Which is why they should be given special preferences and special privileges in the form of appropriate policies and regulatory provisions. More important, it should be ensured that these special technologies are provided with customized tools to overcome implementation challenges.

Specifically, technologies that are considered more desirable (or are estimated to have higher public benefits) should be given greater support to facilitate their timely deployment and added provisions should be made for project support mechanisms to optimize the benefits: losses ratio. Such support could include concessions (waiver on taxes and duties), project facilitation (increased provision for capitalization, enhanced R&R provisions, single-window clearance, easier procedures for transferring land and water rights), and financial or commercial sops (preferential tariffs, subsidies, demand assurance, etc.). For example, specialized support mechanisms for hydro technologies could involve provisions for enhanced R&R packages in addition to subsidy support and preferential tariff instead of a tariff arrived at through the cost-plus methodology. Although such an approach would seem to go against established practices, the scale and range of advantages (technological, commercial, energy security, climate and pollution) and service capabilities (flexible generation) that hydro offers over a 40-year lifetime are greater than those offered by any other technology.

With this background, if we chose to appreciate the future advantages of these technologies over the current technologies, the first step would be to make a clear declaration of technology preference and define capacity targets. Such a declaration will have to be followed up with a detailed technology policy that will stipulate special policy and regulatory provisions to support technology incubation, manufacturing, and deployment. These provisions, in turn, will have to be supported with a detailed technology management plan to facilitate technology licensing, resource access, indigenization, manufacturing augmentation, and cost management.

Theme 4: Policy recognition of the importance of generation flexibility in the future grid

Constraints on the availability of coal and gas have led to greater penetration of RE, which, being variable, has to be compensated for through balancing mechanisms on the supply and demand sides. The principal mechanism on the supply side is the design flexibility built into conventional generation sources. Although the current operational and commercial mechanisms do not envisage such a role for conventional technologies, such transformation of their role is perhaps the only solution in medium term, until more reliable forecasting of RE is possible and solutions to store the energy generated become viable.

The importance of such generation flexibility cannot be overemphasized; it would not only allow optimum resource use (that can switch between part load, low-fuel operations under high RE and full load operations under low RE) but also provide additional economic opportunities to conventional technologies. Understandably, the commercial and technical implications and the accompanying regulatory measures for such a strategy will have to be discussed and weighed.

A detailed assessment of coal-based generation technologies (Annexe 1) suggests that they can provide moderate to low generation flexibility with comparatively high part-load efficiencies, which could be valuable in supporting renewables. This realization suggests that just as there is a heat value for coal that is burnt, there is also a 'system value' for coal that is not burnt in operating plants; this unburnt or unused coal is actually a natural energy storage option. This would mean that backing down and saving on coal could effectively mean enhanced storage availability. However, this perspective is clearly lacking in operational planning since coal-based technologies are discouraged from serving as flexible sources, and generators that respond to dynamic balancing requirements of the system are not compensated or rewarded. This will need to change.

Recommendations

One way to support generation flexibility in operation is to consider some stipulated balancing capacity window of conventional power technologies as storage and treat it as a system storage option rather than as a firm dispatch source. Although such a stipulation would necessitate separate regulatory norms for storage, it can also effectively allow generation capacities to provide frequency support ancillary services (FSAS). In this context, development of ancillary markets or creation of new regulatory framework specifically for incentivizing balancing functions could go a long way in bolstering support to variable RE during the high-generation season.

However, any such regulatory provision will also have to factor in the costs associated with efficiency loss and cycling for intermittent part-load operation of conventional generation technologies. Policy-level support for facilitating flexible operation could involve a higher depreciation benefit, tax incentives, exemption from duty, enhanced compensation packages to operators, subsidy for upgrading system automation, etc.

Theme 5: Developing a comprehensive technology management policy

Power sector is particularly dependent on technology imports: almost all generation technologies depend on foreign OEMs. Past efforts at indigenization have not been encouraging. Lack of core technology research, R&D professionals, R&D funds, and infrastructure severely constrains effective technology research and indigenization. Technology patent protection laws in India have also hindered technology trade and transfer in some cases.

These aspects need to be addressed by developing a comprehensive technology management strategy that looks at diverse techno-commercial-legal aspects related to technology transfer, technology licensing, patent law protection, R&D funding priorities, manufacturing policy, commercial exposure, capacity building, O&M and spares support, performance guarantees and penalties, capacity development, etc.

> The management of technology is the linking of different disciplines to plan, develop, implement, monitor, and control technological capabilities to shape and accomplish the strategic objectives of an organization.
> *(The management of technology and innovation: a strategic approach, Margaret A White and Garry D Burton).*

This definition would suggest that technology management should encompass not only R&D and pilot project support but a whole lot of activities including system engineering, technology evaluation, technology indigenization, component availability and costs, production processes, operational procedure, technology transfer and patent laws, capacity building, general management, financial management, and policy management. Developing such a 360-degree view would require a large team of interdisciplinary experts specializing in managing technology products and processes.

Recommendations

One way to manage such interdisciplinary activity is to create an autonomous body comprising specialists with technology management experience, drawn from industry, academia, and research institutions. The body can be entrusted with the task of managing the preferred technology choices. Some of the specific functions that such a body can be expected to perform are listed below.

- Undertake independent reviews of technologies
- Search for bilateral R&D collaboration opportunities (for control components and technologies)
- Assess raw material requirements and suggest strategies for securing raw material supplies
- Identify technology customization requirements, discuss technology modifications, costs, and indigenization opportunities with technology OEMs on behalf of the Govt of India
- Identify training needs along the entire value chain from R&D to production, manufacturing, installation, commissioning, and operation and maintenance
- Facilitate technology transfer or technology import agreements
- Advise the Government of India on detailed technology adoption plan covering independent technology impact assessment, activity lists for adoption with priorities and responsibilities,

training and personnel needs, budgetary support requirement across the activities, and a time frame for implementation

Understandably, an organization with these duties will need highly skilled and technical professionals and these professionals would come at a cost. These costs will have to be met through parallel contribution from industry bodies, technology providers, OEMs, bilateral funding agencies, and the Government of India, all routed through it. An autonomous status is essential for this body to ensure that it works without any influence and is able to build up credibility as an independent think tank.

Theme 6: Transition technologies: a new perspective

Some technologies that have come to be seen as good transition choices and need to be considered for special policy focus.

1. **The criticality of fuel flexibility: circulating fluidized bed combustion technology (CFBC)**

   Fuel flexibility means the ability of a technology to accept fuels of different quality. For the technologies under consideration, fuel flexibility refers mainly to the ability of CFBC boilers to accept a wide range of fuels.

   One of the major differentiating features of circulating fluidized bed (CFB) boiler is its fuel flexibility in that it can burn a variety of fuels without major effect on performance whereas a PC boiler can only be operated for the fuel for which it is designed. CFBC boilers also provide significant environmental benefits because of their low NOx emissions and their suitability to capture SOx.

   But the real advantages in terms of fuel flexibility of CFBC are captured in the following excerpts from the technical literature of two original equipment manufacturers (OEMs).

   CFB technology brings the capability of designs for a wide range of fuels from low quality to high quality fuels, lower emissions, elimination of high maintenance pulverizers, low auxiliary fuel support and reduced life cycle costs. CFB can be the technology of choice for several reasons. The CFB can handle a wide range of fuels such as coal, waste coal, anthracite, lignite, petroleum coke and agricultural waste, with low heating value (>1500 kcal/kg), high moisture content (< 55%), and high ash content (< 60%). The fuel flexibility provides use of opportunity fuels where uncertainty of fuel supply exists and economics are an issue. If a CFB boiler is designed for coal, the same boiler can be used to burn lignite or petroleum coke or anthracite. The material handling and feeding system should be properly designed to meet these fuel variations. Such fuel flexibility is not available in the competing conventional PC-fired boiler technologies. This is one of the important features of CFB that the customer needs to analyze carefully before selecting a technology.

   —*Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power* by S Kavidass, G L Anderson, and G S NortonJ. The Babcock & Wilcox Company, 20–22 September 2000.)

   The fuel procurement flexibility for CFB steam generators provides long term fuel security and full access to the arbitrage in the global fuel market. The combustion temperature in a CFB is about 850 °C vs. 1500 °C for a PC boiler. In a PC boiler, melting ash can cause slagging and corrosion in the furnace and soot blowing is required. Slagging and corrosion are minimized in a CFB furnace and soot blowing, if required at all, is only necessary in the heat recovery area of the unit.

—*The CFB Technology Benefits in Comparison with Conventional Solid Fuel Generation Technologies for Utility and Cogeneration Applications* by Kalle Nuortimo, Harry Lampenius, Anna Khryashcheva, and Tobias Boensel. Foster Wheeler Energia, March 2013

Although flexible fuel operation does have an impact on the CFBC boiler efficiency, an empirical study based on simulation on a 40 TPH boiler *(*suggests that the impact is marginal and is much smaller compared to that on a PC-based boiler, in which changes in fuel mix can reduce efficiency significantly or can even result in breakdowns. *(Ref: Vijay K. Patel (2013). Efficiency with different GCV of coal and efficiency improvement opportunity in boiler. International Journal of Innovative Research in Science, Engineering and Technology, Vol. 2, Issue 5, May 2013, ISSN: 2319-8753, pp 1518-1527)*

Literature suggests specific benefits that may have implications for long-term energy security by allowing CFBC-based plants to vary their fuel feedstock depending on fuel costs and markets. This advantage needs to be recognized and considered in technology selection.

Recommendations

The ability to handle a range of fuels of varying quality makes CFBC units an attractive technology option. CFBC boilers are capable of handling low-grade as well as high-grade coals and even lignite. Lower NOx and SOx emissions are other advantages of CFBC boilers. However, CFBC boilers for supercritical size are still new (only one CFBC supercritical plant is in operation worldwide) and only a few foreign OEMs have the capacity to develop large-scale CFBC units. However, the strategic advantages of this technology related to energy security should outweigh technology access considerations and spur early adoption of this technology in India.

The first step to support this technology is to declare CFBC as a preferred technology option and plan an early pilot trial. In parallel, a comprehensive technology management plan should be developed that integrates diverse aspects related to R&D, system engineering, technology evaluation, technology indigenization, component availability and costs, technology transfer and patent laws to ensure early commercialization of the technology.

2. Pumped hydro storage as system asset

Pumped hydro emerges as a very good transition technology from the technology assessment framework. Technically, it can provide excellent load-following capability, large storage capacity, and ideal grid-management services. One major reason for the limited use of pumped storage in India is the deficit of surplus power for pumping. However, if the planned capacity of RE sources is achieved in future, the surplus power for pumping can be drawn from RE sources, increasing the overall system utilization. However, major issues with pumped hydro seem to be related to commercial feasibility considering the high capital costs and net energy loss. A built capacity will have to recover its investment costs in addition to its operating costs (normal O&M costs as well as the pumping costs), and the final delivered cost of energy may be high. Another issue is the location specificity of pumped hydro schemes.

However, despite these issues, pumped hydro storage can yet make sense for utilities as well as renewable energy suppliers if it is considered a system asset rather than a commercial asset. Using pumped hydro as a balancing asset when solar power is abundant is technically feasible and may also become commercially viable under certain conditions. Pumped hydro systems can also provide ideal frequency support ancillary services and work as the first-level response before conventional generation technologies.

Recommendations

One of the most effective ways to develop pumped storage capacity cost-effectively is to replace, wherever possible, one or more turbines units of existing 'capacity-limited' hydro projects with reversible pump turbines that can run in both turbine and pump modes. This would, at once, reduce costs and also allow utilities to save on costly peak-time purchases and earn additional revenue through the market route. Using the existing medium-size irrigation dams for establishing greenfield pumped hydro projects could also make sense considering the huge intra-day cost differential between peak and non-peak power. Recent experiments with pumped hydro also point out ways in which large pumped storage capacities can be built with underground storage using a piston in a cylindrically excavated tunnel along with a penstock and a pump turbine unit (www.gravitypower.net). All this suggests great scope for pumped hydro as a technically and commercially viable technology for India.

From a regulatory perspective, pumped hydro power can also provide the first level of frequency support ancillary services (FSAS) in the proposed ancillary services market. Another possibility to make pumped hydro feasible could be to pair, partly or fully, pumped hydro capacity of a particular project with a renewable generation management centre, which, in turn, would be allowed to use the allocated storage capacity to maximize its revenue potential by selling the hydro generation in open market. In turn, the utility could get either a share of the trade surplus or a waiver based on negotiated generation set off. This would be a particularly beneficial arrangement for 'out of operation' or dilapidated pumped hydro units that can be infused with funds from the RE management unit or a third party, which is then allowed to use the operational storage for its own gains.

Pumped hydro has the potential to provide excellent power system services at low environment, climate, and social costs and, if made to work in conjunction with renewables, can prove commercially successful.

3. Feasible coal alternative: underground coal gasification

Underground coal gasification is emerging as the best coal-based transition technology. Initial estimates predict good prospects for UCG in India because it offers significant advantages over other coal-based technologies across climate, environmental (air pollution, biodiversity), and social aspects (land use) in addition to its reduced energy security risks. Availability of suitable sites and technology access can make UCG a preferred choice even in economic and performance terms. Additionally, UCG can work best with high-ash Indian coal and can utilize the coal available in seams that are not considered feasible for commercial extraction. Although international experience with pilot projects suggests risks of water contamination and land subsidence, the other benefits could outweigh these considerations especially if sites are selected judiciously.

Recommendations

An immediate policy priority is to identify possible sites, estimate their resources, and follow up with detailed geological and geotechnical investigations to limit proximity to water bodies (to eliminate water pollution) and to assess the strength of the underlying rock strata (to rule out land subsidence). Considering the nascency of this technology in India, appropriate technology assessment will have to be carried out and technology partnerships forged for resource assessment and site selection. Efforts on R&D and investments in pilot projects should ideally begin only after a thorough assessment of resources and sites.

4. **Building up flexibility through R&M of old subcritical plants** Fundamentally, the response of coal-based units (thermal units with solid fuels) to load changes is lower than that of other technologies like gas turbines because of the inertia associated with pulverization and consequent combustion. Subcritical technology distinguishes itself from others by using a steam drum in the boiler section. The enormous thermal mass in a boiler responds to load changes based on fuel feed rates over minutes. Although, subcritical units can respond faster (a 5%–15% over a few seconds) by using the energy storage capacity in the steam drum, this can be achieved only for a limited time by keeping the overload throttled turbine valves partly closed, which makes it possible to re-open them quickly when required (Ref. IEA (June 2012) Operating flexibility of power plants with CCS, IEA GHG R&D, Section 3.1). In the constant-pressure mode of normal operation in subcritical units, the throttle valve controls the steam output, which is mainly limited by temperature gradients accepted by the HP turbine. This process is inefficient and leads to pressure loss at various stages in the cycle.

   However, old coal-based subcritical plants can be retrofitted or replaced with specific system components and controllers to perform cycling operations and sustain them over longer periods while incurring only limited damage.

   Recommendations
   Variable pressure operation is a better option as it keeps the throttle valve open and varies steam temperature according to the load requirements by controlling the fuel feed rates. This will keep the temperature gradients in the HP at an acceptable level even during cycling operation. This control scheme helps improve the response time of the unit at the cost of only marginal loss in efficiency. Another control option to increase flexibility is to adjust feed water extraction at HP and LP turbine stages. This preheats the water entering the steam cycle, thereby increasing the cyclic efficiency, and thus requires less fuel to cope with changes in load. This option is called HP heater bypass preheater and condensate throttling.

   Turbine, feed water extraction, and fuel adjustments can all be controlled automatically. This mechanism helps to control, monitor, and operate a plant allowing dynamic control of operating conditions. Another retrofit recommended is tilting burners. The position of the fireball should be lower in the evaporative section so as to increase steam production. This will affect the re-heater section as the fireball is moved from its positioning, lowering the plant's efficiency. This increases the load-following performance of a unit without changing firing rates.

   Pulverizer is considered the biggest hindrance during the cycling operation because it has the slowest response time in the cycle. Increasing the grinding pressure during ramping up will deliver coal faster to the furnace, thereby increasing power output. Variable-speed motors can increase or decrease the grinder pressure based on load requirement and reduce the loss in efficiency due to cycling (Ref. Ken Dragoon and Jimmy Lindsay (Aug 2010), Summary report on coal plant dynamic performance capability, Renewable Northwest Project, pp. 3, 4, 6).

In addition to the overarching themes, some of the key observations and recommendations on other conventional generation technologies covered in the study relate to their technical feasibility and technology support needs.

1. **Supercritical PC technology** is already mature worldwide with a few units already operational in India. The need for increased efficiency, larger units, sizes and lower coal consumption makes the technology attractive in India. The 13th Five-Year Plan recommends new coal-based units to be of

supercritical technology. Most of the supercritical units currently operating in India are designed for high-GCV imported coal or blended coal. The performance of supercritical units currently operating on low-GCV, high-ash domestic coal should be critically evaluated and any performance-related issues resolved because the technology has implications for long-term dependence. Considering the status of the technology, the focus could be on assessing design customization needs and indigenization opportunities.

2. **Ultra supercritical PC technology** has not been modelled yet for low-GCV domestic coal. The high operating temperature demands use of austenitic steels, which also make the technology costly. There is hardly any domestic manufacturing of austenitic steel components. The key factors that need to be considered before adopting this technology relate to boiler customization (for running on domestic coal), technology and metallurgy costs, and operational reliability and issues (mainly related to failures or breakdown due to failure of complex metallurgical interfaces). It would be advisable to review these considerations over five years before recommending any policy preferences.

3. **Integrated gasification and combined cycle technology** is yet to be considered a mature and reliable technology for power generation. Although the entrained flow gasifier technology for IGCC is mature and available, it is expected that it may not be suitable for low-grade Indian coal. On the other hand, IGCC with fluidized bed gasifier technology can handle wider variations in fuel quality but is not available as large unit sizes.

   The best strategy for IGCC could be to support R&D on developing large-capacity fluidized bed gasifiers. The mature technology based on entrained-flow gasifiers may have to be reviewed for operational reliability, mainly for use with Indian coal, before being adopted for large-scale implementation. The costs of IGCC will also have to be closely monitored to assess its feasibility.

4. **Gas-based power plants either open cycle and closed cycle** have apparently no specific recommendations related to technology. However, from a planning perspective, it is established that resource constraints more than anything else will dictate whether the technology is adopted.

5. **Hydropower** is the most mature technology as far as India is concerned. Although India has a wide base of manufacturers of equipment for hydro power projects, many other issues like delay in clearances, geological surprises, natural calamities, R&R, investment decisions, contracts, and delay in signing of MoUs make the technology a risky proposition.

   These problems, more in storage-based plants, need to be addressed by rigorous technology design and strong contractual procedures. Unlike other conventional technologies, each hydro project is a special case representing a unique mix of diverse factors that pose unique challenges. In this context, it is very difficult to offer generalized guidelines. However, using a public cost: benefit analysis framework (see Theme 1) or working out a flexible, project-specific policy and regulatory package would perhaps help in solving some of the problems.

6. Advanced ultra supercritical

Advanced ultra supercritical, or A-USC, plants are those that operate at higher pressures and temperatures of steam: 300 bar (30 MPa) and 700 °C or above. The current fleet of supercritical or USC plants are typically only incrementally superior to the subcritical units (2–4 percentage points) whereas higher pressures and temperatures (300–350 bar and 700–750 °C) can be far more efficient—45–47 percentage points on gross basis, or 10%–12% more efficient than even the supercritical units currently in service. Besides, A-USC plants are expected to bring down CO_2 emission to ~ 700 g/kWh.

Materials are the major constraints to the deployment of this technology. Beyond 650 °C, corrosion increases significantly up to 690 °C and then falls. Steam-side oxidation rates and weight loss are lower for materials with chromium content of more than 12% with ferritic steels and more than 19% for iron-based austenitic materials. Research is in progress, and a pilot plant is scheduled to be operational in 2018 (refer Annexe 1).

Since fuel has a major influence on the design and the cost of a boiler, attempts are on to model the boiler for Indian coal. Several studies list multiple challenges with Indian coal like very high ash (ash loading per megawatt 7–10 times that with typical imported coal) and the presence of alpha quartz, which can lead to severe erosion. These challenges call for substantial reduction in the velocity of flue gas across the boiler and, consequently, significantly larger boilers as well as larger pulverizes and other auxiliaries. However, by far the single greatest challenge for deployment in India will be metallurgical advancement. It would be advisable to wait and watch the performance of the first pilot plant before forming any opinion on the suitability of the technology.

7. Carbon capture and storage

There has been a slowdown in CCS projects worldwide: several projects have been cancelled, put on hold, or scaled down, primarily on investment and financial considerations. India has been exploring the feasibility of CCS through small projects, mainly on laboratory scale. The barriers in India, apart from economic considerations, are lack of storage sites in the hinterland. The only feasible locations are in north-east and they are far away from generation centres, which means the costs of transport and transport infrastructure are likely to be very high. Technically, this could be the biggest challenge for India. In commercial terms, CCS could be viable if the avoided cost of carbon is also taken into account. However, the most important consideration is the lack of even a single operational project. It would be advisable to clearly understand the technological challenges first by analysing operational data before any effort is made to assess the feasibility of deploying CCS in India.

8. Combined heat and power

Cogeneration and trigeneration are the basic modes of combined heat and power (CHP). Cogeneration efficiency is directly related to the heat-to-power ratio.

Cogen efficiency varies with proportion of heat (steam) to power for a given project. If the demands for power and steam are relatively low (say less than 500 MWh and less than 10 000 TPA, or tonnes per annum), economic optimization suggests boilers fitted with a backpressure turbo-generator. The steam from the exhaust of the turbine is used in the process along with the electricity generated from the turbo-generator. However, since the variation in steam may not be synchronous with the variation in the demand for power, the system would not always be trouble free. Unless the heat-to-power ratio is beyond a certain threshold, cogen may not be economically viable for small-scale applications.

The application of CHP in India is limited to process industries and large-scale requirements for air cooling (hospitals, hotels, and malls). The heat and steam requirements are not always compatible with operating conditions of generating units. This issue needs to be addressed before making any plans to deploy utility-scale CHP in India.

9. Renovation and modernization

Subcritical thermal generation units in India that have been in operation for 25 years can be retrofitted for operating as flexible plants. This has been discussed separately. However, life extension projects for subcritical units need a rethink, particularly because subcritical technology is near obsolescence. An alternative could be to replace subcritical plants with supercritical plants after upgrading the infrastructure as required.

Civil constructions of hydro units have a lifespan of 100 years but the mechanical and electrical equipment needs renovation every 25–30 years. Modern turbines deliver much higher output than that delivered by turbines that were manufactured several decades ago.

The basis for R&M is optimum utilization of available resources as compared to investing in greenfield projects. With the depleting natural resources, R&M may take centre stage in a few years but requires streamlined laws and policies for its promotion. However, R&M has to be preceded by a thorough cost-benefit analysis, and decisions should only be made case by case.

Summary

The identified themes have been discussed specifically to present a different perspective to policymakers and energy-sector planners and professionals. Although many of the insights may seem intuitive, many others would be informative: in either case, the simple expectation from policymakers and stakeholders in the energy sector is that they take note of these insights and recommendations, evaluate them, and form objective opinions.

The recurring theme of the current project, as described in the preceding narrative, is facilitating a paradigm shift in identifying and adopting sustainable technology choices for the future. We hope and believe that this study will facilitate informed decision-making that will achieve that paradigm shift.

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CHAPTER 8

CONCLUSION

8

CONCLUSION

The study has come up with some particularly critical findings related to technology choices and technology evaluation. More important, the study has also generated interesting insights that have implications for power sector policy, system planning and operations, and electricity regulation.

On the technology front, the study findings accord the highest preference to hydro, followed by gas- and coal-based technologies. This order of priority is consistent across both the orders of priority, namely those that take generation flexibility into account and those that do not.

Although a higher preference for hydro may seem counterintuitive considering the 'significant' social and environmental impacts of hydro, the study shows that other conventional alternatives to hydro fare even worse if we consider the life cycle impacts of these technologies, starting from resource extraction to resource use and handling. The fact that hydro technologies have moderate costs, limited climate and public health impacts, and significantly lower energy security risks clearly makes a case for favouring hydro over other technologies.

However, it should be noted that this preference for hydro should not be seen as a carte blanche to all hydro projects. The first prerequisite to a successful hydro programme is the executive commitment to genuinely addressing the social and environmental impacts of hydro and not dismissing them as collateral damage. The second prerequisite is comprehensive and impartial environmental impact assessment (EIA) and social impact assessment (SIA), followed by negotiated strategies to address the identified impacts and setting aside adequate funds to implement those strategies before making an institutional commitment to the project.

Among hydro technologies, the study recommends run-of-the-river (RoR) with pondage-based hydro to storage hydro and pumped storage hydro. Although storage-based hydro is technologically superior, RoR with pondage is more benign and could play an important role as a balancing reserve. Pumped storage hydro, which also emerges as a good transition choice, could serve better as a system asset than as a commercial asset.

Gas-based technologies emerge as the next best transition technologies but can be ruled out in the short term given the constraints on the availability of gas. However, gas-based technologies are a better choice than coal-based technologies and should be preferred if the availability of gas ceases to be a serious constraint.

Among coal-based technologies, underground coal gasification emerges as the best technology. The significant advantages UCG offers over other coal-based technologies in terms of climate, environment, society and energy security suggest a more in-depth examination of the feasibility of this promising technology on the ground. Supercritical technology, which is relatively new to India, seems an ideal candidate for baseload planning. However, considering the possible variations in future coal resources and blending requirements, a parallel policy preference to CFBC supercritical technology may help in early acceptance and adoption of the technology. Ultra supercritical technology still needs a detailed look to assess its suitability to Indian coal and its operational reliability (considering the complex metallurgy). IGCC, which is considered to be a superior alternative to conventional coal-based technologies in terms of environmental performance, remains dogged by reliability issues and high costs, and these problems need to be solved before IGCC can be a candidate in system planning.

To summarize, the derived transition technology priorities put hydro at the top, followed by gas-based and coal-based technologies. Integrating these transition technology priorities into the current and future planning would require us to address the formidable challenges facing implementation of these technologies: R&R issues, environmental opposition, contracting delays, etc., for hydro; gas availability for gas-based technologies; and contracting and R&R issues for coal-based technologies. To address these challenges, both systems and mindsets need to change. For example, in the case of hydro, although negotiated compensation packages and a detailed environmental restoration plan would increase the project cost, both would also significantly enhance the social and environmental 'value' of the project, generate goodwill, and reduce resistance. The justification for such a project should then be that it provides electricity not so much at lower cost as at higher value.

These and other insights from the study clearly suggest adoption of a 'value'-based approach rather than a 'cost'-based approach to evaluate transition technologies, which have significant 'system' advantage in terms of sustainability parameters and their ability to provide baseload and peak load support in addition to providing discrete or dedicated support to renewables. A business-as-usual approach to planning and technology evaluation will be unsustainable in the long run as it will lead us to the same problems that we face now. However, switching to a value-based system requires nothing less than an overhaul of our established systems of evaluation and planning—a complete paradigm shift.

We hope and believe that this study will facilitate such a transition to a more inclusive paradigm.

ANNEXE 1

TECHNOLOGY ASSESSMENT OF COMBUSTION TECHNOLOGIES FOR POWER GENERATION

Annexe 1

TECHNOLOGY ASSESSMENT OF COMBUSTION TECHNOLOGIES FOR POWER GENERATION

By

A K SASINDRAN

SYNOPSIS

This report has been prepared based on the primary Terms of Reference (ToR) provided by World Institute of Sustainable Energy (WISE), Pune.

The report attempts to capture the thermal power generation technologies available across the globe at various stages of maturity, along with ongoing developments, as well as challenges faced in each of the technologies, and co-relate the same for the Indian power generation sector for the medium term.

While a large part of the report and findings owes its source to the literature available in the public domain, the author has taken adequate care to apply his best professional judgment about the veracity of various statements, facts and figures published in those documents.

The author expresses his sincere gratitude to Prof. Sanjeev Ghotge, Joint Director, WISE, and his team for extending necessary assistance, including sharing valuable data base available with them, towards fulfilling this assignment.

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Glossary

A-USC	Advanced ultra -supercritical
AFT	Ash Fusion Temperature
AGR	Acid gas removal
APC	Auxiliary Power Consumption
APDRP	Accelerated Power Development & Reform Programme
APH	Air Pre Heater
APM	Administered Price Mechanism
AT&C	Aggregate Technical & Commercial
ASU	Air Separation Unit
BACT	Best available control technology
B & W	Babcox & Wilcox
BCM	billion cubic meters
BEE	Bureau of Energy Efficiency
BFBC	Bubbling fluidized bed combustion
BFP	Boiler Feed Pump
BFW	Boiler feed water
BFP	Boiler feed pump
Btu	British thermal unit
BU	Billion units or Billion Kwh
CAD	Current Account Deficit
CAG	Comptroller & Auditor General
Capex	Capital Expenditure
CBM	Coal Bed Methane
C&I	Control & Instrumentation
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage.
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CF	Capacity factor
CFB	Circulating fluidized bed
CFBC	Circulating fluidized bed Combustion
CGE	Cold gas efficiency
CHP	Combined Heat & Power
CIL	Coal India Ltd.
cm	Centimetre
CO	Carbon Monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
C_OP	Conoco Phillips
COS	Carbonyl sulphide
CPP	Captive Power Plant
CPRI	Central Power Research Institute
CRT	Cathode ray tube

kJ/kWh	Kilojoules per kilowatt hour
kJ/Nm^3	Kilojoules per normal cubic meter
km	kilometre
kW	Kilowatt
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/hr	Pounds per hour
LCOE	Levelized cost of electricity
LEP	Life Extension Programme
LF	Load Factor
LHV	Lower heating value
LNB	Low NOx Burner
LNG	Liquefied Natural Gas
LP	Lower pressure
LPT	Low Pressure Turbine
LSB	Last Stage Blade
lpm	Litre per minute
m	Meter
m^3/min	Cubic meter per minute
Mcum	million cubic meters
MCL	Mahanadi Coalfield Limited
MMBtu	Million British thermal units
MMBtu	Million British thermal units
MNRE	Ministry of New & Renewable Energy
MoC	Ministry of coal
MoEF	Ministry of Environment & Forest
MoP	Ministry of Power
MOU	Memorandum Of Understanding
MPa	Megapascals
MT	Million Tonne
MToe	Million Tonnes Oil equivalent
MTPA	Million Tonnes per Annum
MU	Million Units
MVA	Mega volt-amps
MWe	Megawatts-electric
MWh	Megawatts-hour
MWth	Megawatts thermal
NA	Not applicable
NCL	Northern Coal Fields Limited
NDT	Non Destructive Test
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NLC	Neyveli Lignite Corporation
Nm^3/hr	Normal cubic meter per hour

CS	Carbon Steel
CSP	Concentrated Solar Power
CT	Combustion Turbine
CTU	Central Transmission Utilities
CV	Calorific Value
CWP	Circulating water pump
CWS	Circulating Water System
DAE	Department of Atomic energy
DCS	Distributed control system
D/E	Debt: Equity
DG Set	Diesel Generating Set
DISCOM	
DMW	Demineralised Water/ Dissimilar Metal Welds
DOE	Department of energy
DPR	Detailed Project Report
DSM	Demand Side Management
DST	Depth of Science & Technology
EC	European Commission
ECL	Eastern Coal Fields Limited
EE	Efficiency Enhancement
EHV	Extra High Voltage
EIA	Energy Information Administration
EOR	Enhance Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EPS	Electric Power Survey
ERC	Electricity Regulatory Commission
ESCO	Energy Service Company
ESP	Electro Static Precipitator
FBC	Fluidised Bed Combustion
FBG	Fluidized bed gasifier
FC	Fixed Carbon
FGD	Flue gas desulfurization
FEED	Front-End Engineering Design
FO	Forced Outage
FOAK	First-of-a-kind
FT	Fluid Temperature
FY	Financial Year
FW	Feed water
ft	Foot, feet
GAIL	Gas Authority Of India Limited
GCV	Gross Calorific Value
GDP	Gross domestic product
GHG	Greenhouse gas
GJ	Gigajoules
NOAK	N^{th} -of-a-kind
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NTP	National Tariff Policy
NTPC	National Thermal Power Corporation
N_2	Nitrogen
Opex	Operating Expenditure
O&M	Operation and maintenance
OCGT	Open Cycle Gas Turbine
O_2	Oxygen
OEM	Original Equipment Manufacturer
PAH	Poly Aromatic Hydrocarbon
PC	Pulverized Coal Combustion
PF	Pulverised Fuel
PFBC	Pressurised Fluidized Bed Combustion
PGCIL	Power Grid Corporation of India Ltd.
ph	Phase
PLF	Plant Load Factor
PM	Particulate matter
PPA	Power Purchase Agreement
PPM	Parts per million
PSA	Principal Scientific Adviser
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
RE	Renewable Energy
RET	Renewable Energy Technology
RETs	Renewable Energy Technologies
R&D	Research and Development
RDS	Research, Development and demonstration
RH	Reheater
RIL	Reliance Industries Limited
RM	Reserve Margin
R&M	Renovation & Modernisation
ROE	Return on Equity
SCCL	Singareni Collieries Company Limited
S/C	Single Circuit
SC	Supercritical (steam conditions)
SCR	Selective Catalytic Reduction
scf	Standard cubic feet
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
SCGP	Shell Coal Gasification Process
SEB	State Electricity Board
SECL	South Eastern Coal Fields Limited

GJ/hr	Gigajoules per hour	SERC	State Electricity Regulatory Commission
GOI	Government Of India	SFC	Specific Fuel Oil Consumption
GPS	Geographic Positioning System	SFG	Siemens Fuel Gasifier
gpm	Gallons per minute	SGC	Synthesis gas cooler
GSPC	Gujarat State Petroleum Corporation	SGS	Sour gas shift
GT	Gas Turbine	SH	Super Heater
GW	Giga Watt	SNCR	Selective non-catalytic reduction
HELE	High-efficiency, low-emissions	SNG	Synthetic natural gas
HFO	Heavy Petroleum Stock	SOx	Oxides of Sulphur
HGI	Hard groove Grindability Index	SO_2	Sulphur dioxide
HHV	Higher heating value	SPM	Suspended Particulate Matter
hr	Hour	SRU	Sulphur recovery unit
Hg	Mercury	SS	Stainless steel
H_2	Hydrogen	STG	Steam turbine generator
H_2O	Water	Syngas	Synthesis gas
HDPE	High Density Polyethylene	T&D	Transmission & Distribution
HHV	Higher heating value	TASC	Total as-spent cost
hp	Horsepower	TCF	Terra cubic Feet
HP	High Pressure	TERI	The Energy Research Institute
HPT	High pressure turbine	TOC	Total overnight
HR	Heat Rate	TOD	Time Of Day
HRSG	Heat-recovery steam generator	TOU	Time Of Use
HSD	High Speed Diesel	TPA	Tonnes Per Annum
HT	High Tension	TPC	Total plant cost
HT	Hemispherical Temperature	tpd	Tons per day
HVAC	Heating, Ventilating, and air conditioning	TPH	Tons per hour
HVDC	High Voltage Distribution System	TRIG™	Transport Reactor Integrated Gasification
HWT	Hot water temperature	TS&M	Transport, storage, and monitoring
Hz	Hertz	UCG	Underground Coal Gasification
ID	Induced Draft	UI	Unscheduled Interchange
IDT	Initial Deformation Temperature	UMPP	Ultra Mega Power Project
IEA	International Energy Agency	UN	United Nations
IEEE	Institute of Electrical and Electronics Engineers	UNEP	United Nation Environment Programme
IEGC	Indian Electricity Grid Code	USC	Ultra-supercritical (steam conditions)
IGCC	Integrated gasification Combined Cycle	US DOE	United States Department Of Energy
IGCAR	Indira Gandhi Centre for Atomic Research	US EPA	United States Environmental Protection Agency
IGFC	Integrated gasification fuel cell	VAM	Vapour Absorption Machine
IISC	Indian Institute of Science	VM	Volatile Matter
IIT	Indian Institute of Technology	VOC	Volatile Organic Compound
IP	Intermediate pressure	vol%	Volume percent
IPT	Intermediate pressure turbine	WB	Wet bulb
IPP	Independent Power Producer	WCL	Western Coalfields Limited
IPR	Intellectual Property Rights	WEC	World Energy Council
IS	Indian Standard	WGC	Water gas shift
ISO	International Standards Organization	wt%	Weight percent
IT	Information Technology	$/MMBtu	

KBR	Kellogg Brown and Root	$/MWh	dollars per megawatt hour
kCal	Kilo Calorie	C	Degree Celsius
kg/hr	Kilogram per hour	F	Degree Fahrenheit
kJ/kg	Kilojoules per kilogram		

EXECUTIVE SUMMARY

1.0 OVERVIEW

1.1 About 70% of utility power generation in India is through solid fuel – sub-bituminous coal and lignite and hence, as of now, it remains the backbone of the power generation sector.

1.2 Lignite based power plants are located in Tamil Nadu and Rajasthan; besides, a few are being developed in Rajasthan.

1.3 Unit size and station capacities: Till 2011, the largest unit capacity in India was 500 MW; however, a fast migration into 660 and 800 MW unit capacities is currently underway in the country across all power utilities. Further, the stations under construction are mostly with capacities exceeding 1000 MW with a number of stations exceeding 2000 MW.

1.4 A number of prime overseas OEMs in collaboration with Indian companies have established facilities for the local manufacturing of equipment.

2.0 INDIAN COAL / LIGNITE:

2.1 The major differentiating factor for Indian coal is the significantly high ash content with median values in the 40% range. This, coupled with relatively low heat content, raises the ash loading per unit energy input in Indian boilers 7 to 10 times the global average. In view of this, boilers and their critical auxiliaries designed for Indian domestically mined coal have a much larger size.

2.2 There are two major basins for lignite in India, one in Neyveli and the other in the Gujarat-Rajasthan region. Neyveli lignite is characterised by high moisture of up to 55% whereas lignite in Gujarat is characterised by medium to high sulphur

3.0 COAL /LIGNITE BASED GENERATION TECHNOLOGIES ALREADY MATURED IN INDIA.

3.1 Subcritical pulverised fuel fired technology has been the mainstay of India's utility thermal power generation and a number of units up to unit sizes of 500 MW have been operating across the country.

3.2 Recently, 600 MW size subcritical units have been introduced.

3.3 Supercritical units were only introduced in India in the recent past; however, in view of their overall advantage, the population of supercritical units has been found to be steadily increasing during the past years. The current sizes operating in India are 660 MW with Indian coal and 800 MW with imported coal. It is expected that in due course, supercritical units will become the mainstay of the Indian thermal power generation sector.

3.4 At present, supercritical steam cycle employed for Indian projects are limited to the mid-range (sub-600 °C). Ultra supercritical (USC) technology which uses steam temperatures above 600°C has not been found to be cost-economic for ruling Indian domestic coal prices.

3.5 There are a number of OEMs who can manufacture and supply supercritical thermal power equipment across the globe. In India a number of local companies have entered into joint ventures for manufacture of these units.

3.6 The start- up periods and grid-response characteristics of both subcritical and supercritical pulverised fuel fired units have been found to be moderate and in a close range.

3.7 Advanced Ultra supercritical (A-USC) units are those with steam pressure and temperatures higher than 300 bar and 700 °C. These are expected to give plant efficiencies in the range of 45-47 % in Indian conditions.

3.8 However, A-USC unit development is still in incipient stages and there have been setbacks in the development of certain super-alloys required for component development.

3.9 An A-USC unit requires a significant amount of nickel based super alloys. The average price of nickel during the past few years has been about 30 - 40 times the price of carbon steel.

3.10 Also, in India, development of components for A-USC units has been on-going with a trilateral collaboration between BHEL, IGCAR and NTPC. Though the initial plan for the demonstration was set at 2018, it may understandably get delayed further.

3.11 At the current projections, stand-alone A-USC units may cost more than double the cost of current supercritical fleet; However, A-USC units may cost about Rs 85 - 105 million per MW when built on a scale of 4 GW station size at multiple locations simultaneously.

3.12 The primary characteristics of Fluidized bed combustion (FBC) are inherently low generation of NOx and their ability to capture sulphur by sorbent injection. Further, FBC technology can accept a wide variety of fuels (including coal washery rejects) with stable behaviour, which is not possible with PC boilers.

3.13 Circulating fluidised bed combustion (CFBC) is the most mature FBC technology. It has been found that CFBC boilers can be a better economic choice for moderate levels of atmospheric emissions when compared to PC boilers since the latter requires fitting with expensive end-of-pipe FGD and De-NOxing systems for meeting the same levels of emission caps.

3.14 From a fuel characteristic standpoint, there is a basic difference between pulverised technology and FBC. While the predominant operational issues in PF boilers are ash chemistry and consequent slagging and fouling potential, in case of FBC, these attributes take a back seat since the fuel is burnt below the ash fusion temperature. Instead, the focus area in respect of FBC technology is the agglomeration tendency of the fuel and its potential to choke fuel lines.

3.15 CFBC technology has recently started scaling up in respect of both size and adoption of steam-water cycles. The largest size with operational experience at present is 460 MW at Lagisza in Poland which has employed a supercritical steam cycle for the first time in FBC. Recently a number of units upto 600 MW are being built across the globe.

3.16 In India, one of the reasons for delay in adopting the FBC technology is the relaxed emission norms.

3.17 Further, CFBC boilers installed at several plants in India have faced significant and prolonged failures.

3.18 Another barrier in respect of FBC technology is that no Indian OEM has fully grasped the nuances of the technology. Further, since three OEMs partake of the bulk of the global market, the availability of large size CFBC units at economical prices could depend on the vagaries of the market at a given time.

3.19 The economic performance of CFBC boilers is comparable to the PC based units. However, it is expected that till the environmental norms in India are tightened, FBC technology may be confined to lignite where fuel characteristics necessitate its use

4.0 INTEGRATED COAL GASIFICATION COMBINED CYCLE

4.1 Integrated gasification combined cycle (IGCC) and Underground Coal gasification (UCG) are the two technologies which are emerging as potential technologies of the future for far better environmental performance and economics.

4.2 In IGCC, coal is gasified by burning at sub-stoichiometric air-fuel ratios and the product gas is used in combined cycle configuration.

4.3 While there are a number of basic technologies and variants, the most matured IGCC technology in respect of large sized power generation is the entrained flow types.

4.4 Entrained flow type gasifiers technologies are held by GE, SIEMENS, MHI, Shell and CB&I. While MHI use air blown gasifiers, all others use oxygen blown types.

4.5 While the net efficiencies of IGCC units are comparable to the current fleet of supercritical units, the former is far superior in respect of environmental performance across all representative parameters - SOx, NOx and SPM.

4.6 Further, IGCC happens to be the best amongst available technologies for capturing mercury from coal combustion. This assumes significance in view of the fact that India happens to be one of the largest emitter of mercury from thermal power stations.

4.7 Besides, the consumptive water demand of IGCC units isonly about 2/3rd of the identical PC unit.

4.8 From operational standpoints, the biggest drawbacks of IGCC are prolonged start up time in both cold and hot conditions and relatively poor response to grid dynamics.

4.9 There are only about half a dozen IGCC units of large size currently operating across the globe.

4.10 The deterrent against widespread development of IGCC appears to be primarily its Capex.

4.11 Further, the entrained flow gasifiers may not be compatible with Indian domestic coal with significantly high ash content, unless it is washed and the ash content brought down. As for lignite, in view of high moisture, the low efficiencies will restrict them to gasifiers with dry type feeds.

4.12 The other deterrent against IGCCs in India is the relaxed norms of emission from power plants currently in vogue.

4.13 In India, an attempt to install a demonstration unit at APGENCO Vijaywada has not fructified after significant cost escalation of the project midway through the implementation stage.

4.14 However, it appears a few projects are in progress.

5.0 UNDERGROUND COAL GASIFICATION (UCG)

5.1 Underground coal gasification is essentially in-situ gasification of coal lying at depths beyond the reach of conventional mining. The process is effected by injecting the appropriate oxidant.

5.2 The method of UCG involves drilling two parallel wells, one for injection of the oxidant and the other for extraction of the product gas.

5.3 The matured UCG technology used for large capacity and for deep coal seams is the Controlled Retractable Injection Point (CRIP) method. Recently, another technology known as Single Well Flow Tubing (SWIFT), which is claimed to be more cost-economic has also been introduced, but is yet to be operationally proven.

Apart from these, in one of the potential game changers in extraction of coal from deep offshore locations, one UK Corporate claims to have developed a new technology named 'Deep Gas Winning' devoid of any environmental damage, though no details are available.

5.4 Since UCG offers production of syngas by utilising coal/ lignite at depths which otherwise cannot be economically mined, it has the potential to become one of the cost-effective methods of power generation given the sustained generation of the gas in adequate quantities.

5.5 Further, one of the major issues with the pulverised units is the disposal of ash generated from the plants. Since UCG is virtually free of ash, this is an additional attraction of the technology.

5.6 For economic UCG operation, proper siting is one of the prime requisites. The UCG needs to be planned at sites where coal is at an optimum depth from ground and has adequate seam thickness so as to produce gas with adequate heat value.

5.7 Further, preferred coal for UCG operation is low rank which shrinks while burning thus facilitating contiguity of connection from injection well to production well. Coal moisture also is preferably optimal.

5.8 Adequate reserve is another criterion for recovery of cost of drilling and site preparation.

5.9 However, by far the biggest concern about the UCG process is its potential for causing damage to the local environment.

5.10 A number of reports are available in public domain about the damage to environment that has occurred in overseas locations during UCG operations.

5.11 The main concern is the contamination of ground water aquifers by generation and seepage of benzene, toluene etc. which can have a prolonged implications. In both Australia and US, there have been incidents of seepage of these chemicals into ground water.

5.12 The other concern is subsidence of the ground above the reaction area. Normally this happens with relatively shallow depth operations.

5.13 One more aspect which has surfaced in recent times is the classification of the UCG process in respect of safety regulation, mineral or petroleum, though dominant opinion favours the former. The issue surfaced since CBM, (which is considered in the petroleum category), and UCG are extracted from identical geological locations. South Africa has recently found a way out of this by dividing the process; putting upstream extraction in the mineral regulation and downstream usage in the petroleum regulation basket respectively.

5.14 However, the opinion emerging out of the pooled experience and studies across the globe suggests that the environmental damage can be brought to a manageable extent by rational siting as well as measures undertaken during both implementation and operation of UCG processes.

5.15 Still, in spite of concerns about the potential damage to environment, UCG is steadily getting the attention of policy makers of several countries in view of its long term potential for contribution to energy security.

5.16 A number of UCG projects are being undertaken across the continents.

5.17 China is reportedly planning to exploit UCG potential in a big way with a pipeline of 30 odd projects.

5.18 In India, the Government has initiated steps for exploiting UCG by identifying five lignite and two coal blocks for auctioning. The blocks have an aggregate reserve of about 900 million tonnes.

5.19 Sustainability of UCG in India will depend on the pace of turning around of the preliminary activities such as exploratory drilling, clearances etc. in view of the involvement of multiple agencies.

6.0 OXY-FUEL COMBUSTION.

6.1 Oxy-fuel combustion is essentially removing most of the nitrogen from air and generating an oxidant rich in oxygen for firing in the boiler. Rest of the steam water is identical to a conventional coal fired unit.

6.2 As a technology, oxy-fuel combustion was an offshoot of carbon capture technology, since with a far reduced volume of CO_2, it is easy to separate CO_2 from flue gas and capture it.

6.3 Further, oxy-fuel combustion also reduces NOx formation owing to the negligible presence of nitrogen in flue gas.

6.4 However, the drawbacks of oxy-fuel combustion at the current stage of the technology are manifold.

6.5 Primarily, in view of the significant auxiliary consumption, (> 20%), the net efficiency of the unit is < 35 % and hence there is no immediate attraction in relation to competing front line technologies.

6.6 Since the technology does not have even a demonstration unit of a sizable capacity, it is not possible to predict Capex or Opex with a fair degree of accuracy; however, since the ASU is an integral part of the technology, it is expected that the Capex will be higher than a PF fired unit.

6.7 The hassles associated with combustion, especially mitigating high flame temperature on account of an oxygen rich furnace, are yet to be overcome.

6.8 Precluding Ingress of air is also a major challenge.

6.9 In India, any significant movement on adopting this technology is foreseen only after the technology matures in advanced economies.

7.0 CARBON DI-OXIDE CAPTURE AND STORAGE (CCS)

7.1 Carbon dioxide capture (or carbon capture) is essentially capturing the CO_2 emitted from coal combustion and facilitating storage at locations precluding any egress to atmosphere.

7.2 There are three main proven CCS technologies: Pre-combustion, Post-Combustion and Oxy-fuel combustion capture methods.

7.3 Pre-Combustion technology involves removing CO_2 from fuels before combustion. In this, the syngas generated from gasification is further processed in a water gas shift reactor which converts CO into CO_2 and in the process generates additional hydrogen. Because the concentration of CO_2 is higher in syngas and due to higher residual pressure, pre-combustion capture is relatively easier. However, the drawback of pre-combustion capture is that the syngas must cool down for CO_2 capture and subsequently reheated again before sending to the gas turbine.

7.4 In post-combustion capture, CO_2 is captured from flue gas exiting the combustion process. The conventional post-combustion technology employs chemical or physical absorbents both requiring low pressure steam. The steam requirement puts a significant tax on the energy efficiency.

7.5 In oxy-fuel combustion capture, as already described earlier, coal is burned with relatively pure oxygen diluted with recycled CO_2or a mixture of CO_2 and steam. Since nitrogen is removed before combustion, the flue gas will have much higher concentration of CO_2 and thus will be easier to remove. The flip side of this method is that firing of oxygen rich gas in boiler has the potential to increase local heat fluxes and compromise the metallurgy.

7.6 As of now in view of the significant cost (both Capex and Opex) involved in the existing methods of capture, CCS has not been attractive to conventional power generation. Though a number of research works are progressing across the globe, it may take a while to improve the commercial attractiveness of the CCS.

7.7 The captured CO_2 can be transported to the storage sites via pipeline or ship. Shipping has been found to be cost-effective for distances beyond 200 km.

7.8 The ideal locations for storage of CO_2 are underground abandoned mines, deep saline aquifers or geological formations.

7.9 CO_2 once stored is to be precluded from leaking back into the atmosphere. Hence monitoring is an integral part of CCS.

7.10 Based on the information available in the public domain, there has been a slowdown in the CCS projects world-wide with several projects cancelled, put on hold or scaled down, primarily from the standpoint of investment considerations.

7.11 The slowdown in Europe has happened reportedly in view of the cheaper coal available from US, which has been slowly migrating towards gas for power generation.

7.12 Further, in countries like Germany, significant augmentation of renewable energy has reduced the compulsion for fast-tracking CCS projects.

7.13 Eurelectric, the umbrella organisation for European utilities, in their response to the European Commission's Consultative paper on CCS, have expressed their apprehension about the potential mid-way shift in the operational pattern of CCS fitted utilities in a power system regime with an ever increasing share of renewables.

7.14 In the US, many of the frontline CCS projects under implementation are for utilising the captured CO_2 for downstream use like enhanced oil recovery.

7.15 Besides, in the US, the EPA, in its September 2013 release, has gone on record that 100% capture of CO_2 from CCS projects may not be economical and hence are recommending partial capture.

7.16 India has been taking baby steps in exploring the feasibility of CCS projects by way of small projects in academia with DST acting as the nodal agency.

7.17 The barriers in India, apart from economic considerations are the lack of storage locations in the hinterland. The only feasible locations are in the north east which sources are far away from the CO_2 generation.

8.0 COMBINED HEAT AND POWER AND WASTE HEAT RECOVERY

8.1 Cogeneration and Trigeneration are the basic modes of Combined Heat and Power.

8.2 As per the estimate prepared by MNRE, the current installed capacity in biomass cogeneration is about 2700 MW, in which cogeneration in the sugar industry accounts for 1600 MW.

8.3 As per MoP, the estimated additional potential for bagasse based cogen is 5000 MW.

8.4 Cogeneration efficiency is directly related to the 'heat to power' ratio. Certain industries like sugar require low pressure steam for their process and in such cases, the cogen efficiency improves significantly.

8.5 However, most of the cogen units in India have been built on low pressure – temperature steam cycles and hence cannot fully leverage the energy efficiency benefit of cogeneration.

8.6 Many cogen projects suffer from availability issues in view of inadequate technical foresight from concept to commissioning.

8.7 The environmental performances of many cogen projects have not been upto the mark for a variety of reasons.

8.8 The major barrier in the growth of the cogen projects is a lack of an institutionalised mechanism for procurement of fuel which exposes the plant owners to the vagaries of the local market.

8.9 Trigeneration is the combined production of power, heat and chilled water.

8.10 The primary application of Trigeneration is in hospitals, hotels and large commercial centres utilising chilled water based air-conditioning.

8.11 The energy efficiency of trigen system could be as high as 80% and this is a compelling reason to promote trigen in a big way.

8.12 Based on the current requirement of chilled water based air-conditioning, about 600- 700 MW of electricity based chilled water has the potential for conversion to trigen.

8.13 Further, since the growth of hotels, commercial centres and hospitals are far higher than the GDP growth, the potential for trigen is promising.

8.14 However, the main barrier in the growth of the trigen projects is the lack of availability of gas at sustainable prices. In fact, the prices have risen so high in recent years that some of the trigen projects commissioned earlier has been lying unutilised.

9.0 RENOVATION & MODERNISATION AND LIFE EXTENSION (R & M AND LE)

9.1 Mid-way through the 11th Plan period, the focus of R&M got shifted from the earlier generation maximisation to an integrated approach linking generation with energy efficiency and plant optimisation. This was necessitated in view of the realisation that the variable cost component was becoming more and more predominant over the years in view of the escalating cost of fuels of all types.

9.2 About a third of the R&M projects planned during the 11th plan could not be fructified owing to various reasons.

9.3 There appears to be no harmonious view of R&M as a concept amongst the stake-holders and this has been one of the main reasons for delay in several projects.

9.4 Some of the projects initiated were shelved mid-way through the process for want of clarity about its viability.

9.5 Further, many of the R&M projects have not met their original prediction of performance. Part of the reason appears to be lack of due diligence at least in some cases.

9.6 Going by the experience of some projects wherein the performance figures fell woefully short of the predicted figures during the launch of the projects, it is necessary that realistic projection of performance and a primary feasibility assessment based on those figures is carried out and is duly vetted by professionals with the requisite skill sets so as to preclude such cases.

9.7 Further, keeping in view the fast changing technology in the power generation sector in general and the thermal sector in particular, especially the move for adopting sunrise technologies like IGCC and A-USC technology in the near future, it will be in the fitness of things to re-look at the necessity of LE projects. This is because once the investment decision is made and project moves into the implementation phase, a mid-way re-look may not be feasible.

9.8 R & M projects expected to be launched in the immediate future may explore adopting a number of advancements that have taken place across major power plant equipments/ systems during recent times.

10.0 GAS BASED POWER GENERATION.

10.1 Combined Cycle power units based on industrial heavy gas turbines is the most common form of large capacity power generation with natural gas as fuel.

10.2 The major OEMs of the Combined Cycle Gas Turbine (CCGT) are Alstom, Mitsubishi, GE and Siemens.

10.3 The primary attributes of CCGT units are significantly high efficiency (55 to 60%), one-third of consumptive water requirements and one-tenth of land requirements in relation to an identical size PC fired unit.

10.4 Further, the environmental performance of CCGT units is also far superior with <5% of NO_x, and practically zero SO_x and SPM.

10.5 A number of advancements have been progressing in the CCGTs across all OEMs. One of the recent developments has been to develop gas turbines for firing higher temperature syngas as a prelude for improved IGCC performance.

10.6 Another major development in the CCGT arena has been improving the start-up and ramp characteristics of the units in order to fit as backup/ cycling units in grids, in line with the fluctuations in the availability of power from renewable sources (solar and wind).

10.7 Virtually all major OEMs claim ramp up rates in the vicinity of 10%. The improvements in the ramp rates have been achieved by design innovations as well as improved instrumentation and control.

10.8 Incremental cost of carbon capture from CCGT units is appreciably high in relation to an identical PC fired unit. One of the reasons is the 'base effect', i.e., the inherent CO_2 emission from the CCGT unit is less than half of an equivalent sized coal fired unit.

10.9 In India, a number of CCGT units have been installed after 2005.

10.10 Though the current installed capacity of CCGT units is about 20 GW, these stations have been operating at PLF below 50% for quite some time owing to severe shortage of gas.

11.0 OPERATIONAL FLEXIBILITY OF THERMAL UNITS WITH RENEWABLE POWER

11.1 The flexible operation of thermal units, commonly known as 'Cycling', refer to the operation of electric generating units at varying load levels, in response to changes in consumer load requirements.

11.2 This necessitates thermal units, which are lower down the dispatch priority, to act as back up units to cover the deficit as and when the grid demands.

11.3 Further, with renewable energy, many times, the peak generation may not be synchronous with the peak demand of the regional/ national grid and such scenarios put challenges on the back-up power.

11.4 Another aspect specific to the Indian grid is that, unlike many countries in Europe and US where CCGT can act fast enough to cover shortages, in India, the share of CCGT units is far lower; this makes conventional thermal units as the sole back up facility.

11.5 At present, the bulk of the renewable power comes from wind energy with an installed capacity in the vicinity of 20 GW. Grid connected Solar power is about 2 GW.

11.6 In India, major wind energy generation states are Tamil Nadu, Karnataka and Gujarat.

11.7 This aspect was studied by PGCIL in 2012 and they have suggested improvements in inter-regional transmission capacity as one of the measures to reduce grid disturbance during switchover. Recently CEA has also studied this matter with a view towards assessing the grid capability for increasing the share of renewables.

11.8 Though at present, the share of renewable sin the total energy basket is not significant, there is a need to plan for increasing the addition of renewables in due course.

11.9 Further, the control systems of thermal generation technologies are being continuously improved in respect of response to grid demand.

11.10 Apart from these, technologies for prediction of weather behaviour and smart grids are on the horizon and together these are expected to smoothen out the grid operations.

11.11 Ramp rate, part load efficiency, cycling ability, capability for operation at low load and cost of cycling are the major attributes of flexible operation.

12.0 RELATIVE SENSITIVITY OF DIFFERENT TECHNOLOGIES ON RESPONSE TO LOAD CHANGES.

12.1 Conventional coal based technologies like PC and CFBC have been found to have about 3 to 5% ramp rate per minute.

12.2 The effects of cycling on power plant equipments are more pronounced when they have to also start up and shut down and operate at minimum levels on a regular basis.

12.3 As regards the difference between the response time of supercritical and subcritical units, there appears to be no clear convergence on the matter as of now. The earlier postulate was that the absence of a steam drum in supercritical units aids faster response to load swings; however, recent studies point out that since the steam drum acts as an energy buffer, an absence of this in supercritical units can restrict the response to load changes in view of the sluggish behaviour of the pulverisers.

12.4 However, modern units have commenced incorporation of additional hardware and software to make the coal based units more responsive. Since typical supercritical stations are built in large unit sizes, economies of scale facilitate the adoption of additional features and hence it can be inferred that the future supercritical fleet will have a better ramp rate than those operating now.

12.5 CCGT units have the fastest response to the grid with about 8 to 10% per minute.

12.6 In IGCC units, though the gas turbine island has fast response, the sluggish behaviour of the air separation unit (1- 3%) drags the overall response down.

12.7 In respect of UCG, since the output of a number of production wells would be pooled together for feeding the Power generation unit, the response could be comparable to typical CCGT units.

12.8 The reduction in part load efficiencies of conventional coal based units varies in a narrow band at upper load range (~1.5 at 80% load) and drops at a steeper rate at lower loads (6%). CCGT units have a steeper reduction in part load efficiencies between 3 to 14% for the corresponding load range. In case of IGCC units, the reduction is still steeper between 4 and 10% from 100% down to 60% load.

12.9 Minimum stable load for most of the conventional coal based units is around 40%, though there rare units reportedly operating down to 25% load.

12.10 No clear demarcation has been established for the operating load range between PF and CFBC units since CFBC units are just emerging as frontier technologies in the utility generation sector. However, while CFBC units have a certain advantage in this area with low volatile fuels, with typical (sub-bituminous/ bituminous) coal, PF units appear to have a marginal advantage.

12.11 Minimum load of CCGTs is around 25%.

12.12 In case of IGCCs, the minimum load is 50%.

13.0 COST OF CYCLING OF THERMAL UNITS.

13.1 Cycling of thermal units comes with a tax on the equipment by way of increased forced outage and shortening of component life. Further, owing to the need for operating at part loads and overall lower load factors, the generation cost of cycling units could be significantly higher.

13.2 Attempt to determine the cost of cycling had commenced only recently and based on the available information, significant variation has been observed on the cost of cycling of power plant equipment. The uncertainty in accurately predicting the cost of cycling has borne out of the fact that it is difficult to segregate the cost associated with normal wear and tear from that of costs associated solely with cycling.

13.3 Based on a study carried out in the US, it has been found that the annual O&M cost of a thermal unit undergoing daily cycling could nearly triple when compared to base load operation.

13.4 The aggregate cost of cycling also depends on the mode of cycling. The estimated cost of a PF unit which cycles daily is more than twice the cost as when the unit is operating in weekend shutdown.

13.5 It is however, necessary to note that the actual cost of cycling in respect of a particular plant will depend on the composite effect of a lot of factors like age and condition of the equipments, operator skill level, actual rates of ramping up and down etc., and hence the predicted cost should be considered only on an order-of- magnitude basis.

13.6 Since flexible operation of the thermal units effectively implies running the units on cycling, as shown in the foregoing paragraphs, significant escalation in the generation cost on account of higher cost of capital (apart from incremental cost of cycling) will occur. This will obviously call for rejigging the tariff.

14.0 FLEXIBILE GENERATION WITH COMBINED HEAT AND POWER.

14.1 Flexible generation using a combined heat and power model has not been found to be a viable proposition for Indian condition for several reasons.

14.2 As the efficiency of power generation units (mainly turbines) drops down concurrently with the size, unless the quantum of steam export can offset the incremental loss in efficiency, it may not overall be a suitable substitute for larger units.

14.3 The flexible generation will be economic only with Trigeneration application as of now provided an adequate gas supply is available at economic prices in a sustained manner.

14.4 Further, the overall performance parameters of smaller units on both the economic as well as the environmental front would be inferior to larger units.

15.0 GENERAL ASPECTS RELATED TO TECHNOLOGY SELECTION IN INDIA

15.1 The primary attributes of the different technologies discussed above have been tabulated as an annexure herewith.

15.2 It has been observed that the emission norms in India, when compared to many major economies including China, have been very liberal and this appears to have acted as a roadblock to the development of environmental friendly coal based technologies in India.

15.3 The following tabulation of a broad comparison of the power plant emission limits from overseas power stations along with the current norms prevailing in India is a pointer to the stark gap that has the scope to be filled.

PARAMETER (mg/ Nm^3)	US	EU	CHINA	INDIA
NOx	117	200(after 2015)	100	- (actual 300 - 500)
SOx	160	15 - 200	100	- (actual ~ 1000)
SPM	22.5	30 - 50 (100 for lignite)	20 - 30	150*
Mercury	0.001	0.03	0.03	-

* Many large stations are following 50 mg/ Nm^3

15.4 It is observed that technologies like CFBC have the inherent capability to significantly reduce NOx and SOx emissions. Further, IGCC is one of the best technologies for mercury capture.

15.5 On the extent of emission across technologies, it has been found that NOx is typically in the highest range with PF technology and lowest with CCGTs.

15.6 In case of PF technology, NOx is found to be almost constant for load down to 80%; below this, it has been found to decrease marginally(8- 10%). In respect of FBC, it has been found that the minimum value is reached in the vicinity of 80% load. In case of gas turbines, the NOx has been found to decrease with the load in view of lower peak flame temperature.

15.7 In respect of SOx for PF boilers with FGD, no significant change has been observed with load variation. For FBC, marginal improvement has been observed in sulphur retention for lower load due to lower fluidisation velocities and consequent increase in residence time.

15.8 Particulate matter (SPM) emission has been found to improve for ESPs at lower loads.

15.9 Recently India has been facing a shortage of coal for feeding the projects in the pipe line. As per the projection of the MoP for the 12^{th} plan period, the constraints of local mining capacity may force the country to import a substantial quantity of coal with potential drag on the forex reserves. A point worth noting in the context is that the cost of imported coal reaching the Indian coast at a given time is vulnerable to the vagaries of the international demand-supply as well as the relative strength of the Indian currency. Both of these factors have seen spikes in the past.

15.10 Coal based plants require significant contiguous land mass and substantial make up water. The consumptive water requirement for the 40 GW thermal generation capacity projected for the 13^{th} plan is 800 million m^3 per annum. The cumulative consumptive water requirement for thermal power generation in the country by the end of the 13th plan is expected to reach the vicinity of 5000 Million m^3, close to the total hold up capacity of some of the biggest dams in the country. This can have serious consequences on the perennial availability of water for power generation in case the inflows during monsoon seasons fall short.

15.11 Though the air cooled stem condensing system had been found to be not cost-economic for Indian conditions in view of higher Capex and energy tax, keeping in view the depleting ground water reserves in the country, a sense of priority demands a critical re-visit on this issue.

15.12 Improved coal washing and lignite drying methods are another area needing attention. With reduced ash content, environmentally friendly technologies like IGCCs can be deployed with matured gasifier technologies.

16.0 IGCC AND ADVANCED ULTRASUPERCRITICAL UNITS - EXTERNALITIES IN COST MATRIX FOR INDIA.

16.1 It is presumed that large scale development of IGCC and A-USC units in India will call for an extensive use of nickel based super-alloys which need to be imported to the country even if the components are manufactured here.

16.2 A-USC units require significant quantities of nickel based super alloys. An order of magnitude estimate is about 2000 tonnes of super alloys for a typical 800 MW unit.

16.3 Nickel based alloys are not only expensive, but their cost trends shows significant spikes in prices during increased global industrial activity.

16.4 The production of the base metals forming these alloys is monopolised by a very few countries with large political and economic power and they have the capacity to tilt market dynamics if the opportunity presents itself.

16.5 Further, the cost of A-USC units in India will also depend on the developments overseas in respect of adaptation.

16.6 Nickel based super alloys are also extensively used in Gas turbines. In fact, with the gas turbine trying to breach the 1700^0C barrier, far greater quantities of nickel based alloys will be used in their manufacture.

16.7 China has been ramping up efforts in fast-tracking A-USC units. Similarly, Japan, after the Fukushima accident, is also mulling its options for power generation; one of the alternatives on the table is totally jettisoning nuclear power in which case, they will be forced to fall back on thermal generation.

16.8 In case IGCC/ A-USC technology need to be imported, another aspect that can compound the escalation in cost is the risk perception of the country from global suppliers in view of several developments. In the recent past, some large scale CCGT projects were cancelled after placement of order with overseas contractors. Further, Indian currency also, after a relatively stable period, has again started showing signs of volatility. These factors also have the potential to increase the cost of materials and equipments being imported.

16.9 However, in the US, with the migration to gas based generation, there is a possibility that IGCCs projects may get scaled down in which case the component vendors may look for alternative markets with attendant thaw in the prices.

16.10 Overall, still, it is projected that the A-USC units would be costlier than any estimate prepared based on current metal prices. As for IGCC units, though current costs themselves are high, (except in China), no appreciable thaw in the costs are projected in the medium term.

17.0 AVAILABILITY / RELIABILITY AND MAINTENANCE ASPECTS:

17.1 Both the Availability, (total available hours – sum of planned and forced outages), and the Reliability, (total available hours – forced outage), of power plants have been rising steadily in view of the modern tools available for on-line diagnostics and corrective action.

17.2 In India, during the past 20 years, forced outage of thermal plants has come down by 50%.

17.3 On a relative basis, globally, the forced outage of coal based units has been found to be marginally higher than CCGT units.

17.4 The maintenance of thermal power plants has evolved over the decades from a breakdown maintenance regime employed in the initial period to preventive, predictive and performance driven maintenance applied nowadays.

17.5 On a relative basis, IGCC availability has been lower when compared to PF, FBC and CCGT units.

17.6 Amongst the three major technologies, on a global scale, O&M cost of PF units have been found to be the lowest while that of IGCC are the highest with CCGTs occupying the intermediate range.

18.0 SMALLER Vs. LARGER STATIONS: AVAILABILITY AND ECONOMICS

18.1 Smaller power stations with lower unit sizes have a statistically higher availability.

18.2 However, from the standpoint of economics (Capex, Opex, land, water), and environmental performance, smaller stations have major disadvantages.

18.3 Further, on a broader level, since the cumulative capacity of thermal power has been progressing at a fast pace over the last few years, the marginally lower availability that may result due to outage of a couple of units across the national electricity grid is not likely to affect the power availability significantly.

18.4 However, building large power stations requires huge contiguous land area as well as a significant quantity of consumptive water; besides, many locations may need building of power transmission corridor and railway connectivity. Many times, this may involve moving human settlements, clearing forests and sometimes even unsettling bio-diversity. Together, sometimes these can affect local habitat and has the potential to create socio-political conflicts.

BROAD COMPARISON OF THERMAL POWER GENERATION TECHNOLOGIES

Sl. No.	PARAMETER	PULVERISED FUEL FIRED				BFBC	PFBC	CFBC (SUBCRIT)	CFBC (SUPCRIT)	Oxy-Fuel	IGCC	UCG	OCGT	CCGT	CHP	R&M
		SUBCRIT.	SUPERCRIT.	USC	A - USC											
1	GROSS EFFICIENCY, HHV %	35- 37 %	39	40	45 - 47	<30	Technology outdated; no data on recent plants available	33- 34	35-36	44-46	47-50	50 - 55	36--39	55 - 57	Depends on steam to power ratio	30 – 34%
2	TYPICAL SIZE , MW	250 - 600	660/ 800	> 800	> 800	10- 40		250	> 400	> 500	500	500	250	500	small	250
3	FUEL/ SIZE mm	Pulverised Coal	Pulverised Coal	Pulverised Coal	Pulverised Coal	Crushed coal / 6- 10		Lignite / 6-10	Lignite / 6-10	Pulverised coal	Syngas	Syngas	Natural gas	Natural gas	Coal/ Gas	Pulverised Coal
4	AUX POWER , %	5.5 – 10	5	5	4.5- 4.8	10-12		8	6 - 6.5	22- 24	16- 22	2	1.0	1.5-2	Varies	8 - 10
5	NET EFFICIENCY HHV %	31.5 - 35	37	38	43- 45	25-27		30.5 - 31	33- 34	34 - 35	37- 40	49-54	36-39	54- 56	varies	28- 31
6	START UP TIME, HRS															
i	COLD	6 - 8	7 - 10	7 - 10	Should be higher	Generally used for captive applications; no representative data available.		4 - 6	Only one unit operating at present in the world. However, generally all attributes expect to be superior to subcritical CFBC, except cycling capability which could be marginally inferior to supercritical PC. Capex and opex expect to be marginally higher for FOAK units	40- 50	6 0-80	Identical to CCGT	80- 100 minutes	2	Depends on Technology	Expect to be marginally inferior to new subcritical units
ii	WARM	3- 4	4 - 5	4 - 5				2 - 3		Technology still under pilot stage ; No representative data available.	-		30- 40 minutes	1.5		
iii	HOT	1.5 - 2	2 - 3	3 - 4				1.5- 2			6 - 8		10- 20 minutes	0.5		
7	RAMP UP RATE, % / MIN	3 - 5	2 - 8	2 - 7	Should be Lower			2 - 6			1 - 3	Marginally lower than CCGT	8 - 12%	2 – 8 %		
8	CYCLING ABILITY	Moderate	Moderate	Moderate	Moderate			Marginally Lower than PC			Lower than PC	Yes for large units	Best amongst all technologie s	Good.		
9	EMISSION															
i	CO_2, kg/ kWh	0.94 - 1.2	0.9	0.88	Should be ~ 20% lower than SC units	Generally fairly higher than PF units except SO2		1- 1.3			0.8 – 0.88	In close range with CCGTs	0.85 – 0.9	0.5 - 0.6		
ii	SO_X, g/ kWh	4.0	3.3	3.2				0.5-1			0.7		negligible	negligible		
iii	NO_X, g/ kWh	1.2	1.0	0.97				0.2- 0.3			0.4		0.1 - 0.15	0.07 - 0.1		
iv	SPM g/ kWh	0.15	0.12	0.115				0.2			0.04		Negligible	Negligible		
10	WATER DEMAND, M^3/ MWH	2.4 - 3.0	2.2- 2.5	2.1- 2.2		3.5 -4		3-.3.5			1.6 -2.0	Higher than CCGTs, but lower than PF technology	Negligible	0.8 - 1.0		Marginally higher than new units
11	LAND, ACRES/ MW	1.42 (2 x 500 MW)	1.04 (3 X 660 MW)	1.04 (3 X 660 MW)	Marginally lower than SC units	2.5 - 5		1.6- 1.6			Comparable to PC unit	Identical to CCGT	Very small	0.15		No additional land required
12	Capex , Rs million/ MW	55 - 65	55- 65	70-75 (2 x800 MW)	85 – 105 (5 x 800 MW)	70 - 80		60 - 70			100 - 200	Site dependent	20 - 25	40 - 45	55- 80	25 - 35
13	Opex, Rs Million/ MW year	1.5	1.5	> 1.5 for FOAK units	Expect to be higher for FOAK units	> 2		1.5- 2.0			Expect to be significantly higher for FOAK units		1.5 – 2.0	1.5- 1.8	Varies	Expect to be higher than new units
14	MATURITY	Mature	Mature	Mature overseas	Development stage	Mature		Mature		Not Yet.	Not yet	Not yet	Mature	Mature	Mature	Mature

Expected range of Cost of Generation, CAPEX and OPEX, Land requirement and water requirement for Supercritical CFBC

Cost of Generation Rs/ kWh	Domestic Coal: 2.3 – 2.8	Imported Coal: 3.3 – 3.8
CAPEX Rs Million/ MW	70- 80	65- 75
OPEX Rs Million/ MWYr	Domestic Coal: 1.7 - 1.8	Imported Coal: 1.7 - 1.8
Water Use M3/ MWh	Domestic Coal: 2.2 - 2.5	Imported Coal: 2 – 2.2
Land Use Acres/ MW	Domestic Coal: 1.1 1.2	Imported Coal: 1 – 1.1

Net efficiency, Cost of Generation, OPEX and Emissions performance (CO2, NOx, SOx, SPM) of domestic coal and imported coal for all technologies.

		Cost of GenerationRs/ kWh	OPEXRs Million/ MWYr	CO2 kg/ kWh	NOx g/ kWh	SO_2g/ kWh	SPM g/ kWh	Net Efficiency %
Supercritical PC	*Domestic Coal:*	2.1 – 2.6	1.5	0.94	1.0	3.3	0.12	37
	Imported Coal:	3.3 - 3.7		0.88			0.1	38
Supercritical CFBC	*Domestic Coal:*	2.3 - 2.8	1.7 -1.8	0.9	0.2 - 0.25	0.4 – 0.8	0.12	37
	Imported Coal:	3.4 - 3.8		0.88			0.1	38
Ultra supercritical PC	*Domestic Coal:*	NA	USC PCs are expected to be of minimum 800 MW size for cost economic design. With Indian domestic coals, 800 MW size prototype boiler has not been developed so far owing to unwieldy physical size compatible with the coal characteristics.					
	Imported Coal:	3.2 – 3.6	1.5	0.85	0.96	3.2	0.1	41
IGCC	*Domestic Coal:*	NA	IGCC is not expected to be fired by Indian domestic coal in view of significant ash and hence potential for compounding to the already inferior reliability associated with the technology.					
	Imported Coal:	4.0 – 5.0	2.3- 2.8	0.8 – 0.9	0.4	0.7	0.04	37- 40
OCGT	*Domestic Gas:*	\$4/ MMBTU : Rs 3.3/ kWh \$8/ MMBTU : Rs 5.8 / kWh	1.5 - 2.0	0.8 - 0.9	0.1 - 0.15	Negligible	Negligible	36- 39
	Imported Gas:	\$10/ MMBTU : Rs 7.1/ kWh \$16/ MMBTU : Rs 11 / kWh						
CCGT	*Domestic Gas:*	\$4/ MMBTU : Rs 2.7/ kWh \$8/ MMBTU : Rs 4.5 / kWh	1.5 – 1.8	0.5 - 0.6	0.07 - 0.1			54- 56
	Imported Gas:	\$10/ MMBTU : Rs 5.4/ kWh \$16/ MMBTU : Rs 8 / kWh						

Notes:

1. The cost of generation for coal based technologies have been estimated based on the range of current market prices in respect of both domestically mined and Imported coal varieties.
2. The sulphur content in the Domestic and Imported coal varieties have been taken as 0.3- 0.5 % and 0.6 – 0.8 % respectively.

- All performance indicators have been brought to Indian conditions with ambient temperature around 35 °C.
- Gross efficiency is determined based on a 3% margin on rated design value, based on typical Indian coal.
- For CFBC, the values correspond to lignite, for both subcritical and supercritical.
- For A-USC, the lower and upper range of efficiencies are for 300 bar/ 700^{0}C/ 720^{0}C (EU Concept) and 350 bar/ 735^{0}C / 760^{0}C (US Concept) steam cycles respectively calculated for Indian conditions. Performance figures for A-USC are estimated values.
- For UCG, the performance figures mentioned are for the power island, except in respect of water demand.
- For R&M, only coal / lignite based subcritical units have been considered here.
- CCS is not a power generation technology *per se;* hence not listed.

Section I
Coal / Lignite Based Technologies Operationally Matured

1.0 INTRODUCTION

1.1 About 70% of utility power generation in the country is through solid fuels, sub-bituminous coal and lignite, and hence, as of now, it remains the backbone of the generation sector.

1.2 Lignite based power plants are located primarily in Tamil Nadu and Gujarat; besides, a few are being developed in Rajasthan.

1.3 Unit sizes and station capacities: Till 2011, the largest unit size in operation in India was 500 MW; however, a fast migration into larger sizes of 660 MW and 800 MW are currently underway in the country across all power utilities. Further, competition in the sector is compelling developers to leverage the economies of scale and construct large station sizes many of them exceeding 2000 MW size.

2.0 COAL PROPERTIES AND ITS IMPACT ON EQUIPMENT DESIGN.

2.1 A Brief introduction of the primary characteristics of coal and its impact on the design of power plant equipment is covered here.

2.2 Fuel quality has a major impact on the performance of the boiler and thus needs to be factored in while designing the boiler and its auxiliaries. Major factors which have a bearing on its performance are as follows.

2.3 Fuel Ratio or Fixed carbon to Volatile matter (FC/ VM) ratio:

2.3.1 This gives a measure of the combustibility of the coal and influences the design of the furnace and fuel firing system.

2.3.2 Normally, the fuel ratio increases as the rank of the coal goes up. Anthracite coal has the highest fuel ratio and thus the poorest burning characteristics, entailing a special firing system like arch firing (or down-shot firing) so as to increase the residence time (towards reducing the un-burnt carbon and in turn improving boiler efficiency). Lignite, on the other hand has a very low Fuel ratio in view of significantly high proportion of volatile content.

2.3.3 Besides, a high fuel ratio reduces the stable operation window of the boiler E.g.: Boilers with anthracite coal cannot be designed for stable loads below 60% capacity.

2.4 Moisture:

2.4.1 The primary impact of moisture content is reduction of boiler efficiency. Normally, moisture content at moderate levels upto 15% does not affect the hassle- free operation of the boiler; however, moisture content beyond 25 % has the potential to affect the operation of the boiler.

2.5 Sulphur Content:

2.5.1 Sulphur has a major effect on the performance of the boiler owing to its tendency to form H_2SO_4 in combination with moisture and excess air. In fact, high sulphur fuel has a multiple impact on power plant operation since it can directly and indirectly affect the operational cost of the boiler and upfront increase the Capex of the power plant.

2.5.2 In order to maintain the flue gases above acid dew points, the boiler exit temperature is raised which results in reduced efficiency of the boiler.

2.5.3 But sulphur can also produce corrosion of water walls in the reducing conditions normally prevailing at burner belt areas.

2.5.4 Beyond a threshold, the sulphur content necessitates incorporation of FGD plant which increases Capex significantly and apart from an increase in Opex.

2.5.5 It needs to be mentioned that in some parts of the world, the penalty from regulators on SOx emitted to the atmosphere is significantly high. Hence, the sulphur content in coal has a major bearing on its price.

2.5.6 Most of the international coal contracts have standard clauses setting the penalties for increased sulphur content beyond a threshold.

2.6 Ash Content:

2.6.1 Ash content affects the boiler and auxiliaries in many ways. From an energy loss perspective, it has multiple impacts: On one hand, it increases the direct auxiliary consumption of the plant by way of a larger sized coal and ash handling system; secondary increase in the auxiliary consumption is in view of the larger cooling water (and hence water chain). On the other hand, it reduces the boiler efficiency in view of significant heat lost in ash.

2.6.2 Besides these impacts on the net energy, ash also has a major bearing on the furnace and flue gas path designs. Studies have found an exponential co-relation between ash loading of the boiler and tube erosion as the ash content rises; the transverse clearance between the heat transfer tubes needs to be increased for precluding/ mitigating fouling. This will result in increased dimensions of the heat transfer path and concurrent increase in cost.

2.7 Ash chemistry:

2.7.1 This is, by far, the most significant factor influencing the slagging of the furnace and fouling of the convection surfaces and in turn the frequency of downtime. Till recently, ash fusion temperatures had been considered as the primary indicators of slagging potential; however, recent global practices indicate that utilities capture the ash chemistry of all possible ranges of coals while preparing the boiler specification. Nowadays, terms like slagging index, base to acid (B/A) ratio, silica%, alkalis etc. have been used as input for boiler performance modelling.

2.7.2 In the context, it needs to be mentioned that two constituents of the ash have a contrasting impact on the boiler performance – Silica (SiO_2) and Iron Oxide (Fe_2O_3). While the former harms the milling system and boiler tubes because of its erosive potential, the latter contributes to furnace slagging and fouling of heat transfer tubes.

2.7.3 However, in general, relationship amongst ash constituents is far more complex than straight acidic/basic relationship e.g.: when CaO is high, presence of SiO_2 has been found to lower the ash melting point. This is a subject of continuing research especially in view of the increasing size of the furnace and compulsion of utilities to look for fuel diversity in order to remain competitive.

2.8 Ash fusion temperatures:

2.8.1 The ash fusion temperatures (AFTs) reflect the composite chemistry of the ash and have a significant impact on the design of the boiler and in turn its cost. Closely related to ash chemistry, these are also used to establish the degree of slagging. Typically, three values, viz. initial deformation temperature (IDT), hemispherical temperature (HT) and fluid temperature (FT), are considered representative. These are determined based on tests as per established procedures like ASTM D 1857as explained hereunder.

2.8.2 IDT is the temperature at which the ash starts showing initial signs of softening up and is defined as the temperature at which the tip of the cone (of fuel prepared for test) begins to deform.

2.8.3 HT is at which the height of the cone equals half the cone's width.

2.8.4 FT is the temperature at which the melted cone spreads into a flat layer with a maximum height of 1.6 mm.

2.8.5 Nowadays, the composite properties of ash chemistry as well as the ash fusion temperatures are used to predict the slagging and fouling behaviour of fuels.

2.9 Hardness:

2.9.1 Hardness relates to the property of coal against resistance to abrasion and is defined by the Hard grove Grindability index (HGI). This also reflects the chemical property of ash; while SiO2 is considered as the primary element contributing the hardness, the actual hardness and abrasiveness of coal depends on the form of SiO2, i.e., the proportion of alpha quartz and its structure.

2.9.2 Hardness directly impacts the pulveriser capacity during milling and also causes the erosion of heat transfer tubes. In India, many of the coal seams in Mahanadi coal mines have been found to contain alpha quartz and have affected boiler operations significantly.

2.9.3 Typical analysis of Indian domestic coal and lignite and imported coal are furnished below:

TABLE 1.1 COAL/ LIGNITE ANALYSIS

SL. No.	CHARACTERISTICS	DOMESTIC COAL	LIGNITE	IMPORTED COAL
1	PROXIMATE ANALYSIS(%)			
	Total moisture	10 - 16	40 - 55	6 – 15
	Volatile matter	22 - 35	22 – 35	25 – 45
	Fixed carbon	19 - 34	27 - 35	40 - 60
	Sulphur	0.3 – 0.5	0.2 – 2	0.6 – 0.8
	Ash	34 – 48	3 - 12	6 – 10
	HGI	45 – 60	90 – 150	40 – 55
2	ASH ANALYSIS (%)			
	SiO_2	40 – 60	10 - 50	35– 70
	Al_2O_3	20 – 30	3 - 27	10 - 30
	TiO2	1 - 2	Upto 1.5	0.5 - 6
	Fe_2O_3	2 - 10	3 - 15	3 - 15
	CaO	0.5 - 5	5 – 30	0.1 - 10
	Na_2O	0.2 - 3	Upto 2	0.1 - 2
	K_2O	0.08 – 0.65	Upto 0.05	0.3 - 2
3	ASH FUSION			

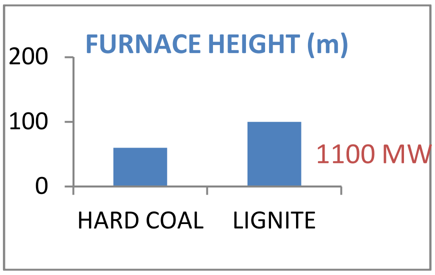
SL. No.	CHARACTERISTICS	DOMESTIC COAL	LIGNITE	IMPORTED COAL
	TEMPERATURES (°C)			
	IDT	1100 – 1300	1050 - 1200	1050 - 1300
	HT	1150 - 1400	> 1200	1200 - 1400
	FT	1250 - 1400	1350	1250 - 1500

2.9.4 The impact of properties of coal on the design of the boiler can be seen from the following example from some of the large capacity boilers erected in recent times in Germany[1,2]

TABLE1.2: ILLUSTRATION OF IMPACT OF COAL PROPERTIES

Sl. No.	PARAMETER	PLANT	
		Ps Datteln	Ps Neurath
1	Plant Rating, MW	1100	
1	Fuel	Bit. Coal	Lignite
2	Boiler capacity, TPH	2968	2898
3	Steam pressure	285/59	272/ 56
4	Steam temp	600/ 620	600/605
4	Fuel flow, TPH	335	818
6	Flue gas flow, kg/ hr	2.9×10^6	3.35×10^6

2.9.5 The significant implication of fuel properties on the physical size of the boiler can be seen from the following charts:



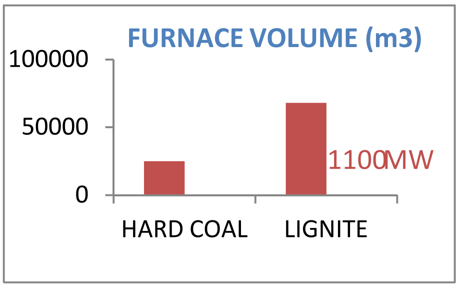


CHART 1.1: ILLUSTRATION OF IMPACT OF COAL PROPERTIES

2.9.6 The significant increase in the dimension of the lignite furnace can be attributed primarily to the necessity of keeping the furnace heat release rate low so as to preclude slagging. Of course, lignite properties vary across regions. In fact this is the primary reason for the increased cost of the lignite fired units.

2.9.7 Augmenting the boiler cost will be the cost of fuel handling systems which have to carry almost double the quantity of fuel in view of the high proportion of moisture and sometimes ash also.

2.9.8 Hence typically, Capex of Lignite fired plants will be about 5 to 10 % more relative to the equivalent rated coal based units. This even after factoring in the softer nature of lignite with attendant lower duty for crushers and pulverisers.

2.10 Fuel properties of Indian Coals and its impact on the design of boiler and auxiliaries:

2.10.1 Typical Indian coals are characterised by medium volatiles and moisture. Ash chemistry is tilted more towards erosive (higher silica content) than corrosive, except a few mines in WCL where Fe_2O_3 upto 10% have been observed. In fact, many coal seams in MCL have been found to have significant amount of alpha quartz which is the most common form of SiO_2.

2.10.2 However, by far the singular factor which keeps Indian coal stand out is the ash content itself which is typically in the vicinity of 40%. In respect of lignite, the predominant content apart from moisture is marcasite. Published literature has found that the erosive potential of the coal is directly proportional to the ash to carbon loading and exponentially related to the flue gas velocity.[3]

2.10.3 The following order-of-magnitude comparison between coal from domestic mines and overseas mines for a 500 MW unit should give a clearer picture about the impact of the ash content in Indian coal:

TABLE 1.3: IMPACT OF ASH LOADING IN COAL

Sl No.	Parameters	Indian Domestic Coal	Overseas Coal	Remarks
1	Heat energy in steam supplied to turbine M kcal/ hr	1027	1027	In a realistic scenario, because of improved heat rate of overseas turbines, actual heat added would be marginally lower.
2	Boiler efficiency %	87	90	
3	Heat input to boiler	1181	1141	
4	Coal GCV kCal/ kg	3300	6000	
5	Coal fired TPH	358	190	
6	Ash content %	40	10	
7	Ash generated	143	19	
8	Fly Ash @ 80%	115	15	
10	Fly ash loading ratio between Indian coal fired boiler and overseas coal fired boiler	~ 8	Base	

2.10.4 From the table above, the impact of high ash low GCV Indian coal can be seen.

2.10.5 Years of experience has resulted in utilities and designers adopting flue gas velocities in Indian boilers in the vicinity of 10 m/ s against 16- 18 m/ s prevalent in typical overseas plants. An offshoot of this aspect is specifying tubes without fins (bare tubes) for economiser which is again a departure from those adopted for typical overseas boilers.

2.10.6 Special characteristics of Lignite for FBC application: There are some basic difference between PF technology and FBC when it comes to the characteristics of lignite. While the predominant operational issues in PF boilers are ash chemistry and fusion temperatures and consequently slagging and fouling potential, in FBC applications, these properties take a backseat since the fuel is normally burned below the AFT's; instead, the focus area is the agglomeration tendency of the lignite in the bed and potential blocking of fuel lines.

3.0 TECHNOLOGY IN INDIA AS ON DATE

3.1 At present, utility power generation using solid fuels are based on the following technologies:

3.1.1 Pulverised Fuel (PF) based: All coal based plants are based on PF. As for lignite, all boilers installed till recently are of PF type.

3.1.2 Neyveli Lignite Corporation (NLC) has introduced Circulating Fluidised Bed Combustion (CFBC) technology recently for unit sizes 125 MW and 250 MW. The first 250 MW boilerwas commissioned in the first quarter of 2012 calendar year.

3.1.3 All PF boilers operating in India till 2010 are of subcritical rankine cycle technology. However, at present, bulks of the projects being built are those using supercritical technology. In fact, in view of the superior efficiency and reduced carbon footprint, policymakers appear to encourage only supercritical technology for power stations planned from 13th 5 year plan onwards.

3.1.4 A detailed description on primary attributes of various technologies using solid fuels are described as follows.

4.0 SUBCRITICAL AND SUPERCRITICAL / ULTRA-SUPERCRITICAL PF BASED UNITS – PRIMARY ATTRIBUTES

4.1 Since both technologies use Pulverised fuels, there are a number of common attributes for these technologies; a few major attributes are listed below.

4.2 The fuel feeding system, air and flue gas system, and steam water system upto the economiser outlet and beyond the evaporator are similar in design and construction. However, in case of supercritical units, the condensate polishing system is used on-line (full flow), whereas in case of subcritical, typically, only 50%flow is put on-line.

4.3 There is practically no change in the fuel handling system and ash removal system.

4.4 Further, design and construction of the turbine island are also similar, the difference being in the configuration of the HP/ IP and LP turbine modules and in the number of regenerative heaters. But these are primarily size and not technology related attributes. In case of LP turbine, supercritical units of higher sizes sometimes employ titanium blades in view of long lengths required concurrent with the large steam flows.

4.5 Similarly, arrangement of milling, and firing (tangential or wall firing) burner layouts are also identical between both technologies.

4.6 The main difference inside the boiler will be furnace construction and materials thereof. Whereas subcritical boiler employs simple water cooled membrane panels interconnected with drum by way of down-comers and risers, supercritical furnace construction is more complex.

4.7 Materials are another major area of difference. Whereas subcritical units need only carbon steel tubes for water walls, the complex temperature profile of the supercritical units calls for alloy steels in furnace. Further, the superheaters and reheaters also are predominantly of alloys steel construction. Overall, alloy steel requirements for subcritical units are fairly limited.

4.8 Another area with a basic difference between subcritical and supercritical is the make-up water required for steam-water cycle. Absence of a drum makes supercritical units virtually devoid of blowdown and hence the continuous need of make-up water. However, some amount of water will be required during every start up and to cover system leakages.

4.9 Still, another major difference between subcritical units and supercritical units is the relation between metallurgy and the steam cycle selected. Since for large size subcritical units, nowadays the steam temperatures commonly used are 540/ 568 °C, the metallurgy is by and large standardised. However, this is not the case with supercritical technology which is progressing towards higher and higher temperatures (and pressures, though to a slower extent). In supercritical units, the predominant operational issues which decide the metallurgy are fire side corrosion and steam side oxidation potential.

5.0 SUBCRITICAL PULVERISED FUEL BASED UNITS

5.1 Basic description: Subcritical rankine cycle is characterised by a steam drum acting as the fulcrum of the steam-water circulating system. The feed water, after passing through the regenerative feed water heaters and economiser tubes, enters the steam drum. From there the water is let down to the water walls through large diameter downcomers. The water, after absorbing heat from the furnace water walls, rises by natural gravity (caused by density difference) or assisted by circulating pumps. Part of the water thus becomes steam and gets out of the drum. The rest of the water returns to the water walls and the cycle repeats.

5.2 Though subcritical units can theoretically operate close to the critical pressure (221 bar), industry experience has found that operating pressures above 180 bar gives diminishing returns on the cycle efficiency. Nowadays, the accepted steam cycle parameters for large sized units are in the vicinity of the following values:

- Pressure at SH outlet : 170 bar
- Temperature at SH outlet : 540^{0}C
- Temperature at HRH outlet : 540^{0}C / 568^{0}C

5.3 Typical configuration of the for a large sized subcritical (500MW) unit:

TABLE 1.4: TYPICAL CONFIGURATION OF A LARGE SIZED SUBCRITICAL UNIT.

Sl. No.	DESCRIPTION	CONFIGURATION
1	TURBINE BLOCK	
	Turbo generator configuration	HPT, Double flow IPT + Double flow LPT
	No. of feed water heaters	6 (3 Nos LP; 2 Nos HP, one contact type)
	Feed Pumps	3 Nos
	Condensate Pumps	2/ 3 Nos
2	BOILER ISLAND	
	Firing	Tangential
	No. of mills	6- 8

5.4 Typical performance parameters for Indian Coal and climatic conditions:

TABLE 1.5: TYPICAL PERFORMANCE PARAMETERS OF A LARGE SIZED SUBCRITICAL UNIT

Sl. No.	Description	Value
1	Boiler efficiency %	
	Indian coal	87
	Neyveli Lignite	77
2	Turbine Cycle heat rate, kCal/ kWh	1950 (@ 33^{0}C CW Temp)
3	Auxiliary power consumption, %	5.5 – 10 (Upper range for mid-size lignite based units)
4	Environmental performance	
	CO2	0.94- 1.2 T/ MWh
	SO2	300 – 500 ppm
	NOx	200- 300 ppm
	SPM	50 – 150 mg/ Nm3
	Consumptive Water Requirement	2.4- 3.0 M^3/ MWh

5.5 Start –up time, ramp up rates and load response

5.5.1 Start-up time duration: Typical start up time periods for subcritical units are:

TABLE 1.6: TYPICAL START UP PERIODS FOR SUBCRITICAL UNITS

Start up	Time (hours)
Cold	6 - 8
Warm	3 - 4
Hot	1.5 – 2

5.5.2 Ramp up rates and response to load changes

The ramp up rates normally specified for Indian thermal power plants are 3% per minute. It appears that this by and large corroborates the findings of various surveys and studies done about power plant dynamic behaviour in overseas plants also. In some cases, it may be possible to improve the ramp up rates to 5% per minute.

5.6 Future of Subcritical technology in India :

5.6.1 Subcritical units have been the backbone of the country's thermal power generation. Unit's upto 500 MW have been in operation for more than 15 years. However, as of now, only one manufacturer (BHEL) has the capacity to manufacture major equipments like boiler, turbo-generator and critical auxiliaries.

5.6.2 Recently, in order to push up more efficient supercritical technologies partly to improve energy security and partly to meet international obligations under climate change mitigation, the government had taken an in-principle decision to phase out subcritical units by the end of the 12th plan. In fact, going by the current trend in the utility power generation sector, the bulk of the new investment happening in the sector is in the supercritical technology space.

5.6.3 However, a number of subcritical units have recently been installed and some large capacities of 600 MW are in the construction stage; hence subcritical units are going to be in service for at least next 15 years or more.

6.0 SUPERCRITICAL/ ULTRASUPERCRITICAL PF BASED UNITS

6.1 At the outset, it is to be kept in view that Ultra-supercritical units are an uprated variation of classical supercritical units, with steam temperature above 600 bar but (so far) not exceeding 620 °C. Hence, both these are treated together for the discussion in this paper. Advanced Ultra Supercritical (A-USC) technology, which is still evolving is dealt with at the end separately.

6.2 Basic description:

6.2.1 Supercritical units differ from their subcritical counterparts primarily in the following areas.

6.2.2 Furnace design: The design of the furnace needs to be compatible with the once-through nature of the water-steam system. Unlike subcritical units, where at all loads in the normal operating regime, the water circulating in the furnace wall tubes ensures there are no 'outliers' in the tube metal temperatures, in case of supercritical units, the furnace needs to be designed appropriately, in view of the pressure-temperature-enthalpy regime of steam-water.

Two well established designs are spiral wall for the lower furnace and vertical wall for upper furnace, the second with Vertical low mass flux for the complete furnace.

6.2.3 Steam- water parameters: Supercritical units installed in the country in the initial phase have used fairly low steam temperatures E.g.: NTPC Sipat has used 540/ 568 °C at superheater and reheater outlets respectively. However, many units planned subsequently have used 568/ 568 °C and recent projects have gone further to 568/ 596 °C steam temperature. In units installed overseas, it has been found that the steam temperature has been progressively increasing with new units at the same stations. The progressively higher temperatures in the supercritical water-steam circuit calls for compatible materials across all heat transfer sections.

6.3 Primary Technological Attributes:

6.3.1 The feed water, after passing through the regenerative feed water heaters and economiser tubes, enters the furnace and gets out of the system as steam. From the furnace outlet, steam goes through the different stages of superheaters (and inter-stage attemperators) and finally exits the boiler. Since the flow is once-through, there is no recirculation in the evaporator circuit.

6.3.2 Complexity of furnace design in supercritical boiler: The once through flow makes supercritical furnace delicate to design in the current operation mode being practiced, sliding pressure operation, for supercritical units in view of the thermodynamic characteristics of the steam-water.

6.3.3 Another major feature of the large capacity supercritical is titanium blades for last stage blades (LSBs); in fact, before the advent of Ti LSBs, large capacity machines were cross-compounded which entailed an independent alternator for LP stage turbines and is obviously expensive. Typical configuration of a 660 MW unit:

TABLE 1.7: TYPICAL CONFIGURATION OF A LARGE SIZED SUPERCRITICAL UNIT

Sl. No.	Subsystem/ Equipment	Description/ parameters
1	TURBINE BLOCK	
i)	Turbo generator configuration	HPT, Double flow IPT + 2 Nos Double flow LPT
ii)	No. of feed water heaters	7 (3 Nos LP; 3 Nos HP, one contact type)
iii)	Feed Pumps	3 Nos
iv)	Condensate Pumps	3 Nos
2	BOILER ISLAND	
i)	Firing	Tangential
ii)	No. of mills	6-10
iii)	Fans	2 x60 % (PA, FD and ID)

6.4 Typical performance parameters:

TABLE 1.8: TYPICAL PERFORMANCE PARAMETERS OF A LARGE SIZED SUPERCRITICAL UNIT

Sl. No.	Description	Value
1	Boiler efficiency %	
	Indian coal	87
	Imported coal	89
2	Turbine Cycle heat rate, kCal/ kWh	1830 – 1850 (@ 33^0C CW Temp)
3	Auxiliary power consumption	5.0-5.5%
4	Environmental performance	
	CO2	0.9 T/ MWh
	SO2	300 – 500 ppm
	NOx	200- 300 ppm
	SPM	50 mg/ Nm3
	Consumptive Water Requirements	2.2- 2.5 M^3/ MWh

6.5 Start –up time, ramp up rates and load response.

6.5.1 The supercritical boiler needs a start up system till the water-steam cycle establishes once-through flow; for this purpose, water-steam separator vessel(s) is used which, acting like a drum, recirculates the feed water with a circulating pump till the load reaches around 30% at which the main boiler feed pump is pressed into service. There are different start up modes depending on the application.

6.5.2 Start-up time duration

TABLE 1.9: TYPICAL START UP PERIODS FOR SUPERCRITICAL UNITS

Start up	Time (hours)
Cold	7 - 10
Warm	4 - 5
Hot	3 – 4
Ramp up rates (% load/ minute)	
30- 50	2- 3
50 – 90	4- 8
90- 100	3- 5

Note: start up time upper range is for lignite.

6.6 This aspect is dissected further later in this section.

6.7 Metallurgy and the supercritical technology:

6.7.1 It is a well-recognised fact that early units of the supercritical had low reliability owing to the hassles associated with the metallurgical related failures which, eventually, at that point of time had forced the plant owners to jettison the technology itself for almost 3 decades.

6.7.2 However, after the re-visit happened in the technology in early 1990's as an offshoot of the energy crisis, a lot of advances have taken place in the metallurgical area which is giving the current fleet of supercritical units their reliability.

6.7.3 A significant point is that the metallurgical requirements of supercritical steam cycle equipments are calibrated in line with progressive increase in temperature (and marginally to pressure). For the base level technology, 540/ 568 °C, there is virtually no change in the metallurgy between subcritical and supercritical; the only exception is for water wall tubes where in place of carbon steel in subcritical, supercritical furnace temperature dynamics calls for alloy steel.

6.7.4 However, selecting supercritical steam cycles with higher temperature cycles will require major shift in the metallurgy, not only in selection, but in fabrication (welding/ heat treatments etc.), as well. Conventionally, ferritic steel is the preferred choice for boiler applications in view of its superior thermal conductivity and moderate thermal expansion. These materials were limited by their creep resistance only.

6.7.5 However, materials research found two major material failure phenomena surfacing beyond 600 °C: Corrosion of the fire side and oxidation of the steam side for boiler tubes and ferritic materials area found to be not able to sustain these phenomena.

6.7.6 The alternatives are austenitic stainless steels or duplex steels; austenitic steels, while having excellent temperature resistance, can withstand both fire side corrosion and steam side oxidation, have inferior characteristics for application as heat transfer tubes inside boiler in view of lower thermal conductivity and higher expansion. Further, austenitic steels have inherently high nickel content making them expensive (even the bare material cost of Nickel is 30- 40 times of carbon steel). Further, since part of the superheater and reheater will be of ferritic steel, at transition areas, the changeover to austenite will call for dissimilar metal welds (DMW) which is a delicate process.

6.7.7 While the industry has been making progress in circumventing these challenges, there have been obvious regulatory and cost issues associated with material development. Since a good part of the world follows ASME boiler codes, some materials newly invented, especially those for temperature above 600 °C, take considerable time for acquiring approval in view of the tedious procedures and tests each material has to undergo. This obviously adds to the cost and sometimes even the schedule. In fact a case in point is about the 9% Chromium alloy steel from tubes and piping (T91/ P91). Though this material was introduced way back in 1990's (in the US), years later, evidence from premature weld failures had been reported from several installations pointing to issues with the basis of design standards for this material (Ref :*Prediction of creep crack growth properties of P91 parent and welded steel using remaining failure strain criteria Zhang, Nikbin 2009*). Today, this material, though the mainstay of virtually the entire fleet of large capacity subcritical and supercritical boiler tubes/steam piping, is handled with special guidelines developed by the industry and enforced at each stage right from cutting the material. Even as recently as last year, US EPRI has again analysed the influence of creep-fatigue interaction on the behaviour of P91 steel at 580 °C, keeping in view this material is used for steam service up to 596 °C.

6.7.8 Further, it has been found that certain materials developed recently (during the last decade) are being not recommended by certain utilities (e.g.: ASTM A 213 T23), though the exact reasons are not known.

6.7.9 As mentioned earlier, ferritic steel had been the mainstay of all subcritical units. While these materials are compatible with steam service for temperature up to 600 °C, when it comes to tubes inside the boiler, the metal temperature goes beyond 600 °C since these are exposed to high temperature flue gas. The metal temperature of the tubes could be about 50 °C above the steam temperature, which transcends the sustainable limit of ferritic tubes. While some amount of austenite cannot be avoided with steam temperatures up to 600 °C, beyond this level, the requirement of austenite increases more than proportionally and consequently causes the hassles associated with it. That is why in India, most of the 660 MW and even some 800 MW units stick to steam temperatures within 600 °C so as to reduce issues with metallurgy.

6.7.10 Even in India, most of the FOAK units for 660 MW use either 540/ 568 deg for SH and RH respectively, progressing to 568/ 596 only in subsequent phase.

6.8 Progressive improvements in Supercritical/Ultra-Supercritical technology:

6.8.1 General:

Though power plants with supercritical technology started in a major way more than a decade ago, improving the availability and reliability along with better efficiency took some time. A few of the improvements are as follows.

6.8.2 Combustion tuning and reduction of excess air :

Mitsubishi has made pioneering efforts in this and now it is understood to be implemented in their Indian projects. The approx. improvement in efficiency is 0.25 % (saving of ~ 17000 TPA of coal for a 1320 MW plant). However, it is not as straightforward as it appears to be since the excess air required in a boiler is fuel specific and if applied arbitrarily, (say for fuels with high fuel ratios), it has the potential to create the exact opposite consequences.

6.8.3 Limiting tube thickness in furnace area:

It has been found that since supercritical units nowadays operate with sliding pressure, it creates temperature stresses in the furnace tubes and hence attempt should be made to ensure that the tube thickness does not exceed beyond a threshold. This propels deployment of materials having improved creep strength.. (Ref*: Specification for 870 MW Boiler package for KEPCO, South Korea 2008*)

6.8.4 Furnace Tube design :

Development has been going on in furnace tube design. Of specific interest is B&W's patented combination design of multiple-lead ribbed (MLR) and optimised multiple-lead ribbed (OMLR) tubing. This was necessitated in view of the need for controlling the heat fluxes associated with sliding pressure operation.[4]

6.8.5 Dew point of sulphur dioxide:

This is another area of improvement carried out in design of boiler. Earlier, typically 15 to 20 °C margin was maintained between the dew point of flue gas and the boiler exit temperature in order to mitigate the cold end corrosion. It was found that for large capacity units and / high fuel cost situations, it makes significant economic sense to lower this margin for additional gain in boiler efficiency and consequent translation to improved plant operating cost. The current mark is about 8 to 10 °C. This may have some impact on the life of the air pre-heater last stages, but is expected to only partially offset the incremental gain in efficiency.[5]

6.8.6 Brush seals for turbines:

The leakage from an HP turbine can be as high as 1% of the throttle steam flow; migration to brush seals from the labyrinth type seals (hitherto employed) is expected to reduce the leakage of steam significantly and contribute to the turbine efficiency. Brush seals have been used in many overseas projects and it is understood that they are slowly gaining traction in Indian projects also.

6.8.7 Higher hydrogen pressure for alternator:

The pressure of the hydrogen used as coolant is found to have a direct impact on the efficiency of the generator. Currently large units use 5.2 bar (g) as the standard pressure for alternators.

6.8.8 Diagnostic measures:

A recent report suggests that corrosion monitoring and vibration monitoring technology developed by Japan's Fuji Electric is mainly aimed at low pressure turbine blades which have got a complex design in view of their extended length.[6]

6.9 Load response of Supercritical and subcritical units

6.9.1 Fundamentally, the response to load change of coal based units of thermal units with solid fuel is relatively low when compared to other technologies like gas turbines. This is because of the inertia associated with the pulverisation and consequent combustion.

6.9.2 Typically, it has been found that the OEMs inherently are conservative about the recommendation for start up and ramp up rates. One of the reasons for this is that the start up of the boiler turbine unit depends on a number of parameters across both boiler and turbine. However, for utilities, many times, sudden back-down of peer units makes it imperative to start up and ramp up the load faster.

6.9.3 Ramp up rates and response to load changes:

The ramp up rate normally specified for Indian thermal power plants is 3% per minute. It appears that this by and large corroborates the findings of various surveys and studies done about power plant dynamic behaviour in overseas plants also. In some cases, it may be possible to improve the ramp up rate to 5% per minute.

6.9.4 Load response – supercritical Vs subcritical: It is to be mentioned that there is a basic difference between normal load ramp capability during start up and response to a sudden change in the load during operation; this assumes significance in light of the need for priority generation when renewables achieve a critical mass in the generation basket.

6.9.5 From the documents available in the public domain, it appears that this subject has caught the attention of several researchers; however, a clear convergence of opinion appears to be lacking on this. In fact, one of the studies[7]was in connection with the UK grid which is highly demanding on the load response (ramp up/ back down of 10% load within 10- 30 seconds)

6.9.6 However, based on the available information, the following points have been brought out.

6.9.7 In supercritical units, unlike their subcritical peers, since there is no drum, there is no stored energy; hence when there is a sudden demand, it will call for two synchronised activities. On the one hand, the feed water control system has to exactly match the steam requirement demanded from the turbine; while the pulveriser has to momentarily produce the additional fuel to ensure the steam parameters. While feed water circuit can be designed with precision response, the pulveriser with its inherent sluggishness may not always be able to cope up.

6.9.8 Another study carried out on a 1000 MW Chinese supercritical unit mentions a back down from 980 MW to 800 MW at the rate of 20 MW per minute.[8]

6.9.9 Another study brought out that the instant rejection capability of the supercritical unit is around 30% and project that peak rejection capability is around 50%.[9]

6.9.10 One suggestion based on another study is that since the pulveriser happens to be the weakest link, an innovative control scheme to improve dynamic performance is to adjust the grinding pressure of the coal mill. The coal mill holds a certain volume of coal and power output can be increased by raising the hydraulic pressure of the mill to deliver coal faster to the boiler, increasing generation.[10]

6.9.11 Still another case reported from a US sub-critical unit shows plants retrofitted with simple sensors and automated responses improved plant ramp rates by 300%, though no further details are available.[10]

6.9.12 However, perhaps, these should not be taken as representative cases since the response of the integrated boiler-turbine group is a function of a number of variables including the control system design and can vary from plant to plant. It is also reported that in Europe, in view of the escalating proportion of renewables, the control systems of fossil plants are getting improved for faster to and fro switchover.

6.10 Capex and Opex of Subcritical and Supercritical units:

6.10.1 The prices available in public domain for some of the recent projects are tabulated below:

TABLE 1.10 : PROJECT COSTS OF RECENT COAL BASED POWER PROJECTS

Sl. No.	Project	Plant Size MW	Technology	Project cost Rs Million	Unit Cost Rs Million / MW
1	NTPC Barh	3 x 660	PF (Coal)	73400	56
2	Vallur Phase-II(NTPC/TNEB)	500	PF (Coal)	30870	62
3	NTPC Rihand Stage- III	2 x 500	PF (Coal)	62300	62
4	Raghunathpur (DVC)	2 x 600	PF (Coal)	6744	56
5	NLC Tuticorin	2 x 500	PF (Coal)	65400	65
6	Govindsahib (GVK, Punjab)	2 x 270	PF (Coal)	29630	55
7	Vandana Vidyut	2 x135	PF (Coal)	14580	54
8	RRUVNL , Chhabra	2x 660	PF(Coal)	56890	43(Only Contract Value for EPC)
9	OPGC Ib valley	2x660	PF(Coal)	56230	42.5(Aggregate BTG+BOP Contract value only)

6.10.2 From the table, it can be gauged that, though all prices may not be on the same platform (in respect of scope) there is no marked difference between the prices of supercritical and subcritical units.

6.10.3 One of the reasons is that the supercritical units currently being built in India are baseline technology units, i.e. at the lower levels of the pressure and temperature, and consequently have marginal cost impact.

6.10.4 Opex: The fixed part of the Opex for coal based stations has been capped by CERC for Cost plus regime stations till 2013- 2014. Beyond this period, they are mulling the methodology, have issued draft guidelines recently and have invited suggestions from stake–holders.

6.10.5 As for variable part, it will depend on the cost of fuel. While the cost of Indian coal is still on APM, it is not clear as to how the current overall deficit in coal requirement and consequentially imported coal forming part of the fuel mix for many stations will affect the variable cost.

6.11 Future of Supercritical units in India:

6.11.1 Though the first supercritical thermal unit was commissioned only in 2011, the technology appears to be fast maturing going by the trend in the market. As of now, the bulk of the thermal projects under construction, or recently commissioned, are of supercritical technology.

6.11.2 One of the main reasons for the escalating population of the supercritical units is the narrow price gaps with the subcritical technology. This coupled with overall better efficiency and lower atmospheric emission (on unit power generated) makes it the appropriate technology to adopt at current cost matrix of utility electricity in India.

6.12 Migration to Advanced Ultra-Supercritical technology- Current status:

6.12.1 Advanced USC plants refer to those operating at 300 bar/ 700 °C steam conditions or above. The need for development of this level of steam conditions was the fact that the incremental efficiency with the current fleet of supercritical/ USC plants with respect to the typical subcritical units are limited – about 4% or 2 % points.

6.12.2 However, steam conditions in the vicinity of 300- 350 bar and temperature 700- 750 °C are expected to take the plant efficiency to about 45-47 % on a gross basis. Besides, they are expected to bring down the CO2 emission to ~ 700 kg/ kWh.

6.12.3 Hence worldwide research was going on for development of advanced ultra-supercritical (A-USC) units which can give plant efficiencies 45% upwards which implies a value 10–12 % higher than even the supercritical units currently in service

6.12.4 Typical performance indicators of A-USC technology: The projected turbine cycle heat rates for the two steam–cycles adopted for A-USC technology are as follows:

TABLE 1.11: TYPICAL PERFORMANCE INDICATORS OF A-USC TECHNOLOGY

Sl. No.	Parameter	300 bar/ 700/ 720 °C	350 bar/ 735/ 760 °C
1	Turbine cycle HR	1650	1600
2	CO2 emission T/ MW	0.730	0.700

6.12.5 A brief look into the research work in the A-USC technology arena by overseas nations is presented below.

6.12.6 **European Programs**: In Europe, programs codenamed AD 700 and COMETES700 were aimed at 300 bar / 700/ 720 °C. As per the information available in the public domain[11]:

- For boilers, superalloys for superheater, reheater and headers were developed and tested.
- For turbines, welds of 10% Cr steels to superalloys have been produced and blades cast. Steam inlet valve casing has already been tested.
- There was plan to start a demonstration plant at Wilhemshaven for 50% efficiency (on LHV); the project reportedly got stalled in 2010 owing to cost projections; now reportedly it is to be completed by 2021.

6.12.7 **US programme**: The research program in the US has been launched aiming for thermal power technology with steam temperatures in the 750 °C region, as against the 700 °C goal set by EU program[12,13].Further, they have also taken into consideration the domestic coal chemistry with higher sulphur content and its possible implications at higher temperatures. The following have been the highlights/ updates of US program:

- After preliminary evaluation, five superalloys were selected for further testing.
- Demonstration tests of these alloys in simulated environments have reportedly shown encouraging results. Successfully welding up to 75 mm thickness has been achieved.

- As per the latest update available in public domain, Inconel 740 has been found to have the best creep strength and has obtained ASME code approval last year.
- A 600 MW demonstration plant is scheduled by 2021.

Some of the findings reported from the US research are:

1.0 Beyond 650 °C, corrosion increases significantly up to 690 °C and then drops down. 2.0 Peak metal loss for low alloy ferritic steel is about 50 % more than those for stainless steel. 3.0 Steam-side oxidation rates and weight loss were lower for materials with chromium content of more than 12% with ferritic steels and 19% chromium for iron-based austenitic materials. 4.0 Surface cold work treatment of non-nickel-based materials used above 700C does not produce effective results.

6.12.8 **Japanese program**: Codenamed METI Cool earth, Japanese quest for high efficiency thermal plants commenced in 2008. The highlights and updates of the Japan program are as follows:

- Tests for Material properties like temperature compatibility, weldability along with tensile strength have been progressing.
- Super alloy piping of various sizes has been fabricated.
- Turbine rotors castings and valves have been forged and have been undergoing testing.
- All test results have reportedly been in line with the simulations.
- Boiler and turbine pilot tests are planned for 2015- 2016 and commercial operations are targeted by 2020.

6.12.9 Chinese program: China came fairly late into the research- in July 2011 with a national program titled '*700℃ Innovative Alliance*'[14] under a tripartite collaborative programme involving academia, manufacturing industry and utilities. The biggest advantage with China is the largest fleet of 1000 MW USC plants in the world- numbering around 60 in 2012.

6.13 Barriers in migrating to A-USC technology in India:

6.13.1 While the advantage A-USC plants are well-known, adoption of these into Indian thermal power sector has a lot of barriers, technological as well as economic.

Since fuel has a major influence in the design and consequently cost of the boiler, an attempt has also been going on to model the boiler for Indian coal characteristics. Several studies list multiple challenges with Indian coal like very high ash (ash loading per MW about 7 – 10 times as compared to typical overseas coal), presence of alpha quartz with severe erosion characteristics in some coal mines, etc. These characteristics call for substantial reduction in flue gas velocity across the boiler and consequently, significant increase in the size of the boiler apart from the need for larger pulverisers and other auxiliaries.[15]

6.13.2 The same study however points out a positive feature of Indian coal, that the sulphur content is low and hence fireside corrosion, (mostly due to sulphates), potentially could be low. However, now even this point loses its relevance since India has been importing 15 – 20 % of its thermal coal requirement and going by the projections given by various policy documents, in case the lull in the current GDP growth lifts, a significant amount of coal (200 MT plus) may have to be imported, which means a good number of thermal fleets will be using blended coal with sulphur of median content, almost double that of typical Indian coal.

6.13.3 However, by far the single greatest challenge will be metallurgical advancement.

The Current status of A-USC development in India and likely trajectory in the immediate future are discussed below.

6.13.4 At the outset, though some advancement has reportedly been made in India's effort to master the technology, (like development of two Superalloys by NFC and IGCAR and submission of design memorandum by BHEL to PSA, GoI etc); the road towards development and demonstration appears to be fairly distant. From the available information, the schedule originally set for the demonstration plant is 2018, which appears a challenge at this stage. (*The Hindu, Apr 20, 2013*)

6.13.5 The significant delay and cancellation midway of the demonstration project of some European projects are also pointers to the challenges on this front.

IEA has gone on record that commercialisation of A-USC will not be feasible before 2025[16]

6.13.6 Another example in our own stable is the 180 MW IGCC demonstration project that commenced with a lot of expectations in 2008. Five years down the line, reportedly, there has not been much progress on this, for whatever reasons.

6.13.7 However, equally important is the uncertainty in the cost. A-USC steam cycle is going to use substantial amounts of nickel based alloys. The following information is worth noting in this connection:

- During the initial phase of research in the US, 2 out of the 6 candidate materials tested were found to be not suitable and hence removed from further consideration [13]
- Further, some of the recent research papers, report issues with some materials like chromium evaporation at elevated temperature[17]. These are just pointers to the probable 'minefields' on the road to development of high technology equipment.

6.13.8 Overall, the current cost-economics in general and our inherent price-sensitive electricity market do not appear to favour adoption of A-USC technology in the near term.

6.13.9 Some externalities on this are discussed separately later in this paper.

6.14 Projection of load response behaviour:

6.14.1 Since no plants are currently operating, it is not possible to postulate the load behaviour; however, basically, since these plants will have a significant fixed cost associated with investment and O&M, economics dictate that they be only operated as base load plants in order to leverage their enhanced efficiency in a sustained manner.

6.14.2 Further, initial results on metallurgical behaviour shows that since critical components forming boiler and turbine will have high thickness, it will be necessary to have minimum ramp up and slow load response on these units in order to mitigate thermal distortion, at least till such time as the technology becomes ‘handy’.

6.15 Cost-economics in Indian conditions:

6.15.1 As discussed initially, from the standpoint of boiler design, if an A-USC boiler has to be designed for firing solely Indian domestically mine coal, it will require a substantially bigger size and will obviously compound the cost of the technology.

6.15.2 Further, at the current level of cost projections, A-USC plants will have to be modelled along the lines of UMPPs; besides, since the FOAK units are yet to be demonstrated even in advanced countries, if the development is to be indigenised, it has to have some scale to justify the cost.

6.15.3 Apart from this, a wide angle projection of cost to benefits show that the A-USC plants' will render an economic advantage only with large stations, (4- 5 GW), firing imported coal at the prevailing cost levels which implies that plants should be built close to coastal areas. However, this can invite fuel risks associated with imported coal since the prices cannot be regulated. The other alternative is to use washed coal.

6.15.4 Presuming that the demonstration of this technology will be available after 2020, the order-of – magnitude cost projections for a 4000 MW unit, operating at 300 bar/ 700°C are presented below(At 2013 cost level)

TABLE 1.12: PROJECTED COST RANGE OF A-USC UNITS

Sl No.	Cost head	Cost Rs Million	
		Optimistic	Pessimistic
1.0	BTG Island	240 000	300 000
2.0	BOP	40 000	55 000
3.0	Total Cost at start of operation	330 000	420 000

6.15.5 Basis: In the optimistic scenario, the prices of superalloys are expected to vary in a close range; further, in case of BOP, the prices will come down on two counts: one is the reduction in chain size and the other is the economies of scale for 4000 MW size.

7.0 FLUIDIZED BED COMBUSTION.

7.1 Basic description: In Fluidised bed combustion (FBC) boiler, the combustion of the coal particles takes place in a suspended condition at a temperature below the ash melting point, typically between 850 and 900 °C.

Primarily there are 3 types of FBC processes:

- Pressurised Fluidized bed combustion (PFBC)
- Bubbling fluidized bed Combustion (BFBC)
- Circulating Fluidized bed combustion (CFBC)

Of these, BFBC and CFBC employ combustion at atmospheric pressure whereas in PFBC, the combustion takes place at elevated pressures.

7.2 Common attributes of FBC technology:

The primary differentiating features of FBC from PF boilers are tabulated below:

TABLE 1.13: COMPARISON – PF Vs FBC

Sl. No.	Attribute	PF	FBC	REMARKS
1	Fuel Size	Pulverised powder	8- 10 mm for lignite 6- 8 for sub-bituminous coal ~ 6 mm for anthracite	
2	Fuel diversity	Moderate	High	
3	Fuel flexibility	Moderate	High	FBC can accept higher burden (ash+moisture) in fuel. This attribute facilitates firing low calorific value fuels like washery middling.
4	Sulphur capture	Need expensive post- combustion treatment	Can be captured in bed injecting sorbent.	Both these become deciding factors for firing high sulphur fuels like lignite/ petcoke.
5	NOx generation	High	Negligible since combustion takes place at moderate temperatures	
6	Size	Upto 1200 MW proven	Largest size made is 460 MW	1. 800 MW supercritical CFB under development. 2. A 600 MW unit has reportedly already been commissioned in China; however, no further details are known[18].
7	Efficiency	85- 89	85- 89	In some designs, Efficiency of CFBC units could be marginally lower and auxiliary power is marginally higher.
8	Hot start up time	2 hours	Down to 30 minutes	
9	Low load operation	Oil support required	Not required	

7.3 The unique feature of the FBC technology is that it can accept fuels on both extremes of the heating value – from low volatile high GCV anthracite to low GCV high ash / moisture Residual derived fuels-which PF technology cannot handle with stable behaviour.

7.4 In the context, it is pertinent to note that coal washing generates a lot of rejects with low calorific value (1500- 3000 kCal/ kg). Conservatively, 10% is the reject from coal washing and on a 100 MTPA washery capacity; the reject works out to 10 MTPA. This is equivalent to the requirement of about 1500- 1800 MW power.

7.5 Keeping in view the special characteristics of the rejects (upto 70 % ash), these can be effectively utilised only by firing in an FBC boiler.

7.6 Pressurised Fluidised bed combustion (PFBC).

7.6.1 The PFBC design was conceptualised originally as the core of a possible combined cycle high efficiency power generating system.

7.6.2 This technology was attractive for combined cycle application earlier when the firing temperature in gas turbines was low; those coupled with good environment friendliness have made economic sense.

7.6.3 However, with the advancements in gas turbine technology, as the firing temperature of the gas turbine moved up, the PFBC system started losing its core advantage.

7.6.4 The other reason which compounded the decline in the interest in the technology is lack of healthy market competition.

7.6.5 There is no report of any PBFC system of large capacity being built for power generation application in recent times.

7.7 Bubbling Bed Fluidised Combustion (BFBC):

7.7.1 This is the least expensive form of FBC technology and is primarily used for low capacities. The efficiencies are relatively low in view of higher carbon carry over through flue gas. It is typically used for captive applications or where fuel costs are low.

7.8 Circulating Fluidised bed combustion (CFBC):

7.8.1 By far this is the most prominent technology amongst the three FBC variations.

7.8.2 Major components of a typical CFBC boiler are :

- Combustor where primary air enters from the bottom in order to keep the fuel, sorbent and inert particles in suspended form.
- Secondary air is supplied at various levels for completion of combustion.
- Particulate separator.

7.8.3 Their primary attributes are the scale coupled with comparable efficiency along with their environmental friendliness. CFBC units are operationally matured from 30 MW to 460 MW and are the chosen technology where fuel has high sulphur content.

7.9 Design variations: Within the CFBC technology space, the main variation across established designs is the method of particulate capture.

7.10 Primarily there are three designs available on this:

7.10.1 Hot/ Cold Cyclone design: In this, the flue gases from the combustor enter a cyclone and due to cyclonic action, the combustibles return to the furnace at the bottom and are re-circulated with the incoming fuel. The flue gas from the cyclone goes to the second pass of the boiler and subsequently to the air heater, on the way to the stack through a particulate filter.

In this design, again, there are two variations: Hot and cold cyclone designs

i) In hot cyclone design (typical vendors: LENTJES/ Alstom/Foster Wheeler) the flue gases enter the cyclone at a fairly high temperature since the combustor water walls would be absorbing only a part of the heat generated.

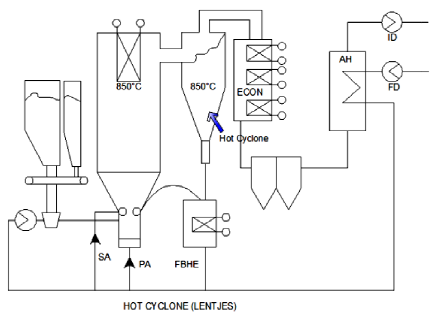


FIG 1.1 : HOT CYCLONE DESIGN CFBC SCHEMATIC

Hot cyclone design is characterised by high turbulence and consequently excellent combustion and sulphur removal efficiency.
The main draw-back of classical hot cyclone design is a significantly thick refractory for cyclone and return seal pot area (~ 500 mm) which makes it vulnerable for failure.
Part of this drawback has been overcome in the compact design technology developed by Foster wheeler. The variation is in the cyclone where the refractory lining has been replaced by a water-cooled membrane panel; however, this has reportedly resulted in some cannibalisation of efficiency.

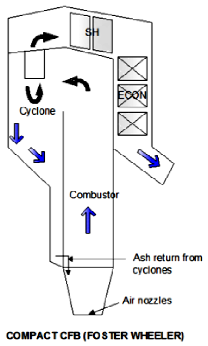


FIG 1.2 COMPACT CFBC SCHEMATIC

ii) In the cold cyclone design, typically the entire superheater and part of the economiser tubes are located in the combustor. Hence the flue gas enters the cyclone at a much lower temperature obviating about 80% of the refractory. This improves the cold start up time significantly. The design is further characterised by wider combustor bed and lower fluidisation velocities and consequently lower aux power consumption.

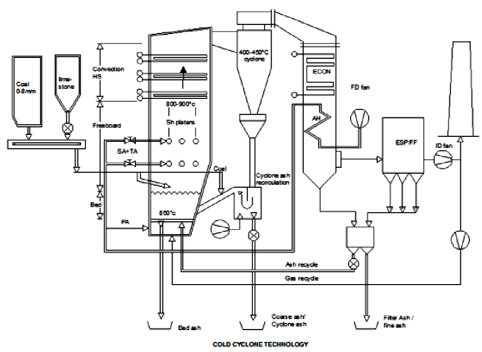


FIG 1.3 COLD CYCLONE CFBC SCHEMATIC

7.10.2 U- Beam Solid particulate filter :
i) Originally developed by Studsvik of Sweden, this design is now used by Babcock & Wilcox. The basic attribute of the design is the use of U-shaped beams for primary filtration of particles. The elimination of the cyclone implies a massive reduction in the refractory and in turn a much faster cold start up time.

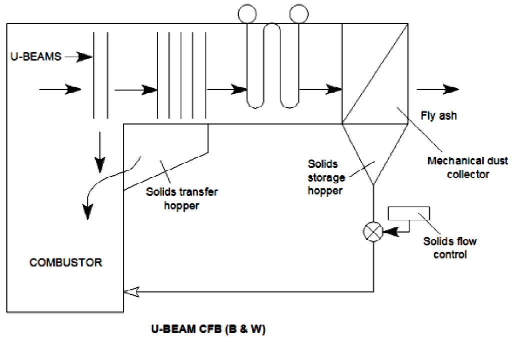


FIG 1.4: U BEAM PARTICULATE SEPARATOR CBFC DESIGN SCHEMATIC

ii) The U-beam typically captures about 95 - 97% of the particulate matter and the rest is captured by the mechanical dust collector located upstream of the economiser.
U-Beam design is characterised by low bed velocity and consequently low fan power; however, chances of temperature excursions are more likely in view of lower turbulence; this can give rise to overheating of U beams and consequent loss in collection efficiency.
However, since refractory requirement is only one-tenth of the hot cyclone design, the start-up of the unit is faster.

7.11 **Performance:**

Efficiency and Auxiliary power:

7.11.1 The data available from the Lagisza 460 MW plant which happens to be the largest CFBC boiler shows the following values of efficiency of boiler and plant aux power:
Boiler efficiency: The efficiency of CFB boiler for coal based large size plants reported from overseas installations is in the range of 89 to 91% in most cases. In the 460 MW supercritical plants at Lagisza, the value reported by the OEM is 94.83 (LHV) which may be about 91% on HHV. However, it needs to be noted that there is a heat recovery system in the flue gas downstream of ESP and the flue gas is exiting to stack at 85 °C[19]. However, another recent article[91] has projected lower efficiency for CFBC units on account of the need to burn larger fuel size.

7.11.2 In respect of auxiliary power, there are some variations between different designs with the hot cyclone design taking marginally higher power in view of often higher inert to fuel ratio in the combustor.
The figure reported from Lagisza is about 4.5 %, which is comparable with PC fired plants from overseas without FGD/ NOx systems. In India, typically the aux power will be about 1% more in view of high ash coal.

7.12 **Sensitivity to fuel on physical size:**

Though CFBC boilers can accept all types of fuels, it is still sensitive to the fuel ratio E.g. for a 1000 TPH boiler (~ 300 MWe)

- Lignite fired boiler will have a height of around 45- 50 m,
  While,
- An anthracite boiler will need a height of 50 to 55 m for identical combustion efficiency.[20]

7.13 Response to grid :

7.13.1 Response to grid of CFBC is reportedly comparable to a PC fired boiler. A 234MWTh (~ 70 MWe) boiler in Poland reportedly has given 7% load change per minute. However, this is a far smaller boiler.

7.13.2 The load ramp rate reported by the OEM for the Lagisza 460 MW boiler is 4% per minute; however, an independent report says 2% per minute. It is possible that the upper range is achievable for loads close to the rated load while average loadings could be lower in the 2% range.

7.14 Overseas experience:

7.14.1 Thousands of CFB units have been installed across the globe. The major countries with large sized units are China, Poland, Germany and US. However, most of the units till recently are of mid-size for less than 300 MW capacities. Of late, however, significant strides have been made in scaling up. The following developments have led to this.

7.14.2 Air pollutions norms have been getting tightened across advanced economies with high per capita energy consumption.

7.14.3 In many cases, cost of CFBC technology with sorbent injection was found to be comparable to PF boilers with FGD and de-nitrification system.

7.14.4 Decrease in the quality of coal in respect of sulphur, ash and moisture contents have also contributed to migration to CFBC boilers.

> China's Dongfang has claimed they have commissioned the largest CBF boiler in the world (600 MW) by March 2013; however, no further information is available in the public domain on this.[18]

7.14.5 The Foster Wheeler's 460 MW boiler, which is the first supercritical boiler in the world, has been operating at Lagisza in Poland since 2009. The salient parameters for this boiler is are as follows:

TABLE 1.14: SALIENT FEATURES OF 460 MW SUPERCRITICAL CFBC BOILER

Parameter	Steam Flow	Main Steam pressure at turbine inlet	Main Steam temperature at turbine inlet	HRH Steam temperature at turbine inlet	SOx	NOx	SPM
Value	361 kg/ s	27.5 MPa	560 °C	580 °C	< 30 mg/ Nm3	< 200 mg/ Nm3	< 200 mg/ Nm3

7.14.6 Based on the information available, major projects involving supercritical CFB boiler under execution/ planning are tabulated below:

TABLE 1.15: MAJOR CFBC BASED PROJECTS UNDER EXECUTION

	Location, Country	Plant Capacity	Boiler parameters	Fuel	Emission target	Remarks
1	Samcheok, Korea	550 MW x 4 Nos (first phase)	272 bar/ 602°C / 602°C	Bituminous coal (can fire 20 % biomass) Moisture ; 20-43%	NOx <50 ppmvd with SCR; SOx < 100 ppm	Construction commenced.
2	Novocherkassk, Russia,	330 MW	244 bar/ 565°C	Anthracite/ Bituminous coal	NA	

7.15 Recent advances in technology:

7.15.1 While component improvement has been an on-going process, one of the significant developments in CFBC technology arena in recent times has been diversification into oxy-fuel combustion which can improve carbon capture. As per IEA Clean Coal Centre, though pilot studies have been going on in global academia on this, Foster Wheeler has taken a step forward by using a new technology called Flexi-Burn CFB, and a pilot scale 30 MWTh unit has already been commissioned in 2011. Based on the results of various tests on this pilot plant, a demonstration unit of 300 MWe is being developed and is scheduled for commissioning in 2015 towards commercialisation of this technology[21].

7.16 Indian Scenarios:

7.16.1 In India, experience with large scale CFBC boilers is limited. The largest size CFBC boiler installed in India as on date is at NLC near Salem ; designed in collaboration with LENTJES the first unit of 250 MW, the project had got delayed by more than two years; further, it has reportedly undergone major problems after commissioning, which eventually led to re-engineering.[22,23]

7.16.2 Similar is the case with a mid-size boiler at GMDC in Gujarat. Though it was commissioned in 2007, the operations were affected by sustained problems in critical areas; the plant owner has recently outsourced the operation of the plant to an overseas entity. [24]

7.16.3 The major problems reported from both these plants are tabulated below:

TABLE 1.16: MAJOR FAILURES IN CFBC PROJECTS IN INDIA

	2X 250 MW CFBC Boiler at NLC Neyveli	2 x 125 MW boiler at GMDC Akrimota
SL. No.	Areas of failure	
1	Commissioning : 2012	Commissioning: 2007
2	Steam Cooled wall screen failure	Loopseal bellow : 21 failures in one year
3	Fluid bed heat exchanger coil and refractory failure	SH and RH panels leakage (though material used is ASTM A 213 T91)
4	Support system failure	Overall, could not sustain operation.

7.16.4 The Neyveli 250 MW unit has reportedly taken more than a year for the unit to return to operation.

7.16.5 There are other smaller size CFBC boilers in India and one common issue reported from different installations is a failure of refractory, for unknown reasons.

7.17 Barriers for adoption.

7.17.1 The major barrier hitherto against adoption of CFBC technology in India in large scale is discussed below.

7.17.2 Lack of operational experience with large units even in overseas countries: Till last decade, in many overseas countries, CFBC units were limited to mid –size (most of them in 100 – 200 MW range, with a few units in the vicinity of 300 MW). They were mainly meant for firing low calorific value fuels. Only during the last 5 years or so has a major scaling up effort taken place in the CFBC space.

7.17.3 No indigenous technology: Unlike PF, where the technology is by and large locally available, no Indian OEM owns the core technology.

7.17.4 Though the technology community in India is aware of the environmental benefits of adopting CFBC, since the environmental compliance in India has been considered a 'low hanging fruit' (at least till recently), there was no focussed effort to harness and develop this technology.

7.17.5 Three overseas OEMs viz.Foster Wheeler, Alstom and Babcock & Wilcox together control the lion's share of the global market with its attendant impact on price.

7.17.6 Short-medium term market condition: From the information available from across the globe, it has been found that at this point of time, several large scale CFBC based projects are being planned in many countries. This may make the market favourable to technology suppliers/ equipment manufacturers (seller's market in trade parlance), with prospective increase in the cost of CFBC based plants at least in the short term.

7.18 Capex and Opex.

7.18.1 Basis: Since only a few medium scale CFBC units have been installed in India as of now, the cost of building or operating large scale CFBC boilers in India cannot be forecast with a fair degree of certainty.

7.18.2 Following are the project cost of CFBC projects available in the public domain:

TABLE 1.17: CFBC BASED POWER PROJECT COSTS

Sl. No.	Project	Plant Size MW	Technology	Project cost Rs Million	Unit cost Rs Million / MW
1	NLC, Barsinghpur, Raj	2 x125	Lignite	16000	64 *
2	NLC Neyveli	2 x 250	Lignite	30270	60.5 **

Source : CEA.

*There has been representation from developer to CERC for sanction of significantly increased cost.

**The project had commenced sometime in 2006.

7.18.3 It has been found that the median EPC cost of large sized projects during the past 2 years has been around Rs 45 million/ MW and the cost of the power block, (consisting of Boiler-turbine generator), is around Rs 25 Million/ MW.

7.18.4 Of the cost of BTG, typically 60% cost can be apportioned to Boiler Island.

7.18.5 Thus, for large projects, estimated costs for boiler island are as follows :

Rs 15 - 18 million / MW for coal

Rs 20 - 25 million MW for lignite

7.18.6 Opex: As per CERC notification issued for the control period 2009-2014, for sizes beyond 125 MW, no additional O&M cost has been consented for lignite fired CFBC units for those stations that are under cost plus regime.

7.19 Forecast of CFB technology for Indian thermal generation:

7.19.1 In the short term, CFB technology will most likely be used for lignite application in view of lack of operational experience with large size units even overseas.

7.19.2 One of the compelling reasons that CFBC technology developed from mid-size units into the core of full-fledged utility power plants was its inherent ability for reduced NOx and SOx emission without adopting any end-of-pipe methods.

7.19.3 In India, as of now, there are no emission limits on both NOx and SOx and hence unless there are caps on these emissions comparable to levels in overseas countries, CFB may not be adopted for large scale utility plants firing coal.

7.19.4 In case of lignite, migration to CFB has happened in view of the particular characteristics of the fuel which is not the case with coal.

7.20 Supercritical CFBC for Indian conditions:

7.20.1 In India, CFBC technology for utility power has just been ushered in by way of two mid –size (250 MW) subcritical units. The performance of these units has not been encouraging with failures on multiple fronts and consequently calling for even re-engineering.

7.20.2 Supercritical technology for Indian thermal power cost economics warrants a minimum size of in the region of 600 MW.

7.20.3 As of now, CFBC units of 600 MW has only been installed in China, for which no further details such as fuel quality or steam conditions are known.

7.20.4 Further, globally, supercritical CFBC boiler units are manufactured by a handful of OEMs and hence, at least in the formative phase, the cost-economics of these units in India may be found attractive only with increased cost of fuels. Since as of now, only lignite based pit head stations- with relatively lower cost of fuel – are only even using subcritical CFBC units, adoption of CFBC for supercritical applications may take a while.

7.20.5 Ramp rates of supercritical CFBC units are projected to be in close range with that of PF units. However, globally, since supercritical CFBC units are yet to mature operationally, initial units may have lower ramp rates when compared to their PF peers.

Section II

Emerging Coal/ Lignite Based Generation Technologies

1.0 INTRODUCTION

1.1 This section discusses the technologies that have emerged during the past decade for large sized power plant application and their integration with Carbon Capture.

1.2 These are:

- Integrated gasification and combined cycle (IGCC)
- Underground Coal Gasification.

1.3 Along with these, the carbon capture and storage, specifically its integration with power projects, are also covered.

2.0 INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

2.1 Process Description:

2.1.1 Gasification is the process in which fuels undergo partial combustion i.e. at air fuel ratios significantly lower than actual combustion. The product of gasification is called syngas.

2.1.2 Though the ratio of oxygen to coal in gasification is about one-fourth that of combustion, in practice, for ensuring complete gasification, oxygen will be marginally rich.

2.1.3 Transcending the qualitative difference between the processes, there are fundamental variances between both combustion and gasification as follows.

TABLE 2.1: COMPARISON BETWEEN COMBUSTION AND GASIFICATION

	CONSTITUENT / ENTITY	COMBUSTION	GASIFICATION	REMARKS
1	Operating pressure	Atmospheric	High pressure	
2	Feed gas	Air	Steam / oxygen	
3	Oxidiser	Excess air (oxidising)	Sub-stoichiometric(Reducing)	
4	Products	CO2, H2O	CO, H2, CH4, CO2, H2O	
5	Fuel N_2	Becomes NO_x	Gets converted into NH_3 or HCN	Both NH_3 and HCN can be cleaned up and hence syngas can be made virtually devoid of NO_x
6	Sulphur	Becomes SO_x	Gets converted into H_2S and COS	95 – 99 %SO_x can be removed.
7	Heat energy	Captured by waterwall tubes	Retained	Adequate refractory used to ensure minimum heat loss in order to ensure maximum heat energy in the syngas.
8	Ash condition	Mostly dry	Mostly slagging	
9	Tar production	Nil	Normal	

Note: The properties shown are generic; individual cases can have variations.

2.2 Gasification Technologies:

2.2.1 Following are the primary technologies developed by different OEMs across the globe and their primary attributes:

TABLE 2.2: GASIFIER TYPES AND ATTRIBUTES

Parameter	Entrained Flow	Fluidised Bed	Fixed Bed
Coal	Pulverised For slurry feed low moisture or hydrophobic coals preferred.	Crushed (0.5 to 5mm). Mixed with a bed material to aid heat transfer and to capture S species	Lump(5 to 80 mm) Optimal PSD to maintain bed integrity. Strong requirements of coal caking and agglomerating behaviour.
O2 to coal ratio	0.3- 1.2	0.25 – 1.0	0.12- 0.8
Fuel flexibility	Wide; High reactivity coals maybe cheaper to run; most fuels can be accommodated with appropriate knowledge.	Lower operating temperature volatile coals, such as sub bit and lignite, are favoured.	Limitation on coal reactivity.
Temp Range, °C	1250- 1600	900- 1000	400- 700
Ash Content	Refractory systems less ash is better. Possible issues with slag corrosion/erosion. Non refractory systems have a minimum ash requirement to protect wall. However, very high ash can be a hassle for sustained operation.	High AFT required to prevent ash melting or sticking.	Dry bottom gasifiers have similar requirements of fluidized bed gasifiers. Low ash content preferred; dry bottom can accommodate high ash.
Pressure	High pressure(30- 80)	10- 30	Low (1- 10)
Slag	Slag flow with 25 Pa s or less at tapping temperature. Tcv less than operating temperature.	Ash softening and/or melting is not desirable. Prone to contain more oil and tars in Syngas.	For slagging operation requirements are similar to entrained flow gasification for dry bottom operation requirements are similar to fluidised bed.
Product gas	More CO+H2; less methane	Mid-way between entrained and fixed bed type	More methane and less CO+ H2
Efficiency	High	Moderate	Low

2.2.2 Fixed bed gasifiers are sensitive to fuel properties and low throughput which makes them suitable for chemical industry applications.

2.2.3 Fluidised bed gasifiers are also sensitive to fuel reactivity and thus are suitable for biomass and lignite applications of small to medium size. One of the known IGCC applications where FBC gasifiers were deployed was for a 100 MW plant in the US, where the reliability of gas cleaning and overall and integration was an issue. Available literature does not show any large scale IGCC with FBC gasifiers.[25]

2.2.4 Since entrained flow type can accommodate coals with diverse characteristics for large size applications, this has become the frontline technology nowadays.

2.2.5 However, recently a hybrid technology called transport gasifier has been developed by KBR and is being constructed at Kemper County's IGCC. The transport gasifier combines the characteristics of both entrained flow and fluid bed gasifiers.[26]

2.3 Entrained flow gasifiers: Primary common attributes and variants across OEMs:

2.3.1 In an entrained gasifier, pulverised coal is fed either in dry form or in the form of slurry along with air or oxygen, and is converted into syngas at an operating temperature of ~ 1500 °C. The ash present is removed as molten slag. The operating temperature ensures minimum generation of methane and tar while promoting high carbon conversion rates.

2.3.2 Following are the established technology suppliers based on entrained flow concept.

GE Energy	Shell	CB&I (Conoco-Philips E-Gas)	Mitsubishi Heavy Industries	Siemens

2.3.3 The primary features of the entrained flow gasifiers are tabulated below:

TABLE 2.3: ENTRAINED FLOW GASIFIERS

Sl. No.	Technology	No. of stages	Oxidant	Feed	Configuration	Gasifier wall
1	Shell	1	O2	Dry	Up flow	Waterwall
2	GE	1	O2	Slurry	Down flow	Refractory
3	CB&I (Conco Philips)	2	O2	Slurry	Up flow	Refractory
4	MHI	2	Air	Dry	Up flow	Refractory &Waterwall
5	SIEMENS	1	O2	Dry	Down flow	Waterwall

2.3.4 Some basic technical description of these technologies are given below:

2.3.5 GE Energy:

Originally developed by TEXACO (acquired by GE Energy about 10 years ago), the primary feature of the gasifier are: slurry feeding and oxygen based single stage gasification. Slag and syngas exit the bottom of the gasifier. GE is currently building two gasifiers in China which rank amongst the largest in the world.

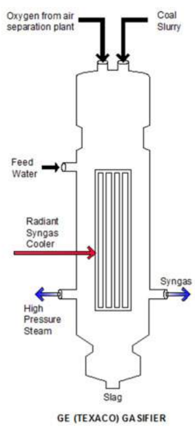


FIG 2.1 GE GASIFIER

2.3.6 CB&I

Originally developed by Conoco- Philips, the E-Gas technology is a two stage, oxygen blown, slurry-fed up-flow gasifier. It was developed by Dow in the late 1970s for sub-bituminous coals, and has successfully gasified bituminous coals and petroleum coke. The E-gas technology is used at the Wabash River commercial 262 MWe IGCC power plant where it has been operational since 1995

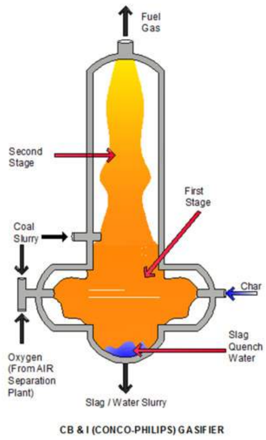


FIG 2.2 CB&I GASIFIER

2.3.7 SIEMENS

Originally designed for gasification of lignites and waste materials, this technology has passed through two ownerships before being acquired by SIEMENS in 2006. The gasifier is oxygen-blown down-flow dry-feed, with gasification occurring in a water-wall-lined vessel and the syngas partially-quenched. The product gas and slag exit the gasifier through the same outlet, as shown in the figure.

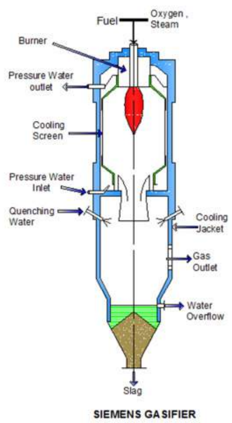


FIG 2.3 SIEMENS GASIFIER

2.3.8 Shell

The gasifier developed by Shell consists of a single stage, oxygen-blown, dry-feed up-flow gasifier, with a water-cooled membrane wall. The syngas produced in the SCGP gasifier is traditionally partially-quenched using cold recycle gas (to 900°C).

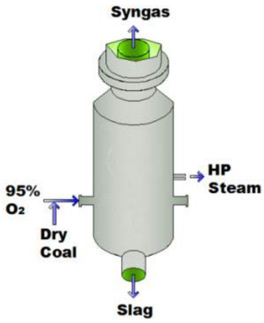


FIG 2.4 SHELL GASIFIER

2.3.9 Mitsubishi Heavy Industries
The primary difference between the entrained gasifiers described above and the MHI design is that the latter is air-blown type. The other features are that it is a two stage, upflow design.

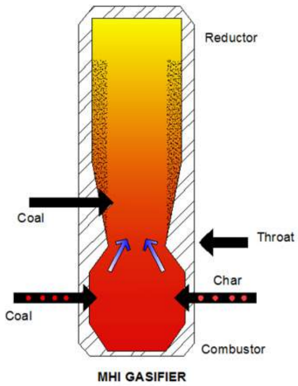


FIG 2.5 MHI GASIFIER

2.4 Gasifier technologies recently developed under demonstration.

2.4.1 Apart from the technologies established over the years and operating across the globe, two recent technologies have been making their way into the IGCC space:

One is the Transport gasifier. This is a hybrid design developed by Southern Co., an Atlanta-based electric utility company, and KBR Inc. (formerly Kellogg Brown and Root LLC), along with other partners, including the U.S. Department of Energy.

The other is a technology developed by Huaneng Clean Energy Research Institute (HCERI), formerly Thermal Power Research Institute (TPRI). According to US DOE, HCERI has developed and patented gasification technology that is being used in numerous gasification facilities throughout China. The technology has been reportedly developed and refined for over 16 years.[27]

2.4.2 **Transport gasifier**: (Southern Co KBR, USA)
The design tries to combine the high efficiency of the entrained type gasifiers with the better environmental performance of the fluidised bed design.

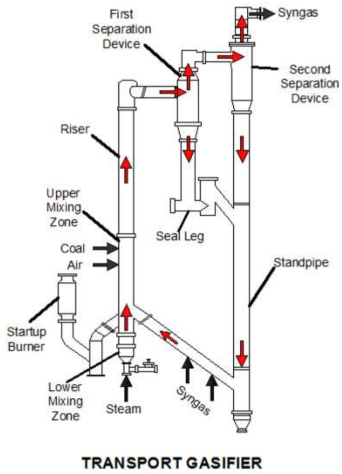


FIG 2.6 TRANSPORT GASIFIER

The technology is adopted from KBR's catalytic cracker technology primarily developed for petroleum refinery applications. The main feature of the design is higher circulation rates, fluid velocities, and riser densities in relation to a conventional circulating fluidized bed which produces higher throughput, better mixing, and higher mass and heat transfer rates. The primary advantage of the TRIG gasifier is that since it uses a dry feed and does not melt the ash in the feedstock, it is fairly compatible with fuels such as sub-bituminous coal, lignite or other fuels with high ash or moisture content. The developer claims it can economically handle coals with up to 50% ash(*Ref: www.greeningfoil.com, 2010*).
TRIG operates at moderate temperatures and below the melting point of ash. Thisreportedly provides more reliable operation, while using less oxidant and energy. In particular, the KBR gasifier's proprietary ash removal systemreportedly eliminates the technical difficulties associated with slag handling faced by conventional slagging gasifiers. Unlike other commercial gasifiers, which operate at much higher severity and therefore require costly spare equipment, or maintaining of multiple gasifiers (trains) for requisite availability, the TRIG design reportedly requires no spares.

2.4.3 HCERI Gasifier

According to US DOE, HCERI gasification technology is a two-stage dry-feed, water-cooled gasifier. The first stage of the gasifier reacts 80 to 85% of the coal feed with pure oxygen and steam. The steam and the remaining 15 to 20% of the feed coal are fed into the second stage, which operates at about 1400 to 1500°C. The temperature of the outlet syngas is decreased to 900°C due to the second stage's endothermic reaction - helping the slag particles to solidify, as well as improving the gasifier's thermal efficiency.

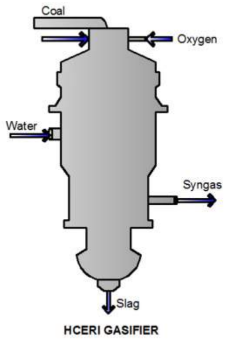


FIG 2.7 HCERI GASIFIER

The gasification technology can also be applied to other feedstocks, such as petcoke, and low quality coals with high sulphur content. Commercially available sulphur capture equipment can effectively remove up to 99.9% of the sulphur from a gasification gas stream, ensuring the plant's environmental compliance.
As of now, the first full scale unit that entered commercial operation is a 2000 TPD advanced coal power plant which began producing 250 MW of electricity in the Tianjin area of China in early 2012.

2.5 Technology comparison in brief:

2.5.1 In general, since all the established technologies have their own merits and drawbacks and gasifiers across all technologies are operating across the globe, it is not feasible to make a firm judgement on this point. In many cases, the technology choice depends on specific factors for a given project. As of now, though entrained-flow type gasifiers form the bulk of IGCC across the globe, there are significant differences amongst the processes in respect of fuel feeding and firing, as well as gasifier geometry which in turn has potential implications for feedstock assessment and selection, fuel performance evaluation and in the troubleshooting of operational problems. Nevertheless, some primary comparisons on different fronts are given below:

2.5.2 **Dry Vs Slurry feed:**Slurry based systems have lower capital costs; however, they are less efficient because more of the fuel energy is converted to heat in view of the water content which reduces the efficiency of gasification. Further, it will also lead to more auxiliary power consumption. This becomes a deciding factor in case of low rank, high moisture fuels like lignite. In one case, the Canadian clean coal association has selected shell gasification technology for its lignite project in view of this. On the other hand, the primary drawback of dry feed is that it can operate only at moderate pressures thus limiting its efficiency.

2.5.3 **Air Vs Oxygen**: Air-blown gasifiers are less expensive since they do not have the Air Separation Unit(ASU), one of the essential parts of an oxy-blown gasifier; on the flip side, they produce a much lower calorific value syngas than oxygen-blowngasifiers. Since air contains almost 79% of nitrogen, it dilutes the syngas significantly.

It follows that this has a significant impact on the design of the combustion system of the Gas turbine. Further, because the nitrogen in air must be heated to the gasifier exit temperature by burning some of the syngas, air-blown gasification
is more favourable for gasifiers which operate at non-slagging conditions.

2.5.4 **Water-quenching Vs heat recovery**: The exiting syngas must be cooled down to ~100°Cin order to utilize conventional acid gas removal technology. This can be accomplished either by passing the syngas through a series of heat exchangers which recover the sensible heat for use in the steam cycle of the IGCC, or by quenching the syngas with relatively cold water. The quenched syngas is led through a series of condensing heat exchangers which remove the moisture from the syngas. Quench designs have a negative impact on the heat rate of an IGCC as the sensible heat of the high temperature syngas isconverted to low level process heat rather than high pressure steam. However, quench designs have much lower capital costs and at low fuel cost, this is an option.

2.6 Gas clean up:

2.6.1 Themain impurities required to be removed from the syngas exiting the gasifier before it is ready for firing in the gas turbine combustor are:

- Solid impurities
- NOx
- Sulphur

2.6.2 Particulate Removal: Ceramic fabric/ fibre (<900ºC) and bag type(<500ºC)
are used to remove solid impurities.

2.6.3 Acid Gas removal: Physical or chemical methods are used for acid gas removal.

2.7 Performance

2.7.1 **Efficiency:**

At present, there are no large size IGCC units for power generation units operating in the country. Abroad also, only half a dozen units have logged adequate operating hours. Most of these are based on advanced class Gas turbines F to H class and hence to some extent, the efficiency depends on the basic efficiency of the gas turbine.

2.7.2 The efficiency recorded at some of the major IGCC plants are listed below:

TABLE 2.4: MAJOR OPERATIONAL IGCCs

	Wabash Power Station, US	**Polk Power Station, US**	**Buggenum, Netherlands**	**Puertollano, Spain**	**Nakaso Japan**
UNIT SIZE	262	250	253	298	250
GASIFIER TYPE	Conco	Texaco	shell	Prenflo	MHI Airblown
FUEL	COAL	COAL	COAL	COAL	Coal
GAS TURBINE	7FA	7FA	SIEMENS 94.2	SIEMENS 94.2	MHI
NET EFFICIENCY, HHV, %	39.7	37.5	41.4	41.5	40 (42 on LHV)

2.7.3 The above efficiency figures by and large corroborate the data published in institutional literatures. As per the recent (Sept 2013) data published by US NETL (DOE), the band of net efficiency indicated for IGCC is 39.7% (ConocoPhilips) to 42.1 %(for Shell). [28]

2.7.4 However, for Indian climatic conditions, the predicted efficiency could be between 37 and 40%.

2.7.5 **Auxiliary power consumption**:

Based on the results of several studies, it appears that the IGCC of medium size (500- 1000MW) consumes about 16 to 22 % of the gross power generated in Indian conditions. The main consumers are the compressors for ASU, oxygen and nitrogen.[28,29]

2.7.6 **Availability**:

One of the main drawbacks of the IGCC which resulted in cancellation of many projects is the reliability of operation. Here it needs to be mentioned that in the petroleum/ petrochemical industry, many IGCCs did not have significant availability issues since many of them were using refinery fuels which eliminated issues related to solid fuel handling. In power generation, since many of them are working using high ash fuel which creates problems in the gasifier and cleaning equipment by way of erosion, corrosion, fouling and pluggage of their high-temperature heat recovery units, the availability is cumulatively reduced. Even OEM's own data shows peak availability of even demonstration units around 85%.[30, 31, 32]

2.7.7 **Start up Time**:

i). General:

IGCC as technology units debuted in the chemical industry for gasification, and since such applications normally operated the gasifiers for prolonged periods within narrow process input variables, the start up time hardly mattered. However, power plants nowadays operate in a regime where frequent start up and shut down are routine. This is especially coming into stark focus when plant dispatches are prioritised for the renewable sector and thermal technologies using lowest cost fuel.[32]

ii). Air Integration between ASU and GT:

This is one of the features which influence the start up time of the IGCC unit. A fully integrated air system between GT and ASU will give maximum efficiency and minimum cost; however, this will lead to inordinate delays in starting the whole unit since the gasification unit will be fully dependent on the GT compressor for its air requirement. On the other hand, a 100% dedicated compressor for ASU will give the fastest start up period. In many cases, the integration between ASU and Gas turbine is partial which will strike an optimum balance between start up time, efficiency and cost.

Typical cold start up periods for IGCC plants are 80 to 100 hours, the lower range reflecting the dedicated compressor configuration, and the upper range with a fully integrated air system between GT and ASU.

Hot start up periods are in the vicinity of 6 to 8 hours.

OEM claim: As per the published information, MHI has claimed 15 to 18 hours cold start up time for its Nakaso (Japan) 250 MW demonstration unit which has been in operation for several years; however, this claim has not been independently verified.[33]

2.7.8 Load ramp up and operation flexibility:

IGCCs are inherently base load application units from a technology perspective. Inertia associated with ASU and gasifier against load changes typically limits their flexibility for fast load changes. Further, normally with diffusion burners which are commonly used in many units, the concentration of CO in the flue gas escalates below 60% of base load, potentially creating environmental issues. The minimum stable load of IGCC units is about 50 % and typical ramp up rates are about 3 to 4 % per minute. However, some literature [34] projects a far lower ramp rate of 1% per minute for ASU.

Multiple measures like having 2 x 50% units, storage of syngas, nitrogen and oxygen, co-firing with natural gas can improve the flexibility.[32, 35]

2.8 Water requirement:

2.8.1 The water requirement of an IGCC unit, in relation to conventional coal based units is about two thirds of a comparable coal based plant. Based on study results from the US a consumptive water of 850 m3/ hr has been indicated for a 622 MW net capacity.

2.9 CAPEX AND OPEX.

2.9.1 The project costs of IGCCs already operating at different locations are tabulated below[36]:

TABLE 2.5: PROJECT COSTS OF SELECTED IGCCs

	Wabash Power Station, US	Polk Power Station, US	Buggenum, Netherlands	Puertollano, Spain
UNIT SIZE , MW	262	250	253	298
FUEL	COAL	COAL	COAL	COAL
PROJECT COST $US / kW	1600	2000	2400	2900

2.9.2 However, of late, it has been reported that the investment cost estimated for several IGCC projects was found to have escalated significantly- in some cases up to 80%.

- A case in point is Duke Edwardsport where for 618 MW (W/O CO_2 capture), the original estimate of $2Billion; now it stands at $3.4 Billion or 5500/ kW.
  (***Ref: www.emersonprocessxperts.com***)

2.9.3 Possibly in view of recent developments of such cost escalation, in US, very recently EPRI has gone on record on this front specifically stating that the actual costs have significantly gone up.

2.9.4 The institutional data obtained have been tabulated below:

TABLE 2.6 : ESTIMATED CAPEX OF IGCCs FROM UNITED STATES

Sl no.	DESCRIPTION	US EIA(DOE) May 2013	US NETL(DOE) Sept 2013	BLACK & VEACH EST 2011	REMARKS
1	SIZE, MW, Net	1200	622	590	EIA estimate includes 7% Contingency. B&V Est indicates an error of +/- 35 %.
2	COST BASE	2011	-	2010	
3	CAPEX, $/ kW	3700	2500	4000	

TABLE 2.7 : ESTIMATED CAPEX OF IGCCs FROM EUROPE

Sl no.	DESCRIPTION	ESTIMATE
1	SIZE, MW, Net	-
2	COST BASE	2011 (EIA)
3	CAPEX, €/ kW	1800

TABLE 2.8 : ESTIMATED CAPEX OF IGCCs FROM CHINA[37]

Sl no	DESCRIPTION	ESTIMATE	
1	SIZE, MW, Net	300	400
2	COST BASE	NA	
3	CAPEX, $/ kW	1400	1200

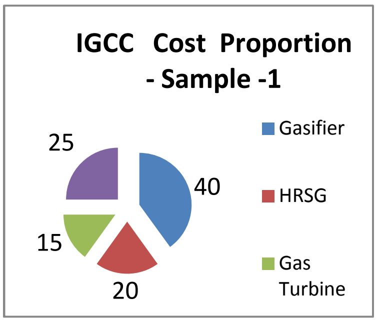
2.9.5 On review of the figures in tabulation, the following can be inferred.

2.9.6 For the US, in respect of Capex, significant variation can be seen between the estimates given by the two arms of DOE. Further, estimate by EIA Consultant are in close range(+/- 10%); However, Consultant's estimate shows an error to the extent of 35% which appears to be an indication of the uncertainty of cost as reflected in the excessive escalation reported in the two projects currently at an advanced stage.

2.9.7 In the case of Europe the reliability of the cost data appears suspect keeping in view that the detailed base of cost estimates have not been given.

2.9.8 In case of China, the reported cost is significantly lower; this appears to be generally in line with the finding of EIA for projects in China, where a country factor of 0.6 to 0.65 is applied by the US and EU, presumably keeping in view the equipment and services sourcing possibility from local manufacturers and suppliers.[38]

2.9.9 Break up of Capex: Two examples of the broad proportion of IGCC cost available are presented below:



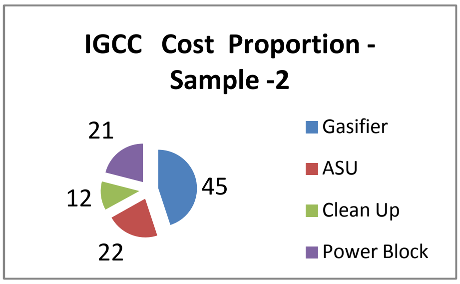


CHART 2.1 : IGCC COST SAMPLES

2.9.10 Sample 1 is from USDOE, published very recently after the significant cost escalation reported from two on-going US projects.

2.9.11 Second is the projection given for RIL IGCC project in 2009. But the RIL project, apart from power generation, also makes a number of downstream projects and hence the process is customised.[39]

2.10 Recent advances/on-going research in IGCC arena.

2.10.1 Despite the technology existing for decades across the globe, IGCC is yet to evolve into an operationally reliable and economically sustainable technology for power generation. Hence, research has been on-going in this space with active support from policy makers. The added momentum for this 'push' has been given by seeking 'cleaner' energy in view of the global effort to contain the pace of climate change. These researches have been on the improvements in / diversification of the basic technology available and component/ subsystem development/improvement.

2.10.2 Basic Technology Diversification: A number of new technologies, some offshoots of the existing processes, have been found to have the potential to emerge in the next few years after going through pilot testing.

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One of the prominent ones worth mentioning is the Pratt and Whitney developed Rocketdyne gasifier. The major features reported are a compact flow gasifier with 90% gas volume reduction which will facilitate factory fabrication, and fuel flexibility.[40]

2.10.3 Based on a study under the IEA Clean Coal Centre, the following two have been listed as candidates for power generation.
- Advanced IGCC/ IGFC with energy recovery
- Oxy-fuel IGCC with CO2 recirculation for CO2 capture.

2.10.4 MHI has diversified into Oxy-blown gasification and has been working on the first major project for Hydrogen Energy California (HECA), for co-production of power (400MW gross, 300 MW net) and fertiliser from petcoke and coal. The CO2 is to be used for enhanced oil recovery. According to the US DOE, the project is currently in the environmental clearance stage and construction is planned to begin in 2015 with completion slated for 2019.[41]

2.10.5 Component / Subsystem development: A number of drawbacks of the existing technologies have been in the focus research/ demonstration phase; a few of these are listed below.

2.10.6 CO2 Slurry in place of water slurry: Under a study by MIT in 2013, replacing water with CO2 is expected to improve the efficiency of low ranked coal by about 30% and LCOE by 20%.[42]

2.10.7 GE has been evaluating with dry feed gasifier technology and testing had been going on from Oct 2011 to March 2013.

2.10.8 Development of Solid Pumps for uninterrupted dry-feeding systems of high moisture coals like lignite is also being pursued.[43]

2.10.9 As per the IEA Clean Coal Centre, ConocoPhillips (now part of CB & I) are reportedly working on a variation of their E-Gas system that would have a taller reactor and operate at higher pressure.

2.10.10 Gas clean up: Clean-up of the syngas exiting the gasifier have been one of the major challenges faced by the gasification industry, especially those in the entrained flow space.

2.10.11 The existing system involves significant cooling of the syngas to an acceptable temperature level for cleaning up media. This necessitated using cooling water to cool and then heat up the gas for firing in the gas turbine, with its attendant Capex and Opex.

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As per the information available with the US DOE, a pilot program has commenced towards building a hot gas clean up system titled Warm Gas Clean Up (WGCU) aimed at cleaning the syngas between 150 °C and 370 °C. Preliminary findings reveal that overall Capex and LCOE should get reduced by 5- 10%.[44]

2.11 Environmental Performance of IGCC:

2.11.1 As a technology for power generation, IGCC is yet to mature since few plants are operating in the world. However, the gasification technologies have been in use in the chemical industry for several decades with petroleum based feed stocks. Hence it may be premature to make a judgement about its compatibility with the environment from the standpoint of a proven technology. However, based on the feedback received from demonstration plants across the world, the primary opinion is converging towards accepting it as capable of being a frontline environmentally friendly technology in relation to the competing technologies currently available especially those built on solid fuels.

2.11.2 IGCC technology is inherently environment friendly. In IGCC, pollutants like sulphur-
dioxide and oxides of nitrogen are reduced to very low levels by primary measures alone, without down-stream plant components and additives like limestone.

2.11.3 A typical comparison of emission levels from IGCC and PC technology with Indian coal is shown in the following chart.

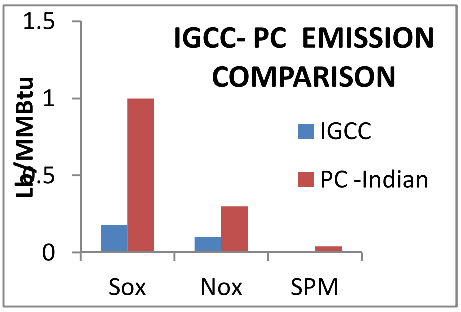

CHART 2.2: EMISSION COMPARISON : PC Vs IGCC

2.11.4 The significant improvement in performance of IGCC can be observed from the chart.

2.11.5 The environmental aspects broadly cover the following groups:

- Gaseous emissions to the atmosphere.
- Effluent water discharge into the ground / seepage into surrounding areas.
- Nuisance due to solid ash and slag residues.
- Handling of by products, like sulphur, if applicable.

2.11.6 Air emissions:

i). Unlike a conventional power station which oxidizes the sulphur and nitrogen to produce SOx and NOx, in IGCC processes the sulphur and nitrogen are reduced to H2S and NH3 in the gasifier and both can be removed from the tail gas stream.

ii).Trace elements: Unlike combustion, since IGCC operates in an air starved condition or in a reducing atmosphere, this makes the trace elements present in the coal highly volatile. As per the information available, many of these trace elements can be cleaned up without letting them into atmosphere; however gas clean up is a relatively expensive affair in gasification. The only major exception is mercury, which is relatively easy to remove from IGCC when compared to conventional PC fired plants.

2.11.7 Water based waste:

i). The waste water treatment from cooling water/ raw water make up is similar to the conventional plant.

ii). However, IGCC has a good amount of process water waste from syngas clean up and this typically contains high concentrations of dissolved gases and, in most quench and wet cleaning systems, species washed from the syngas. These are predominantly sulphur, chloride, cyanide and ammonium species. Existing IGCC plants treat their process water using commercially available treatment and crystallisation systems and in many cases are able to completely eliminate process water discharge.

Since the overall water requirement in an IGCC plant is appreciably lower than an equivalent rated PF unit, existing industrial systems are expected to be suitable for the management of most process water treatment requirements.

2.11.8 Solid waste disposal:

The largest solid waste stream from entrained flow gasification systems is slag produced from the coal mineral matter. In an entrained flow gasifier based IGCC, this is usually produced in the form of a glassy frit and is potentially marketable for use in the cement industry, for aggregates, road bases etc.

2.11.9 Safety aspects:

When compared to a conventional coal based plant, the only area where the risk of fire and explosion is higher in IGCC is the gasifier, which by the Dow F&EI, has a rating of 168 compared to 107 for a conventional boiler.[29]

2.12 Indian experience and update.

2.12.1 Reliance Industries:

i). The salient features of the IGCC project of Reliance Industries at their Jamnagar refinery are :

- Project in two phases
- First phase to have 4 modules, with 2 gasifiers per module
- Each gasifier to have a feed rate of 2900 tpd of petcoke
- Each gasifier to produce 272 000 Nm3/ hr syngas
- Gasification technology based on entrained flow with O2 as oxidant
- World's largest air separation unit (ASU)
- Phase – 2 to add two more modules.

ii). As per the data available as of now, the project is scheduled to start up in the second quarter of 2015.[45]

2.12.2 **Jindal steel and Power**:

JSPL is reportedly in the final stage of commissioning its 222000 Nm3/ hr gasification plant established with Lurgi technology, at their Angul works, Orissa. However, the syngas generated is to be used for steel production.

2.12.3 **BHEL Efforts:**

i). BHEL has operated a 6 MW moving bed gasifier at their Trichy works for last few years. The unit is reported to have logged cumulatively more than 10000 hours.

The salient features are:

- Technology : Moving bed
- Coal : Singareni collieries with ash content of ~ 37 %.
- Capacity : 150 TPD
- Power generation : 5.3 MW

ii). They have subsequently carried out another pilot project at their R&D unit at Hyderabad for a 18 TPD AFBG which has logged about 800 operating hours.

iii). Apart from this, BHEL had commenced a demonstration project at APGENCO Vijayawada works for a 125 MW project with an outlay of Rs 9000 Million; subsequently the project was scaled up to 180 MW; however, the cost shot up to Rs 24,000 million. The reason for the significant escalation is not known. It is reportedly at a standstill in view of the funding issue.[109]

iv). Recently BHEL and NTPC have tied up together for a 100 MW project at an estimated cost of Rs 700 Crores, to be mutually shared between them.

v). It is also reported that NTPC is pursuing an independent IGCC project at Dadri in collaboration with USAID.

2.13 Barriers for adoption in India:

2.13.1 As already stated, though an attempt for installing a demonstration plant in India had commenced in the past decade itself, so far not much progress has been made on this. From the available data, some of the factors which have contributed to this are described below.

2.13.2 Maturity of Technology :

Even overseas, IGCC is yet to be considered as a mature, reliable technology for power generation. As per one report, in the US which has a number of IGCCs operating, its department of energy considers it may take two more years for the technology to mature.

Though BHEL has been operating a 6 MW IGCC unit at their Trichy works, the basic technology used is the moving bed gasifier. As explained earlier, these cannot be used for large scale power generation. On the other hand, matured entrained flow technologies may again be problematic with high ash Indian coals.

2.13.3 Technology- Compatibility with Indian Coals:

First and foremost, keeping in view the sensitivity of electricity price in India and the significant cost of IGCCs reported from recently developed units abroad, it will be necessary to go for large size units (for leveraging economies of scale) if at all policy decisions are taken for implementing IGCCs.

For large sizes units, the only matured technology as of now is entrained flow gasifiers.

However, the ash loading per unit energy India for Indian coals will be about 7 – 10 times when compared to the average quality of coal available overseas. This may preclude the use of entrained flow gasifiers operating at high temperatures. It is worth noting that even with good quality of coal with moderate ash loadings, there have been problems with gasifier operations reported from operating units. The availability of IGCCs has been only around 80 to 85 % so far.

At the same time, the conventional fluid bed technology may not be suitable for large capacity units in view of their low efficiency.

Hence a more likely candidate could be transport gasifiers being developed which trade off between the high efficiency offered by entrained flow and the non-slagging characteristics of fluidised bed.

2.13.4 Reliability:

The stand-alone installations in India may be significantly expensive especially in view of their poor reliability unless multiple units are planned at a location.

2.13.5 Liberal environmental norms:

One of the primary reasons for delay in development and adoption of IGCC in India is the far lower environmental norms.

2.13.6 Uncertainty in predicting the cost:

This is by far the single most important factor in delaying the development; as already mentioned above, even in advanced economies, the costs of IGCCs estimated with the help of established tools have gone haywire. This has happened in India also going by the demonstration project cost of APGENCO 180 MW which saw a significant increase from the earlier estimate. At the current levels, the cost appears to be more than double the cost of an identical sized pulverised coal project.

2.13.7 Ownership of Intellectual property rights (IPR):

It is reported that an earlier attempt of a joint venture between NTPC and BHEL could not reach fruition in view of the dispute over the IPR of the technology being planned for development. This issue reportedly has now been resolved.

2.13.8 Component availability:

i). The major cost- bearing components of the IGCC units (apart from power block) are

- Gasifier
- Air separation unit
- Clean up unit

ii). As of now, most of these components are only available with overseas vendors. However, in case a policy decision is taken to go for IGCC units on a large scale, the government can explore the feasibility of seeking phased manufacture of critical components in the country, along the lines of power projects, which received good response.

The major vendors for other than gasifiers are tabulated below:

TABLE 2.9 : VENDOR LIST FOR MAJOR IGCC SUBSYSTEMS

Air separation Unit	Praxair, Air Liquide, Linde
Acid gas removal	Dow and BASF, UOP, Lurgi, Air Liquide, Linde, Shell.
Water gas shift	Haldor Topsoe, Sud Chemie, Johnson Matthey

2.14 Estimated Capex for India:

2.14.1 As per the forecast released by US NETL in Sept 2013, the installed cost at a stabilised level for an IGCC will be around $ 2500 / kW. This translates to about Rs 160Million / MW at the exchange rate as on date.

2.14.2 The revised estimate for the APGENCO project is Rs 24000 Million which works out to ~ Rs 130 Million/ MW.

2.14.3 However, The IGCC costs are also geography-specific to some extent with issues like local participation, country risk etc. normally being factored in by prime equipment vendors/ contractors.

2.14.4 As mentioned earlier, for projects in China, a country factor of 0.6 to 0.65 is applied by the US and EU, presumably keeping in view the equipment and services sourcing possibility from local manufacturers and suppliers. This point is perhaps corroborated by the recent cost data released for the Greengen project at Tianjin where for a 250 MW project, the cost recorded is $ 1 Billion or $ 4000/ kW. Since this is perhaps the first project in China for power application, this cost needs to be compared with the cost figures for Kemper county (this needs to be compared with the cost of 5500/ kW for Duke Edwardsport project mentioned earlier (5500/ kW).

2.14.5 It however, needs to be mentioned that as of now, a number of gasification projects are planned in China and many are under implementation also (though all are not only for power), the probability of component sourcing from the local industry would be far higher when compared to India, at least in the short term.

2.14.6 Keeping in view the points discussed above, the projected costs forecasted below are for first of a kind projects. Both optimistic and pessimistic scenarios have been considered.

TABLE 2.10: ESTIMATE OF IGCC COST FOR INDIA

Nominal Station Size, MW	Installed cost		Remarks
	Optimistic	Pessimistic	
2000 - 2500	Rs 100 – 120Million/ MW	Rs 180 – 200Million/ MW	5% increase for Lignite base

2.15 Probability of adoption of IGCC in India.

2.15.1 From a technology perspective, it is one of the better environmentally friendly technologies currently available in view of its significantly lower load on the environment. On a net power basis, the NOx, SOx and SPM generation from IGCC units are lower as compared to a conventional supercritical/Ultra supercritical unit. Further, the water requirement is about 30 to 40 % less when set off against pulverised thermal units. Hence there is basic suitability for this technology from an environment standpoint.

2.15.2 As of now, the installed cost for IGCCs is at least double as compared to the conventional units, even in advanced economies (where considerable research by multiple agencies and with significant state funding has been going on for several years).

2.15.3 Indian coals (including lignite) are not suitable for adoption to matured gasifier technology (entrained flow) currently available for large units. However, it may be possible to use washed coal with lower ash content. Alternatively, the transport gasifier like the one being developed by KBR may be suitable.

2.15.4 While lignite could be used with fluidised bed gasifier, overall economics may not be favourable to lignite in view of the low efficiency associated with the fuel.

2.15.5 At this stage, unless long term and reliable incentives are in place, private players may not be inclined to adopt IGCC technology.

2.15.6 Hence if IGCC has to be adopted for the long term, negotiation for at least 10 GW to 15 GW capacities along with agreements for technology transfer for component manufacturing may be the most prudent path forward.

3.0 UNDERGROUND COAL GASIFICATION

3.1 Introduction:

3.1.1 Underground coal gasification (UCG) is essentially in-situ gasification at underground coal mines by injecting the appropriate oxidant.

3.1.2 The process is primarily deployed for coal seams at depths transcending the reach of cost-economic conventional mining processes.

3.1.3 The method in its bare basics involves drilling two parallels wells, one for injection of oxidant (air, oxygen or steam).

3.1.4 UCG technologies offer environmental benefits relative to traditional coal utilization including lower air emissions, no above-ground coal mines and combustion waste, and less intense surface development.

It however, comes with serious environmental risks for the local habitat including the potential for groundwater contamination and reduction. Further at shallow depths, it can also pose a risk of surface subsidence.

Nevertheless, through prudent site selection, experience gained from earlier projects and operational practices based on pooled expertise the risks can be mitigated substantially.

3.1.5 As per a report by US national energy technology laboratory, (NETL), only one-sixth to one-eighth of the global coal reserves are economically mineable with the current technologies and hence there is significant potential for UCG as a medium for uplifting the utilisation of available coal reserves.

3.2 Difference between UCG and Surface gasification.

3.2.1 Though the primary reactions in both are identical, there are some basic variations in the products obtained between these two processes, as tabulated below:

TABLE 2.11: COMPARISON BETWEEN UNDERGROUND AND SURFACE GASIFICATION

Syn-gas Constituent	UCG (%)	Surface Gasifier (%)
Hydrogen	30	36
Carbon Monoxide	17	52
Carbon Dioxide	33	10

Syn-gas Constituent	UCG (%)	Surface Gasifier (%)
Methane	18	0
Nitrogen	0.1	1.
Tar	0.1	0
Hydrogen sulphide and COS	0.2	0.4
C2+	0.9	0
H2+CO	47.6	88.5
Calorific value, MJ/SCM	13.3	10.7

Note: the values furnished are typical; the UCG heat value has been reported to vary significantly from 5 MJ/ SCM upwards.

3.2.2 However, a number of factors decide the composition for a given case. E.g.: Deeper seams produce more CH4 and less H2 and CO.

3.2.3 Major observations from the above table are :
i). The heat value of the UCG gas is about 25% more than the typical syngas generated by IGCC, owing to significant content of methane.
ii). CO_2 in UCG is high compared to IGCC syngas.
iii). UCG gas contains significant amount of tar.

3.2.4 Further, one basic difference between the gasification process is that unlike IGCC, in case of UCG, the processes of drying, pyrolysis and char gasification progress simultaneously.[46]

3.3 Technology of extraction:

3.3.1 So far two technologies have been used widely for gasification and extraction:

- Linked Vertical Well (LVW) method
- Controlled Retractable Injection Point (CRIP) method

Apart from these, Ergo Energy, one of the well-known players in the UCG arena have developed and deployed a patented technology at Chinchilla in Australia.[47]

3.3.2 Both the methods primarily rely on two linked boreholes to inject the oxidant and remove the syngas. LVW method uses vertically drilled wells to access the coal seam and different techniques to link the boreholes. On the other hand, the CRIP method relies on a combination of conventional drilling and directional drilling to access the coal seam and physically form the link between the injection and production wells.
However, based on available data from a previous trial, it has been figured out that normally, LVW methods, which are relatively less expensive, are more suited to shallow coals seams, while in deeper coal seams, interconnection between the wells becomes more complex and the CRIP method is found to be more compatible for such cases. The methods are briefly described below.

3.3.3 Linked Vertical Well (LVW) method:
The LVW method uses what can be termed as reverse combustion, (RC), for opening up internal pathways in the coal seam. In this method, the coal is ignited from one of the vertical wells and air/oxygen is introduced

into the coal from the other well. The combustion front then moves toward the air/oxygen, forming linkages between the wells by progressively consuming small lumps of coal and forming tube-like channels as it goes. Once the linkage is established, forward combustion, (where the combustion front moves in the same direction as the injected air/oxygen toward the production well), is used to gasify the coal.

It is reported that for coal seams lying at shallow depths,the LCW method can use larger size wells, and consequently greater syngas flow rates could be achieved using LVW than with CRIP.

The main drawback of the LVW method is that, owing to its reliance on the natural permeability of coals, it may not be an ideal candidate for low-permeability coal, or deeper coal seams (>300 m), which tend to be under great pressure and consequently have reduced permeability.

3.3.4 Controlled Retractable Injection Point Method

This method is adopted from oil and gas industry. A pictorial representation of the CRIP method is shown below:

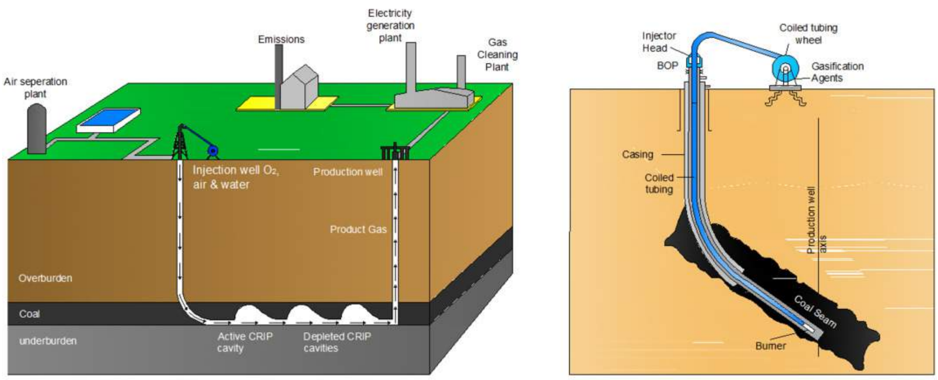

FIG 2.8 : CRIP TECHNOLOGY – SCHEMATIC

The CRIP techniques use primarily directional drilling techniques for both the injection and production wells. The injection and production wells are drilled from the surface as inclined holes, and extended as parallel horizontal boreholes within the coal seam, and then curved to intersect the vertical Ignition Well.

3.3.5 The impact of the CRIP method on overall economy of large scale UCG are multi-fold:

i) On one hand, the gasification efficiency can be maintained within a narrow band which is not possible with LVW method. This is because as the UCG reactor grows, more and more of the barren roof rock is exposed, which leads to a steady drop in gasification efficiency. In the CRIP method, the injection point can be retracted within the coal seam when fall in efficiency is observed.

ii) Further, the large spacing between the injection and production wells also means that fewer boreholes are required to gasify a given volume of coal, and so the CRIP methods have a smaller surface impact than LVW methods.

3.3.6 Single Well Flow Tubing (SWIFT)[122]

Introduced fairly recently, (in 2012), by Portman Energy, this process utilizes a single, fairly large well for injection of oxidants and extraction of product syngas via networks of coiled tubing. The unique design of this method is, it uses a single casing tube string which is enclosed and filled with inert gas for corrosion prevention, leak monitoring, and heat transfer. Horizontally drilled lateral oxidant delivery lines into the coal and a single or multiple syngas recovery pipeline combusted a larger area of coal. The developer claims that the development cost for SWIFT technology is significantly low. The facilities and well heads are concentrated at a single point pipelines, facility footprint, and reducing surface access roads.

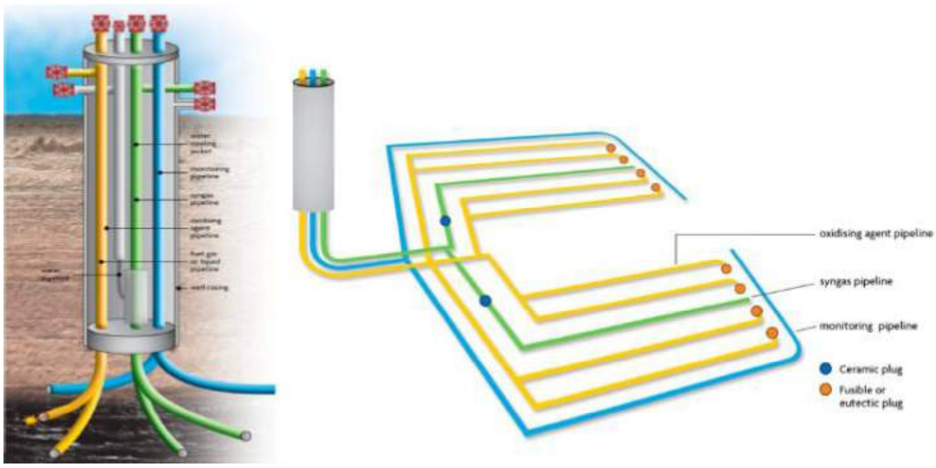

FIG 2.9: SWIFT TECHNOLOGY – SCHEMATIC

However, being a nascent technology, the method is yet to be operationally proven for large sites.

3.4 Clean up of the UCG gas:

3.4.1 Because the processing of the coal is kept underground, surface and air emissions of sulphur, nitrous oxides, and mercury are dramatically reduced; hence cost of clean up of UCG gas would be significantly lower as compared to surface gasification. Still, gas clean up is essential since product gas coming out of the well can potentially contain acid gases, mainly hydrogen sulphide and carbonyl sulphide along with traces of mercury.

3.4.2 The degree - and hence the process – of gas clean up depends on the eventual use. Confining to use in power generation, the description that follows herein relates to the end use as fuel for gas turbines.

3.4.3 Since the main contaminant is(residual) tar and allied particulate matter, the preferred cost-effective clean up is water- wash scrubbing.

Post-scrubbing, excess water is removed by cooling before the gas is compressed. Sulphur is normally present as carbonyl sulphide (COS) which is first converted into hydrogen sulphides and subsequently removed by chemical or physical methods.

Mercury is removed by activated carbon beds.

3.5 Siting and its influence on the Cost-economy of UCG

3.5.1 Five stages of risk were identified when developing UCG: site selection, design, operation, shutdown and decommissioning. The most important stage is site selection.

3.5.2 As a technology, UCG has been in existence for the last 4 decades or so. Experience of several pilot and demonstration projects across different countries have shown that economy and sustainability of the UCG operation depends to a very large extent on selecting an appropriate site. Major findings on this based on published literature on the subject are listed below:

i). Coal composition and rank: Low rank coals are better since they generally shrink when burned, which improves the connection from the injection to the production wells.

However, the drag on low rank coals is that their energy content would be low and hence the yield.

Extremely high ash content in the coal has the potential to inhibit the UCG process itself.

Similarly high sulphur content will put pressure on the gas cleaning system.

As for moisture, it should be kept to a moderate level which while sustaining combustion should facilitate maintaining acceptable syngas energy. A value between 10 and 15 % can be considered optimum.

ii). Depth of seam: Based on the various studies, a depth more than 100 m but less than 200 m is expected to trade off between risk of subsidence and contamination of ground water as well as cost of drilling.

iii). Coal seam thickness: A thickness between 2 to 15 m is preferred in order to ensure gas quality within acceptable thresholds. Too low thickness will produce gas with more CO_2 and lower amount of the combustibles (CH4, CO and H2).

iv). Probable tectonic disturbance is another area needing focus since major faulting from the gasification zone to surrounding strata or to the surface has the potential to provide a pathway for water inflow, gas migration or contaminant transport. The fault with throw more than seam thickness will be a hindrance to the fire front movement during gasification. The consensus of various researchers veers around 50 m as the threshold from gasifier location.

v). Reserve: This is a factor for which there is no one recommendation since the cost- economy of UCG varies significantly across geographies besides the intended end use of the gas produced. Keeping in view the fact that:

- Few modern UCG plants are operating anywhere in the world as of now and hence even investment cost can be determined only on an order-of-magnitude basis,
- India has just taken the first steps in the commercial operation of UCG,

a best judgement would call for a site having an adequate reserve for a Power plant of a minimum size of 2000 - 3000 MW.

3.5.3 The typical UCG siting requirement is tabulated below. [48]

TABLE 2.12: RECOMMENDED CHARACTERISTICS OF UCG SITE

Parameter	Desired Value	Remarks
Coal thickness (m)	2 – 15	
Thickness variation (% of seam thickness)	<25	
Depth (m)	92 –460	
Dip (degree)	0 – 70	
Dip variation (degree/31 m, 100 ft)	<2	
Single parting thickness (m)	<1	
Total parting thickness (% of seam thickness)	<20	
Fault displacement (% of seam thickness)	<25	
Fault density (Number of faults/31 m)	<1	Number of faults/100 ft
Coal rank	Low rank bituminous	≤ Bituminous
Coal moisture (wt%)	<15	
Ash content (wt%)	<50	
Coal sulphur (wt%)	<1	
Thickness of consolidated overburden	>15	
Seam permeability (mD)	50 – 150	
Immediate overburden permeability (mD)	<5	above the seam
Distance to nearest overlying water –bearing unit (m)	>31	
Coal aquifer characteristics	Confined	
Nearest producing well completed in coal seam (km)	>1.6	
Available Coal Resource (Million m^3)	15.4	~543 x 10^9 cubic ft for 20 year-long operation

3.5.4 Another recent study[123] lists the following characteristics of an ideal site for UCG. It can be seen that while some parameters are identical/ in close range, there are differences in others. Further, some additional data also has been provided.

TABLE 2.12 B: RECOMMENDED CHARACTERISTICS OF UCG SITE (ALTERNATE)

Parameter	Desired Value	Remarks
Coal thickness (m)	5–10	
Thickness discontinuity, m	1	Avoid seams with variable partings/discontinuities
Number of seams to be gasified	–	Avoid seams with overlying coal within 15m
Depth (m)	300 –2000	
Fault displacement (% of seam	<25	

Parameter	Desired Value	Remarks
thickness)		
Fault density (Number of faults/31 m)	<1	Number of faults/100 ft
Coal rank	Low rank bituminous	Free swelling index should be low. Sub bituminous or lower rank, ideally not coking, non-swelling coals.
Coal moisture (wt%)	<35	Preferred 7-35%. Controlled inflows of water or high moisture contents are desirable especially after initiation of burning
Ash content (wt%)	<50	
Coal sulphur (wt%)	<1	
Thickness of consolidated overburden	>15	
Seam permeability (mD)	50 – 150	
Distance to nearest overlying water –bearing unit (m)	>100	
Coal aquifer characteristics	Confined	
Available Coal Resource (Million Ton)	>3.5	For 20 year operation. Depend upon gas utilization and profitability.
Distance from populated areas(km)	>1.6	> 100 people
	>200m depending on site conditions	If many major faults then site specific calculation required to be carried out for the accurate estimation of the distance
Distance from major highway and rail (km)	> 0.4	
Distance from rivers and lakes	> 0.6	
Distance from active mines	> 3.2	
Distance from abandoned mines	>1.6	
Hydrology	Non aquifer strata is preferred	Non porous strata <30%, Impermeable <5%, Moderate water ingress. Avoid potable aquifer and large water bodies
Geotechnical strata properties	Rock strength: Uniaxial compressive strength range 50 to 250 MPa. Density greater than 2000kg/m3	Avoid excessively fractured, faulted and broken rocks as they may cause water inrush or product gas and contaminant leakage
Presence of Coal bed methane		Depends upon economics or commercial value of CBM deposit and its interoperability with UCG

3.5.5 It can be seen that the data presented in Table 2.12 B is fairly nascent presumably factoring in the pooled experiences during the intervening period (2010- 2014). Of course, certain variations in the data presented (between Tables 2.12 A and 2.12 B) may have been influenced by differences in the local geological strata across continents. Together, however, both the tables should give a range of various parameters towards an informed decision on a preliminary siting of UCG projects.

3.5.6 Basic comparison between deep and shallow sited projects: The primary comparison between deep cited (> 1000 m) and shallow cited UCG projects are listed below:

- Deep sited projects need more dewatering.
- Further, deep sited locations will call for oxygen injection for economy considerations
- They generally produce UCG gas containing more methane
- From an environmental angle, deep sited projects are relatively less vulnerable to subsidence and ground water contamination.
- In view of the higher pressure of operation, process control is easier with deep sited UCG projects.

Of course, deep sited projects do incur significantly higher Capex and Opex.

3.6 Experience from Overseas countries:

3.6.1 Australia:

i). The Cougar Energy Pilot project had created environmental issues arising out of leakage of benzene and toluene into local ground water; subsequently, the entire UCG project activities have come to a standstill in Queensland province. Further, this incident has propelled the regulators to explore the measures to be incorporated in the regulations for precluding such incidents.[49]

ii). Apart from this, recently, another UCG project in Queensland operated by Linc Energy has also reportedly been de-commissioned in view of the environmental damage[124].

ii). However, as per Carbon Energy, another UCG operator, their venture into underground coal gasification (UCG) technology through a pilot project at Bloodwood Creek has been successful. Right now they are reportedly producing 1.5 MW from the 5 MW plant fed from the UCG wells. They claim their proprietary technology keyseam® has been successful after 5 years of operation.

The second phase of development at the Bloodwood Creek site is expected to see an additional 25MW power station, while the third phase involves a commercial-scale 300MW power station.

3.6.2 USA: Wyoming has been identified as one of the states with a large potential for UCG. However, reports suggest initial setbacks in UCG projects on environmental concerns. As per one report, in the state of Wyoming, over-pressurisation of the reactor and improper site selection had resulted in a plume of benzene and volatile organic compounds to local fresh water aquifers. [50]

3.6.3 Recent reports suggest that a developer Lincoln Energy got permission from the state administration for a demonstration project.

Similarly in Alaska, a consortium of CIRI and Linc Energy is reportedly planning to develop a UCG, but for methanol, ethanol or fertiliser production. The project details suggest a 3500 feet (~1100 m) deep coal seam with a thickness of 50 – 60 feet (15- 18 m)(*akbizmag.com, Aug 2013).*

3.6.4 China: From China, overall, 30 odd projects have been reported so far. Of these, 3 of the largest are in the Shanxi province, Inner Mongolia, with a combined reserve of 15 billion tons. *(news.xinhuanet.com, Mar 2013)*

3.6.5 Russia: A project in Chukotka province is being studied by Australian UCG operator Linc Energy. *(www.themscowtimes.com, Aug 2013)*

3.6.6 South Africa: Reports suggest Sasol has initiated trial projects at Secunda as a potential feedstock for Coal to liquid. In general, SA appears to be serious about long term development of UCG as per the reports quoting the DOE.*(www.miningweekly.com)*

3.6.7 Uzbekistan : In the recent past, Australian mining company Linc Energy has taken equity in the world's first UCG based power plant operating for the last 30 years at Angren.*(www.lincenergy.com)*

3.7 Environmental Risks associated with development of UCG:

3.7.1 With a lot of positives going for UCG as an economical method of extracting energy from un-mineable coal seams, by far the biggest hurdle in its fast paced development has been the concerns about potential longterm damage to the environment.

3.7.2 Recent report from UK says the government is putting a pause on the leases in view of severe public opposition out of environmental concerns. (*Ref: Reuters, 1st Oct 2013*)

3.7.3 Another report says that in Spain, there was a methane explosion at an underground mine 550 m deep that damaged the reactor, but no contamination was reported.[51]

3.7.4 Recently, (Jan 2014), Alliance Secretariat, a body representing the local authorities in the industrial areas of England, Scotland and Wales has also flagged [127] the issue concerning the environmental impacts of UCG operation. They have identified the following aspects in this connection:

- Protection of underground aquifers
- Adequate depth to avoid surface disruption
- Need for environmental impact assessment and risk analysis
- Impact of new environmental legislation

They express the opinion that views of regulators, including Mineral Planning Authorities, need to take precedence over the views of private companies in decision making.

3.7.5 They have, however, cautioned that that while more needs to be understood about the environmental impacts of UCG at the extraction and post-extraction stage; total opposition to UCG is unreasonable. Though earlier, environmental impact was considered as one of the routine factors to be flagged for any typical project, after the Australian experience of the abrupt stoppage of the pilot project in Queensland province, this issue has propelled thinking amongst policy makers and regulators alike about the safeguards to be put in place on UCG projects.

3.7.6 Two major concerns associated with environmental impacts;

- Potential groundwater contamination
- Subsidence of ground above the UCG gasifier.

3.7.7 Ground water contamination: Ground water contamination can be caused by several means:

i). Migration of VOCs in vapour phase into ground water.
ii) Upward migration of contaminated ground water: This can happen due to thermally driven flow away from reactor or boundary effects from liquid density gradients resulting from changes in dissolved solids and temperature. In some cases, change in permeability of reservoir rock due to gasification process also can cause this.

3.7.8 Typical Groundwater Chemistry Before & After Pilot UCG Burn is tabulated below:[50]

TABLE 2.13: TYPICAL GROUND WATER CHEMISTRY AT UCG SITE

Chemical Constituent	Before Burn (mg/l)	After Burn (mg/l)
Ca	20	200
Mg	5	15
Na	100	300
HCo_3	300	500
Sulphate	4	1150
H_2S	0.02	0.4
CL^-	30	40
NH_3	1	100
TDS	350	2300
Phenols	0.1	20
TOC	20	200
CH_4	0.42	0.16

3.7.9 Contaminants associated with the UCG process: Coal tar, VOCs, PAHs, heavy metals (mostly lead based), ferro-cyanides and tar emulsions are the common contaminants.

3.7.10 Subsidence: Subsidence occurs when ground sinks. While one of the reasons is the shallow depth of UCG reactors, sometimes, the change in the ground water pattern can also cause subsidence. In general, UCG subsidence results in height reduction and would affect only land directly above the gasified coal seam. The magnitude and characteristics of subsidence depends on many factors including seam depth, rock stiffness and yield strength, disposition of seam, the stress resulting from gasification, and other geological properties.

3.7.11 The EIA report prepared for a 60 MW project in South Africa estimates that the subsidence expected from the project with a coal seam 330 m below the ground and having a seam thickness of 3.2 m, is < 1m. Though this is also site-specific, it does give an order of magnitude range of subsidence.

3.7.12 The report further states that by undertaking certain measures like hermetically sealing the bore holes, skilful drilling of the wells, consistently maintaining a pressure differential between the gasifier and hydraulic pressure of the surrounding geological formations etc., it is possible to substantially lower the risk associated with potential ground water contamination.

3.8 Transportation of syngas pipeline

3.8.1 Since there are no modern UCG based power plants, not much published data is available on the feasibility of transportation of syngas pipeline, except one project which got stalled midway (March 2013) in the Alberta province in Canada. Here the project envisaged extraction of gas from coal located at 1000 m depth and transporting it to the 300 MW power plants located 60 km away. (*Ref: www.globalccsinstitute.com, Mar 2013*)

3.9 Cost- Economy of UCG

3.9.1 General: Since few modern large scale plants based on UCG are operational anywhere in the world, the nearest approximation could be the estimate of cost of gas generated from IGCC operations.

3.9.2 Several estimates have been made of the cost of an electricity plant based on UCG syngas. The main physical variables are the quality of the coal, depth and thickness of the coal seam, linking distance of the injection and production well and distance between the cavities.

↓

The projection of cost from Wyoming in the US is around $6/ MMBTU of gas. This is about double the current average price of gas in the US. [48]

3.9.3 The following data has been found for a study conducted for US UCG projects by the University of Indiana in 2011, with sensitivity to thickness of the coal seam for a depth of 250 m, for 3 coal seam thickness varying between 2.5m and 5.0 m.[48]

TABLE 2.14: TYPICAL UCG BASED ELECTRICITY COST

Description	Value	Remarks
No. of production wells	25 to 109	Lower range of values is for higher seam thickness where more no. of production and injection wells are considered and economies of scale leveraged in cost estimation.
No. of injection wells	51 to 218	
Syngas production cost, $/ MMBTU		
Min	3.42	
Max	8.03	
Annual O & M Cost, $Million	22.7 to 68.8	
Cost of Electricity, ¢/ kWh		
Min	5.27	
Max	8.6	

Note: 1 ¢ = 1/100 $US

3.9.4 Thefactors that alter the cost envelope are usage of air or enriched oxygen for injection, the thickness of the coal seam, and the depth of drilling. The latter two factors determine the number of wells that need to be drilled and their required length. In case CCS is planned to be incorporated, Oxygen-blown gasification could be a prudent option.

3.9.5 According to a recent media report from UK quoting an EC funded study, the estimated cost of electricity could be around £ 44/ MWh (~ Rs

4/ kWh); this is comparable to the current band of electricity prices in most of the European countries.*(www.uk.reuters.com, Oct 2013)*

3.10 Recent developments:

3.10.1 US: As per a report from the US NETL [125], though research into the UCG arena had remained mostly in the private sector, (barring the state of Indiana), a Colorado-based company, (Luca Technologies), recently announced research into UCG using microorganisms to break down coal into methane and other gases, rather than heat from combustion.

3.10.2 Australia: As per the report from US NETL quoted above, despite suffering serious environmental damages in two projects in the Queensland province, wider commercial applications of UCG are still being considered. A point specifically noted in this connection is that in both the projects which created environmental damage, the siting was at relatively shallow depth.

3.10.3 Further, a recent, (March 2014), Central Queensland University research paper [126] has come out with a proposition that deep seated abandoned coal seam gas, (CBM), blocks have the potential to develop UCG gas . The main argument put forth is that these deep seated mines while extracting the coal from the abandoned CSG blocks can also use these locations for storing the CO2 captured from the UCG process since typical abandoned CSG blocks are below the threshold depth required for storing CO_2 in supercritical conditions.

3.10.4 UK: In UK, Five Quarter Energy Holding Ltd. has developed a patented technique titled 'Deep Gas Winning' for extraction of gas from coal located deep offshore in the north sea. As per their claim published recently in Natural gas Europe as a news item, (www.naturalgaseurope.com, Mar 2014), the process is unique in that it does not involve hydraulic fracking and its consequent environmental impacts. Further, they intend to make composite products for catering to both the chemical and the electricity industries, effectively making it carbon neutral. The project is expected to take about 3- 4 years to start commercial operations.
However, no details about the technology are available in the public domain.

3.10.5 EU: Under a research project funded by the European Commission[123], a 2 ½ year long study was undertaken for evaluating the potential of deep lying coal(>1200m) for the twin objectives of economic energy extraction as well as using the voids for storage of CO_2 generated from the project. The study was carried out keeping the characteristics of the Dobrudzha Coal Deposit, (DCD), of Bulgaria, with coal seams lying between 1200 to 1800 m, as the template. The following major points emerged from the study:
i). The thickness of the coal seam has relatively more impact on the lifecycle cost-economy of the project.

ii). A minimum distance of 150 m should be maintained between the gasification channel and nearby geological faults in order to avert potential gas or CO_2 leakage.
iii). Cost of Electricity
- UCG without CCS : € 25 - 47/ MWh
- UCG with CCS : € 53 - 76/ MWh

The lower and upper ranges correspond to higher and lower seam thicknesses respectively.

Apart from this, Poland is currently undertaking a national project to test a UCG pilot in the Upper Silesian Basin and to produce an industrial plant design by 2015.
Poland is also co-ordinating the HUGE2, (Hydrogen Underground Gasification Europe 2,) project [128], supported by the EU Research Fund for Coal and Steel. This project includes a gasification test at the Polish experimental Barbara mine, (now complete), further investigations into hydrogen production from UCG, safety studies and research on control of ground water contamination by reactive barriers.

3.10.6 South Africa: An EIA report prepared, (Feb 2014), for A 60 MW power project near Theunissen in the Free State Province of SA is currently under implementation. The report brings out some salient aspects of the projects as follows:

i). Coal bearing area	: 150 hectare
ii). Reserves	:5 Million Tons
iii). Life of the project	: 5 years
iv). Estimated area of gasification	: 950 x 500 m.

3.11 UCG : Prospects as a medium / long term energy source:

3.11.1 As on date, no modern UCG plants have been in operation. However, a number of projects are in various stages of implementation with China leading at the front.

3.11.2 Though there have been environmental related setbacks in some of the projects across the globe, the stake-holders in the energy sector are still positive about the long term attractiveness of UCG as a potential source of scalable energy with moderate risks to the environment.

3.11.3 The setbacks in two projects have forced policy makers to have an all-encompassing frame-work for a sustainable operation of UCG with minimum damage to the environment.

3.11.4 As per the recent, (Dec 2013), release from the IEA Clean coal centre (www.iea-coal.org), commercialisation of UCG requires more work on demand, technology, finance, environmental issues and government regulation.

3.11.5 The report goes on to state that several private companies are in the process of exploring the development of UCG in the Far East, including Gazprom,Mitsui & Co and Linc Energy. Besides, the Russian

Government is funding several UCG research projects including development of underground gasifiers with heat recovery, ranking of coal deposits for UCG and creation of new educational programmes for training of engineering and research.

3.12 UCG Vs CBM :

3.12.1 This is another important aspect which has attracted the attention of the policy makers. As per the current classification, UCG falls under the category of 'Mineral' whereas CBM falls under 'petroleum', the latter attracting more stringent regulations in respect of safety.

3.12.2 In fact, it is reported that perhaps inferior regulations associated with the minerals may have contributed to the environmental damage caused by the two UCG projects in Queensland[124].

3.12.3 The IEA report cited above also specifically brings this aspect out. It mentions that International legislation for UCG is complex and the dominant view favours UCG to be considered under mineral and not petroleum legislation. It goes on to state that the issue of consistent regulations and legislation for UCG is still an ongoing challenge and further work on best practice guidelines in UCG would assist regulators in making informed decisions.

3.12.4 However, South Africa appears to have taken some lead in this direction as per a news item recently, (April 2014), published in the Mining Weekly (www.miningweekly.com) It reports an amended regulation for UCG, whereby it is proposed to consider the UCG extraction under mineral regulation whereas the downstream usage of gas under regulation for Energy, (implying petroleum products).

3.13 Indian scenario

3.13.1 In line with global recognition of UCG as one of the potential cost-effective sources of energy, effort has been going on in India also to explore its potential.

3.13.2 Though pioneering work on UCG in India commenced more than 30 years ago, it was only in the recent past that it was recognised as a frontline source of energy for the country.

3.13.3 In 2009, the MoC issued guidelines for both allocation of blocks and mining. [52]

3.13.4 The main findings of a CMPDI study (2012) on this are discussed below.

Around 88 BT of coal lies between 300 m and 1200 m, which (with today's technology) - cannot be economically mined. Similarly about 27 BT of lignite lies below a depth of 150m, which is again beyond the scope of existing mining.

3.13.5 The report does not project any cost-economy of UCG in India [53]

3.13.6 Institutes like CMRI have also conducted pilot studies on the subject. However, the basis of CMRI's cost projection for electricity,(<1.5 cents/ kWh or less than Re 1/kWh), is not clear [54]

Recently, NIT Rourkela has also published a paper on the potential for UCG in India.[55]

3.13.7 The government of India had started taking steps to auction five lignite blocks and two coal blocks with aggregate estimated reserves of 950.5 million tonnes in the beginning of this year; however, it has still not moved forward. Recent,(mid –October), reports suggest that the auction would commence only after a national policy on coal gasification is firmed up.

3.13.8 As regards regulations in India, as of now, the UCG is still under the purview of the Ministry of Coal and hence by default, the rules governing minerals might apply for its regulation. However, keeping in view the pooled international experiences so far, it is quite possible that rules may be tweaked in order to find a balance between the interests of different stake-holders including the public at large.

3.14 Cost-Economy for Indian UCG:

3.14.1 At the outset, the main issue will be bringing out the coal gas from underground. Once coal gas is brought out, it can be piped to potential usage points.

3.14.2 So the main differentiating factor for the UCG will be will be to estimate the cost of UCG gas at the well-head.

3.14.3 Again, keeping in view that this will be a first of a kind technology for India, the initial project costs are expected to be high.

3.14.4 Further, the cost of UCG will be primarily Opex oriented being akin to a mining operation.

3.14.5 The plant model envisaged for a UCG based power plant in India is as follows:

Coal seam depth : ~ 200 - 300 m
Seam thickness: ~ 3- 5 m.
Plant capacity : 3000 MW within 50 km of the mine; transportation of product gas by pipeline.

Capex for the UCG	: Rs 100 000 Million
Capex for Power plant	: Rs 120000 M
Annual Opex for Power plant	: Rs 9000 M
Annual Opex for mine	: Rs 34 000 M
Configuration	: 6 gas turbines of H class + 3 steam turbines

Cost of generation after stabilisation: Rs 3 - 4 / kWh

3.15 Forecast of the technology:

3.15.1 Based on the potential and estimates, prima facie, there are good prospects for UCG in India.

3.15.2 However, by far the biggest concern will be identifying the blocks with a good degree of accuracy about the quality and quantity of coal as well as addressing the environmental concerns.

3.15.3 The risks of exploratory drilling costing significant Capex and Opex may have to be undertaken for each block identified, which has its own associated time and financial risks.

4.0 OXY-FUEL COMBUSTION

4.1 Introduction:

4.1.1 Oxy-fuel combustion essentially uses(virtually) pure oxygen for combustion in a boiler in place of air used in conventional boilers.

4.1.2 Oxy-fuel combustion is accomplished by employing an Air Separation Unit (ASU) wherein Nitrogen is removed and the generated oxygen is sent to the boiler.

4.1.3 The advent of oxy-fuel combustion was prompted by the need for cost – effective capture of CO_2.

4.1.4 The primary advantages of oxy-fuel combustion are:

i). NOx formation can be reduced.

ii). Since the net flue gas mass is reduced significantly, it is easy to capture CO_2.

iii).The cost of CO_2 capture with Oxy-fuel combustion retrofit for existing units can cut down the cost of CO_2 capture by one third.

4.2 Basic description:

4.2.1 An oxy-fuel combustion system primarily resembles conventional thermal units barring the addition of the air separation unit. An air separation unit separates nitrogen from the air and the preheated oxidant is sent to the furnace. However, since the oxidant reaching the boiler will have high concentration of oxygen, in order to have a stable combustion, part of the flue gas downstream of the gas cleaning system is recycled back to the furnace.

4.2.2 Typically, about 80% flue gas is recycled so as to produce stable combustion.

4.2.3 Since the concentration of SO2/ SO3 goes up in the flue gas in view of the lower mass, normally FGD will be required for mitigating the cold end corrosion.[56]

4.3 Process variants:

4.3.1 The configuration of a Oxy-fuel combustion depends on a number of process variants as follows:

i). Purpose –built (Greenfield) or retrofit.

ii). Optimum level (concentration) of Oxygen in oxidant gas

iii). Desired properties of CO_2 in flue gas

iv). Degree of clean up (NOx, SOx and mercury) required.

v). partial or full sequestration of CO_2.

4.4 Status of Technology As on Date/ Challenges:

4.4.1 Based on the published literature, Oxy-fuel combustion is still at an early stage with a representative sized unit yet to be demonstrated. A number of OEMs have carried out pilot studies aiming for demonstration units.

4.4.2 Following are the major barriers which are holding the technology back from developing into a commercially viable power generation mode[57].

4.4.3 Air separation unit is Capex and Opex intensive.

4.4.4 Flame stability and ignition is still a concern entailing significant quantities of flue gas (~80%) recycling; this also imposes an energy tax on the unit [58]

4.4.5 Sealing against air ingress is also an area of concern with 100% sealing not being feasible.

4.4.6 More components imply lower reliability.

4.5 Recent Advancements

4.5.1 One of the advancements made is migration into CFB for oxy-fuel combustion. There are certain specific advantages compared to PF technology:

i).Oxy-fuel CFBC requires significantly less recycled flue gas to control boiler temperature, due to the re-circulating solids that effectively act as a heat moderator. This permits the use of a much higher oxygen concentration in the combustor, and allows the economics of oxy-fuel CFBC to be significantly improved over PF firing through a reduction of the size of the CFBC boiler island by as much as 50%.

ii). Since the bulk of the heat transfer is accomplished with solids (called 'inerts' in CFB parlance) oxy-fuel CFBC does not require sophisticated burner systems.

iii). Further, the technology's twin inherent abilities- for in-situ SOx removal and far lower NOx generation are other attractions.

4.6 Overseas experience

4.6.1 Published literature lists out the following projects at different stages of maturity.

4.6.2 US : FutureGen Alliance: A collaborative project by the US Department of Energy, State of Illinois, Ameren Energy Resources, Babcock&Wilcox and American Air Liquide. It is a 200 MW retrofit project for power generation cum carbon capture, scheduled to be commissioned in 2017.

4.6.3 Callide, Australia: A 30 MWTh project for CO_2 capture, jointly financed by a number of industry- institutional collaborations is under demonstration.

4.6.4 Spain: Canmet energy is currently conducting a joint research project for a 30 MWTh oxy-fuel CFB technology demonstration plant in Ciuden, in collaboration with the North American and Finnish arms of Foster Wheeler. The ultimate goal of the project is to demonstrate a carbon capture and storage (CCS) facility fully integrated in an approximately 300 MWe power plant. Other partners in this project include Vattenfall of Sweden, and Endesa Generación S.A. (ENDESA) and La Fundación Ciudad de la Energía (CIUDEN) of Spain.

4.7 Update on Indian initiatives:

4.7.1 In India also, some pilot work appears to be ongoing under collaboration between BHEL and NIT Trichy towards building a demonstration project.

4.8 Economic Performance:

4.8.1 As of now, only a few pilot plants are operating across the globe.

4.8.2 However, a number of studies have been undertaken for simulating the performance of oxy-fuel combustion for large size units.

4.8.3 According to a study[59] carried out jointly by MIT(US) and ENEL (Italy), considering two cases have projected the following performance figures:

TABLE 2.15: COMPARISON BETWEEN ATMOSPHERIC AND PRESSURISEDOXY-FUEL COMBUSTION

Sl. No.	Parameter	Atmospheric Oxy-fuel combustion	Pressurised Oxy-fuel combustion
1	Gross Power	404.5	388
2	Aux. Power	97 (24%)	86.9 (22.3%)
3	Gross Efficiency , %	46.2	44.2
4	Net efficiency	35	34.3

4.8.4 It can be observed that though gross efficiency is higher than even USC units, the net efficiency is close to mid-size subcritical units. This is because of the significant aux power consumption for both the Air separation unit (ASU) and the flue gas recirculation(FGR) fan

4.8.5 Since there is no operational experience with even medium size oxy-fuel plants, no representative data regarding the Capex or Opex is available.

4.8.6 However, convergence of several studies indicates that the oxy-fuel combustion without carbon capture will be more expensive. Any representative figures however may be available only after sustained operation of a medium to large scale demonstration plant.

4.8.7 Start up time in cold condition is projected to be about 40 - 50 hours in view of prolonged time required for ASU start- up.

4.9 Environmental performance:

4.9.1 In view of the reduced volume under oxy-fuel firing, the concentration of NOx and SOx in flue gases will be higher than pulverised fuel firing; however, on a unit fuel input basis, these will be lower than the latter.

4.9.2 Of particular mention is NOx which would be about a third compared to PF combustion.

4.9.3 Unburnt carbon and SOx also are projected to be lower [60].

4.9.4 Even mercury emission is reportedly only 50%; however, the mechanism by which this is achieved is not clear [61].

4.10 Flexibility in operation

4.10.1 Since ASU is an integral part of the Oxy-fuel combustion, the response of the technology will be almost identical to IGCC. The minimum load and ramp up rate are 40- 50 % and 1- 3%/ minute respectively.

4.11 Barriers in the way of development

4.11.1 The primary barrier against development of oxy-fuel combustion is the economics on multiple fronts: higher Capex and lower net efficiency.

4.11.2 As a technology, oxy-fuel combustion had been conceived for facilitating carbon capture in view of the far higher concentration of CO_2 in flue gas, which facilitates CO_2 capture more economically than other competing technologies.

4.11.3 Hence for oxy-fuel technology to get populated as a frontier power generation mode, it is a pre-requisite that it is integrated with CCS.

4.11.4 On the technological front, the other issues are maturity required in the combustion process, especially with flue gas recirculation.

4.12 Prospects of oxy-fuel Combustion for India

4.12.1 At the outset, the technology is in an incipient stage even in advanced economies.

4.12.2 Though a number of research projects are ongoing across the globe for making oxy-fuel combustion as one of the frontier technologies, since the economics of this technology is closely related to the deployment of CCS, it can be inferred that the further growth of oxy-fuel combustion will be concomitant with that of CCS.

4.12.3 Further, one of issues specific to Indian condition is that since oxy-fuel combustion needs significant flue gas recirculation, the extreme dust load in Indian flue gases can act as an additional constraint.

4.12.4 In India, any significant movement on adopting this technology is foreseen only after the technology matures in advanced economies.

5.0 CARBON CAPTURE AND STORAGE

5.1 Introduction:

5.1.1 The technologies of Carbon capture, when applied to fossil fuel based power plants can be broadly divided into the following three categories:

- Pre-Combustion Capture
- Post- Combustion Capture
- Oxy- fuel combustion capture

5.1.2 Pre-combustion capture involves removing pollutants and CO_2 in the upstream treatment of fossil fuels prior to their combustion for the recovery of heat or the production of electric power or hydrogen. Based on the information available in the public domain, these technologies are at or near the commercial demonstration stage.

5.1.3 In Post-combustion systems, CO_2 is separated from the flue gas stream generated from PF fired power plant boilers. In this approach, CO_2 is separated from nitrogen (N2), which forms bulk of the flue gas.

5.1.4 Oxy-combustion separates O2 from the N2 in air prior to coal combustion. In this case, the concentration of $CO_2$is much higher since N2 has already been separated beforehand, and this considerably reduces storage volumes.

5.1.5 Carbon capture, after its importance was flagged by climate scientists, has attracted substantial attention the world over since the signing of the Kyoto protocol. As of now, the technology, though essential for mitigating climate changes has been found to be prohibitively expensive to implement especially for large sized power plants. Hence, global organisations have been pursuing relentlessly for new technologies which can bring down the cost of capture.

5.2 Pre-combustion capture

5.2.1 To enable pre-combustion capture, the syngas generated from the gasification process is further processed in a water-gas shift(WGS) reactor, which converts CO into CO_2 while producing additional H2, thus increasing the CO_2 and H2 concentrations.

5.2.2 An acid gas removal system is then used to separate the CO_2 from the H2. Because CO_2 is present at much higher concentrations in syngas (post- WGS reaction) than in flue gas, and because the syngas is at higher pressure, CO_2 capture should be easier and less expensive for pre-combustion capture than for post-combustion capture.

5.2.3 Advantages and challenges of pre-combustion capture:

TABLE 2.16: PRE-COMBUSTION CO_2 CAPTURE: ADVANTAGES AND CHALLENGES

Sl. No	Advantages	Challenges
1	CO_2 separation via solvent absorption is already demonstrated. The exhaust gas comes at elevated pressures and high CO_2concentrations will significantly reduce capture costs	Must cool down synthesis gas for CO_2 capture, then heat it back up again and re-humidify for firing to turbine
2	For a 90% capture, a benchmark for comparing the CCS technologies, Pre combustion capture of the CO_2 under pressure incurs lower energy penalty (~20%) than the current PCC technology	A portion of H2 may be lost with the CO_2
3	As gas turbine efficiency keeps improving, the overall efficiency of pre-combustion capture is expected to improve concurrently	It requires major modifications to existing plants for retrofit

5.2.4 Methods of Pre-combustion capture:

There are two major generic types of 'Acid gas' (i.e., CO_2, H2S, COS) removal (AGR) solvents – chemical and physical.

i). Chemical Absorbents:

Chemical absorbents react with the acid gases and require heat to reverse the reaction and release the acid gases. While these processes generally have lower Capex for AGR than physical solvents, the flip side is that they use higher amounts of steam-heat for solvent regeneration.

ii). Physical Absorbents

Physical absorbents (e.g., Selexol, Rectisol) dissolve acid gases preferentially with increasing pressure. The absorbed acid gases are released from the solvent when pressure is decreased and temperature is increased.

Significantly less steam-heat is required for solvent regeneration than with chemical solvents.

The Rectisol process, which uses chilled methanol, generally has a higher capital cost, but provides the most complete removal.

5.3 Post-combustion capture:

5.3.1 Flue gas from the boiler consists mostly of N2 and CO_2, with a trace of oxygen. The CO_2 capture process would be located downstream of the conventional pollutant controls like ESP. Chemical solvent based technologies currently used in industrial applications are being considered for this purpose. The conventionally employed chemical solvent process requires the extraction of a relatively large volume of low pressure steam from the power plant's steam header, which decreases the gross electrical

generation of the plant. The steam is required for release of the captured CO_2 and regeneration of the solvent.
The advantages and challenges associated with post-combustion capture are tabulated below.

TABLE 2.17: POST-COMBUSTION CO_2 CAPTURE: ADVANTAGES AND CHALLENGES

Sl. No	Advantages	Challenges
1	Inherently suited for retrofit to existing plants; virtually no downtime lost	Significant amount of energy (in the form of heat) required to reverse chemical reaction de-rates power plant. Typically 30 % power and 10- 12% efficiency penalty.
2	Being an 'end-of-pipe' process, flexibility in switching between capture and no capture possible.	Water use is increased significantly with the addition of PCC particularly for water cooled plants.
3	The method renders itself 'learning by doing'.	Chemical stability/ corrosion still a challenge.

5.3.2 Methods of Post- combustion capture: the following are the available technologies for post-combustion capture:

- Absorption
- Adsorption
- Membrane technology Cryogenics

5.3.3 Of these, the most common application for large capacity coal fired plants is membrane technology.

5.4 Oxy-fuel combustion capture:

5.4.1 In oxy-combustion, coal is burned with relatively pure oxygen diluted with recycled CO_2or CO_2/ steam mixture. The primary products of combustion are water and CO_2. Due to nitrogen removal from air, oxy-combustion produces about 75% less combustion volume compared to conventional combustion. Since the product consists of about 70% CO_2, it is easier to remove the contaminant also.
However, there are a number of challenges for the oxy-combustion technology:
i).Using oxygen in place of air escalates the heat flux in the boiler and its attendant implications on metallurgy etc.
ii).Multi-fold increase in acid gas concentration also has its implications in the furnace and heat transfer tubes.
iii). Prevention of air-in-leakage in the boiler is another challenge.

5.5 Recent Advances in Capture:

5.5.1 Recognising the basic challenge of reducing the overall cost of CCS, a number of research projects have been going on across the world.

5.5.2 US DOE has identified the following areas as key challenges in the realisation of viable deployment of CCS[62]:

↓

Sl No.	Parameters
1	Scale up
2	Parasite power and steam reduction

Sl No.	Parameters
3	Energy integration with power plant
4	Mechanical integration
5	Management of contaminants
6	Water usage.
7	Waste management
8	Overall cost

5.5.3 Apart from improvements in current technology, two further stages in the viable deployment of CCS are the following:

- ➢ Second generation capture technologies which are in the R&D stage at present.
- ➢ Transformational technologies: Technologies, including technology components, that are in the early stage of development or are at the conceptual stage but have the potential for improvements in cost and performance beyond those expected from 2nd-Generation technologies.

↓

According to very recent media reports, a breakthrough in Chemical looping combustion has been achieved in July 2013 by a US university. The primary information available states that it uses a counter current moving bed reducer and oxidiser along with an iron based composite oxygen carrier.
The unit converts coal syngas to carbon free energy carrier and in the process facilitates simultaneous generation of electricity and hydrogen.
According to the press, their demonstration project is the largest scale up of chemical looping gasification technology for gasification from hydrogen generation from coal and hence holds significant potential for low carbon energy generation (*www. eem.jacksonkelly.com, July 2013*)

5.5.4 A few of the other areas of current focus of research are as follows:
i). Adsorption with metal organic frame works.
ii).Low temperature separation processes such as :
- Cascaded refrigeration systems to cool the flue gas.
- Cryogenic CO_2 capture (CCC) process.
- Condensed contaminant centrifugal separation process

5.6 CO_2Transport:

5.6.1 The following are typical modes of transport employed for the CO_2 captured from plants:

- ➢ Pipeline
- ➢ Ship

5.6.2 Based on several studies, it is reported that for off-shore storage, pipeline transport may be cheaper for distances up to 200 km, beyond which shipping transport may be cost-economic.

5.7 Storage of CO_2 and monitoring

5.7.1 The potential sites for the storage of captured CO_2 are :
- Underground or abandoned mines
- Depleted oil and gas reserves.
- Saline aquifers
- Geological formations

5.8 Status of CCS Overseas:

5.8.1 A number of media reports have been coming out on the status of the CCS projects worldwide, across planning to operation phases during the last several months.

5.8.2 One specific area was the slow down or in some cases, complete halt to some projects in North America(mainly US and Canada), as a sequel to the shift away from coal based plants in view of the abundant availability of gas.

5.8.3 Even in Norway, which has a significant carbon tax, one major project at Mongstad refinery was cancelled after cost overruns and delays. The project had aimed to capture exhaust gases from a residue catalytic cracker and 280 MWe natural gas fired CCHP. The project had incurred Norwegian Kroner 1.2b (~ €160 million) when it was cancelled in Sept 2013.[63]

5.8.4 The recent (Oct 2013) report of the global CCS institute has captured the current status of worldwide projects[64]. The summary is presented below:

5.8.5 Against a total 75 large scale projects worldwide reported in 2012, only 65 are currently in progress at various stages. During the past year, five projects were cancelled, one scaled down and seven put on hold for various reasons, including investment re-prioritisation and insufficient financing and legislative support.

5.8.6 Based on independent reports, the 're-prioritisation' which the report states suggests carbon prices lower than the expected return from CO_2 use in EOR etc.

5.8.7 The report also gives some positive news like addition of 3 new projects across different countries.

5.8.8 However, none of the four projects which started operations are related to CO_2 capture from power projects, though four power projects based CCS are expected to reach financial closure soon.

5.8.9 Another significant aspect the report brings out is there is an increasing population of the CCS projects in China. But here again, based on independent reports, China has a good number of projects where the CO_2 captured can be used for EOR.

5.8.10 However, in general, even in Europe which, as a continent has been pioneering low carbon movement for the past several years, no definite momentum appears to have come about.

5.8.11 In fact, going by the myriad news reports emanating from various sources across several countries in Europe, it appears that there is a difference of opinion on how to take the low carbon movement forward between policy makers and implementing agencies.

5.8.12 A recent example from Germany appears to corroborate this divide: the 360 MW (Net) IGCC based Pre-combustion CCS Project for BASF, RWE Power and the Linde Group near Cologne, Germany,(2.3 MTPA CO_2 removal) has recently been cancelled since the requisite legislation from German lawmakers could not be put in place.[65]

5.8.13 As per a study by European Commission[66], the following sequence of events have led to the slowdown of activity in Europe in pursuing carbon reduction:

i). With shale gas discovery in the US, the coal consumption in the US has been slowly coming down with the result that more coal was getting exported, predominantly to Europe and as a sequel to market dynamics, the prices also have been falling (on *checking the data, it has been found that on an average, the export price of US coal to Europe has fallen between 15 % 30 % between 2012 and 2013*). This obviously led to cheaper coal in EU zone and consequently coal consumption has been going up.

ii) As a consequence, attractiveness of migration to a low carbon regime subsided in Europe in general.

iii). The avoided cost of CO_2 have been still high in EU, with 40 and 80 Euro per TCO_2 for coal and gas respectively.

iv). The carbon prices in Europe has been falling from 30 euro in 2008 to 8 euro in 2012.

v). Unlike US, there are very few EOR projects in Europe for overall cost leverage of CO2 capture.

vi). At member state level, across the Euro region, financial and political circumstances are found to vary substantially.

The summary of the Commission's finding was that with the given economic parameters driving the electricity industry, the CCS projects would not move forward without firm policy action.

5.8.14 The detailed response sent by Eurelectric, the body representing Utility electricity industry in Europe to the EU Commissions' consultative paper (circulated in March 2013) also appear to echo the Commission's reasoning about the Utility Industry's position.[67]

5.8.15 In fact, by far the most significant point flagged from Eurelectric's response is their apprehension about the potential mid-way shift in the operational pattern of CCS fitted utilities in a power system regime with an ever increasing share of renewables.

5.8.16 Their suggestion for CCS to succeed are

- To show case CCS as part of the solution for low carbon regime
- Allow thermal units to co-exist with nuclear and RE
- Establish infrastructure for transport and storage
- Engage the public.

5.8.17 Other reports suggest country specific interests for the lull in CCS:

- Germany appears to favour investing in RE instead of cost-intensive CCS.
- Poland has huge coal resources

5.8.18 In respect of the US, the EPA has come out with new environmental draft regulation in Sept 2013 which has effectively made it impossible to build coal based conventional units in the US.

5.8.19 As per their discussion paper, full capture of CO_2 will be outside the range of comparable generation and therefore they are envisaging technologies with partial capture of CO_2.

5.8.20 In the EPA's view, many CCs projects have been progressing in the US and they are seeing apparent viability for CCS.

5.8.21 It however, needs to be mentioned that in the US, a number of CCS projects are using the captured CO_2 for downstream use like EOR.

5.8.22 The reasons for China undertaking a number of CCS projects are – like those in the US - because they are finding downstream use of CO_2 captured like EOR.

5.9 Cost –Economics:

5.9.1 The cost of CCS has been estimated by a number of agencies from across the globe. Two latest estimates (2013) are one by US EIA (DOE) and another from Europe (Germany). The salient figures are tabulated below:

TABLE 2.18: ESTIMATE OF CCS COST ACROSS THE GLOBE

Sl. No.	Description	US DOE (EIA)	USDOE (NETL)	Germany (Europe)	China	Costs for Europe are converted figures from Euro (1€=1.35$)
1	PC w/ o CCS	NF	2000	NF	Cost generally 60 % lower than European cost as per one IEA based information.	
2	PC with CCs	5100	3600	3400- 4500		
3	IGCC w/o CCS	3700	2500	NF		
4	IGCC with CCS	NF	3600	3000- 5000		
5	CCGT w/ o CCS	1000	720	NF		
6	CCGT with CCS	2000	1500	1500- 2000		

Notes: 1.All figures in $US; NF : Not furnished

2. Cost for Europe based on *Current and prospective costs of electricity, DIW 2013.*

5.9.2 In US, for Kemper county 582 MW (with 65% CO_2 capture) the originally estimated cost of $2.88 billion got revised upwards twice as on date though construction is yet to be completed. Right now, it stands at $4.02 billion or $6900/ kW. On a back of the envelope calculation taking 7% as the cost of capital (for developed economies) the cost of CO_2 capture works out to be in the vicinity of ~ $ 75 / T CO_2.

5.9.3 The above tables and data shows as of now, only an envelope of cost region can be established. One of the reasons is that since no sizable capacity CCS has been operational, it is not possible to predict the costs with any degree of accuracy, even while allowing some variation between different processes (like pre and post- combustion).

5.10 Indian scenario:

5.10.1 India has been taking first steps in exploring the feasibility of carbon sequestration, primarily under the ambit of DST which has commissioned a number of projects in different academic institutions.

5.10.2 No information is available whether any positive breakthroughs have been achieved out of such ventures.

5.10.3 The closest attempt made about estimation of possible cost for CCS is considering the Mundra UMPP, by TERI prepared for global CCS institute, titled 'India CCS scoping study' in 2013[68]. The salient figures from this report are reproduced below:

TABLE 2.19: CCS COST ESTIMATE FOR INDIA

SL No.	DESCRIPTION	PLANT CONFIGURATION	
1	Base Plant configuration w/o CCS	5 x 800 MW	6 x 660 MW
2	Plant Conf required for identical net generation with CCS	6 x 800 MW	7 x 660 MW
3	Net output w/o CCS, MW	3930	3805
4	Net output with CCS, MW	3720	3755
5	Base plant Net HR , kCal/ kWh	2150	2200
6	Net Plant HR with Capture, kCal/kWh	2860	3160

SL No.	DESCRIPTION	PLANT CONFIGURATION	
7	Amount of CO2 to be captured, MTPA	34	32.8
8	LCOE w/o CCS , Rs /kWh	3.73	3.31
9	LCOE with CCS, Rs / kWh	5.48	4.87
10	Escalation in LCOE	47%	47%

5.10.4 Though in general, the methodology adopted and base input figures considered by TERI appears to be logical, a few points are worth putting down:
i). Basic Capex for CCS: A look at the table furnished earlier reveals the least differential cost for CCS is $1600/ kW; TERI's data is based on 2011; as reported by US EPRI recently, the cost of FOAK IGCC plants is significantly higher than their estimate for subsequent plants.
ii). All cost calculations are based on an exchange rate of Rs 50 to the US dollar. That will also change now.

5.10.5 Though in general, the methodology adopted and base input figures considered by TERI appears to be logical, a few points worth putting down:

5.10.6 The net effect of the above will be the significant increase in both the base LCOE costs and the differential between LCOE's with and without capture.

1.1.1 India's transportation and storage facility: Based on several reports on this, it appears that a detailed estimate of the actual storage facility in India is yet to be made, perhaps because there was no significant motivation for this task. However, preliminary studies show that India's hinterland capacity for storage is fairly limited. Except north the eastern region, no other area has got CO_2 storage capacity equivalent for generation from a UMPP (~ 1GT for 35 years).

1.1.2 The only feasible locations reportedly available are in deep saline aquifers, with unknown environmental consequences and climate risks.

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Section III
Combined Heat and Power

1.0 INTRODUCTION

1.1 This section broadly attempts to cover the following areas:

- Co-generation (generation of power and Steam)
- Trigeneration (generation of power steam and cooling)
- Recovery of waste heat from process

2.0 COGENERATION:

2.1 Boiler Technology for Cogen Plants:

2.1.1 Since fuel plays a pivotal role in the conception of a solid fuel based cogen plant, the boiler technology is selected broadly keeping in view the likely availability of the fuel for the proposed cogen plant.

2.1.2 Normally, for a coal based unit without any co-firing envisaged, the proven technology is fluidised bed combustion. However, in the case of cogen applications, unlike CFBC technology employed for utility projects, BFBC is mostly selected by striking a balance between cost and efficiency. In the case of co-firing or fully biomass based projects, travelling grate technology is used.

2.2 Efficiency:

2.2.1 Solely from a technical standpoint, classical rules of efficiency cannot be applied in the case of cogen, since electrical energy and heat (steam) are two different levels of energy.

2.2.2 Normally efficiencies are expressed in terms of utilisation of the primary (fuel) energy. Cogen efficiency varies in proportion of heat (steam) to power for the particular project.
It has been found that industries like sugar production requires significant steam at low pressure which makes the bagasse based cogen one of the most efficient cogen systems.

2.2.3 However, it needs to be mentioned that many of the cogen plants built earlier had adopted a fairly low pressure/temperature thermodynamic cycle (typically in the vicinity of 40 bar/ 400 °C) giving low electrical efficiency. Though the overall efficiency is better in cogen mode, since many plants operate off-season generating only electrical power and feeding to the local electrical grid, fuel consumption during the off-season becomes very high with low pressure temperature cogen system.

2.3 Availability :

Reasons are manifold:

2.3.1 Equipment Design related:
Unlike large utility projects, the cogen boiler market is extremely competitive with a number of players and consequently is highly price sensitive; it has been reported that a lot of trade-off between reliable operations and cost happens virtually in all the projects, compromising the quality even at the design stage.
Typical cases are

- Designing with lower than optimum tube pitches

- Irrational placement of heat transfer surfaces for boilers firing high alkali metals/ chlorine bound fuels,
- Use of welded tubes instead of seamless tubes for high temperature/corrosive environment.

Compounding this, the degree of Owner surveillance from design to construction is fairly limited in many projects partly owing to inadequate skill sets available with the owner and partly due to the pressure on schedule.

It has been found that for many cogeneration projects; the plant performance demonstration test does not get conducted owing to various reasons, many of these extraneous.

2.3.2 Deviation from the recommended O&M procedure:

The prime reason for this is the fuel diversity applied arbitrarily to the boiler by the owner without consulting the OEM. Many times, the fuel identified at the inception of the project may not be available after a few years of operation, and in such circumstances, the owners are compelled to reach for the 'low hanging fruit' of firing whatever is available in the vicinity. Since high pressure high temperature boilers are sensitive to fuel chemistry, especially presence of chlorine and alkali metals (typically present in many biomass fuels), sustained use of these leads to forced outages.

Other reasons on this front include deviations from the recommended water chemistry, not following recommended ramp up rates during start up etc.

2.4 Environmental performance:

2.4.1 But for the overall efficiency and consequently marginally lower carbon footprint, the environmental performance of most of the cogen plants has been less than satisfactory, in real terms. Again this has a lot of things to do with tight budgets under which typical cogen units are built and operated.

2.4.2 SOx Emission: Many cogen plants fire fuels with moderate to high sulphur content and incorporate sulphur capture mechanisms in the boiler; however, in practice, this is hardly operationalized because the cost of sorbent (limestone) happens to be significant in most plants.

2.4.3 SPM: Though nowadays, all cogen units are fitted with ESPs, not enough attention appears to be given to ensure the compatibility of the ESP design with the fuel characteristics. This assumes significance in view of the wide fuel diversity seen in many cogen applications. The main reason for this is that for small capacity applications, the cost of a rationally sized ESP could be comparable to the cost of the boiler itself and this act as a deterrent.

2.4.4 NOx: Generally with FBC, NOx is only marginal; however, with travelling grate boilers, NOx generation will be in the same range as pulverised technology.

2.5 Water requirements:

2.5.1 For a cogen plant, process water (typically DM quality) requirements will depend on the steam demand and the proportion of the condensate return from the process plant to the cogen unit.

2.5.2 The raw water required for the cooling circuit also depends on the amount of steam entering the condenser. However, set off against a large capacity utility turbo-generator, the cooling water required for a small size cogen unit will be about double.

2.6 Start up time:

2.6.1 Since most of the cogen units employ relatively small/ medium size boiler-turbine units, they are able to start up from cold condition to full power within 3 to 4 hours.

2.7 Parallel operation with electricity grid:

2.7.1 A number of cogen units are nowadays operating in parallel with local electricity grids without many hassles.

2.7.2 **Local manufacturing facility**:
In respect of cogeneration using fossil/biomass fuels, there are adequate local manufacturers for the entire fleet of cogen project equipment including boilers, turbine and control equipment. Further, in respect of steam turbines, a number of overseas companies are also operating in India. By and large, no issue has been reported on availability of spares.

2.8 Barriers for Adoption/ complete exploitation of Cogeneration potential:

2.8.1 Cogeneration planners and owners of the plants already in operation face a number of constraints in harnessing the potential in a sustained manner. The major constraints are discussed below.

2.8.2 Sustained availability of fuel: This is by far the biggest barrier in the growth of cogeneration projects. Biomass is the base of many cogen small and medium capacity (up to 15 MW) projects. However, except for projects with bagasse, cogen projects with other biomass fuel find it difficult to procure fuel at economic prices in a sustainable manner. Since there is no institutionalised procurement of biomass fuel at many places, the owner is subjected to the vagaries of the market forces prevailing from time to time in and around the plant location. In order to partially circumvent this situation, many adopt multiple fuels or co-firing with coal. This puts a lot of challenge in reliable operation of the boiler, which is the heart of the plant.

2.8.3 Techno-Economics: In places where the demand of power and steam are relatively low (say < 500 MWh and < 10000 Tons per annum), economy requires going for the simplest form of Cogeneration: a boiler fitted with a backpressure turbine-generator. The steam from the exhaust of the turbine is taken to the process along with the electricity generated from turbo-generator. However, since the variation in steam may not be synchronous with the demand variation of power, the system would not work trouble free unless:

- a) The unit is connected to grid and run in parallel.

Or

- b) An extraction-cum- condensing system is installed.

Neither option may be found to be economical since

- Adopting option a) would entail paying demand charges for the connected load, which may increase the cost.
- Adopting option b) would significantly increase the Cogen Capex.

2.8.4 In this context, a few general aspects related to cost economics are presented here.

The (thermodynamic) efficiency of small size turbines keeps going down with the size; the implication of this for very small sizes can significantly offset the primary benefits of co-generation E.g.: the overall enthalpy conversion efficiency of a 3 MW turbo-generator (taking into account mechanical efficiency, gearing efficiency and generator efficiency) working in cogen mode will be in the vicinity of 55- 60% against ~ 85 % for a larger size turbo-generator. Compounding this, the efficiency of the boilers firing biomass would be in the vicinity of 75 to 80% partly owing to fuel properties and partly to the economic design of boilers. Put together, the energy efficiency gets significantly reduced.

Compounding this will be the additional electrical power/ steam required for additional auxiliaries for a condensing system (condensing and cooling water circuits, vacuum generation etc).The net result is that unless the heat to power ratio is beyond a threshold, cogen may not have economic viability for application to smaller sizes.

2.8.5 Recent developments: A few recent developments in the cogen arena are described below.

2.8.6 Solar cogeneration: Many solar CSP units are adopting the cogen mode in order to improve the economics.

2.8.7 High concentration Solar Photovoltaic Thermal System (HCPVT): In a path breaking development, IBM has announced in collaboration with Airlight energy, ETH Zurich and the Interstate University of Applied Sciences Buchs NTV that they have commenced development of a technology that could harness the energy of 2,000 suns and provide fresh water and air conditioning in remote locations[69]. The new technology is to deploy a "micro-channel cooling system", in the PV chips, identical to the one used in their supercomputers to keep them cool enough to function. A prototype HCPVT is reportedly being tested in Switzerland. The system's by-products will also include desalinated water and cool air. No further details could be obtained.

3.0 TRIGENERATION:

3.1 Trigeneration is a concept which has caught attention during the past few years in the context of the quest for energy efficiency and security.

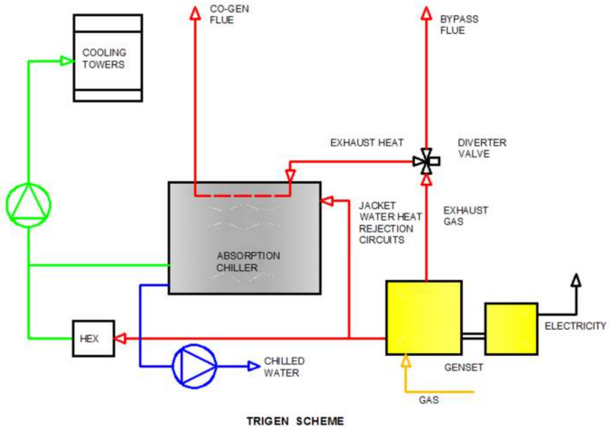

FIG 3.1 : SCHEMATIC OF TRIGENERATION SYSTEM

3.2 Trigeneration, as against cogeneration, caters to a different customer segment. Whereas cogeneration is dominated by biomass fuel or waste heat, Trigeneration is confined to gas turbines or engines. The concept was born out of exploring economically harnessing the waste heat for generation of chilled water for air conditioning, and the production of hot water, thus utilising up to 80% of the primary energy.

3.3 Target consumer base: Trigeneration will be most economical where simultaneous use of electric power, air conditioning and hot water is required like hospitals, hotels and malls.

3.4 Taking the report prepared by the energy efficiency export initiative of the German government[70] in 2010 as the base, and subsequent data gathered from various industry stake-holders, it is projected that the Heating, Ventilation and Air Conditioning (HVAC) market in India is poised to reach a capacity of 4.5 to 5.0 Million TR and at least 20% of this,i.e. a capacity in the vicinity of 1 million TR, is expected to be a chilled water based central system catering to hotels, hospitals, malls and other commercial / community centres. This is a potential target for trigen, especially keeping in view economies of scale associated with large capacity plants (2000 plus TR in most cases).

3.5 However, some cases like the Leela hotel in Gurgaon, a 1900 kW trigen installed is reportedly lying idle in view of the sharp increase in gas costs after 2010.

3.6 **Efficiency of Trigeneration:**

3.6.1 The energy balance of a typical gas engine of small capacity are as follows:

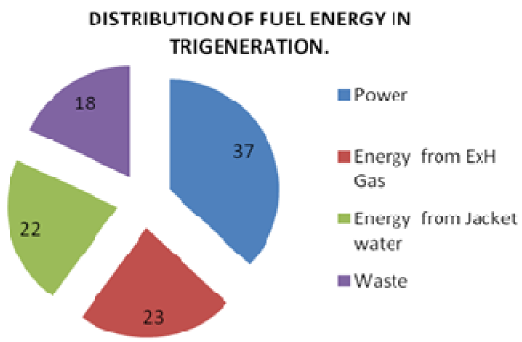

CHART 3.1: ENERGY DISTRIBUTION OF TRIGENERATION SYSTEM

3.6.2 From the above, it can be seen that while the conversion to electrical energy without trigen is <40%, trigen can lift the overall energy efficiency to above 80%.

3.7 Availability:

3.7.1 Since Trigeneration uses gas engines/ turbines and VAM, both being proven technologies, availability is assured.

3.8 Market:

3.8.1 There are a number of players in the trigen market, many of them suppliers/manufacturers of gas engines.

3.9 Economics :

3.9.1 Since only a few trigen projects have been installed, there is no clear information about the cost of a trigen installation; further, since trigen projects are customised for the specific project's energy split, no common benchmark can be found for economics of trigen projects. Normally, the basis for going ahead with trigen would be the payback period of Capex.

3.9.2 However, since in many cases, trigen is retrofit of gas engines with augmentation of VAM, cost of the VAM becomes a major component. Based on the available information, the VAM costs are in the vicinity of Rs 2500 - 4000 per TR for a medium capacity (200 to 500 TR). This is approximately, double the cost of a chilled water based direct chiller at current price levels.

3.10 Barriers for development of Trigeneration:

3.10.1 Despite the apparent attractions, trigen in India is facing roadblocks. The prime barriers are discussed below.

3.10.2 The main barrier for development of trigen in India is the availability of gas at an economical price. There are cases where trigen projects implemented have now become idle in view of the shooting up of gas prices during the past two years, escalating the operation cost. The non-availability of gas from the KG-6 basin has impacted, amongst many large gas based power projects, the potential growth of Trigeneration. Procuring gas from the open market now costs in the vicinity 10 - 11$/ MMBtu at which many potential Trigen projects will not be found to be viable, keeping in view alternatives available at today's cost levels.

3.10.3 A significant point in this connection is the status of Gas pipeline infra. Though a national gas pipeline grid was planned a few years ago, the progress on implementation has been slow so far. In fact, govt. has recently cancelled the contract for building 4 (four) gas pipelines of aggregate length of 2175 km from Kakinada in Andhra Pradesh to Howrah in West Bengal, Chennai and Tuticorin in Tamil Nadu and Mangalore in Karnataka. Another pipeline project in western India is still at tendering stage. Since the growth in the Trigeneration segment is going to be primarily in metros and Tier-I cities where large capacity hospitals, hotels and malls are expected to be built, it is necessary that adequate pipeline is built for reaching natural gas to these potential load centres. Many cities are yet to be connected by gas pipeline.

3.10.4 Other barriers are listed below:

- Lack of a clear definition of cogeneration or CHP
- Engines and turbines are still expensive from a `total ownership cost' perspective, especially for sets below 5 MW.
- Trigen does not have much fuel flexibility. While diesel can be used as alternative, it is more expensive than gas in the open market.
- At present, trigen projects are clubbed with cogen projects in respect of policy support.

4.0 WASTE HEAT RECOVERY FROM PROCESS.

4.1 There are also many industries where there is scope for harnessing cogeneration, as listed below:

Metal (Steel, Aluminium, zinc, copper)	Cement	Distillation	Glass	Refineries	Pulp and paper

4.2 The waste gases generated from some of these industries are of very high temperature as listed below.

TABLE 3.1: WASTE HEAT POTENTIAL FROM INDUSTRIAL PROCESSES

Sl. No.	Industry segment	Temperature
1	Steel heating furnace	900- 1000 °C
2	Cement Kiln (dry process)	600 – 700 °C
3	Aluminium refining	650 – 750 °C
4	Zinc refining	750 – 1100 °C
5	Copper reverberatory furnace	900 - 1100

4.3 The collective potential of these is estimated to be in the vicinity of 500 MW

4.4 Current status:

4.4.1 Waste heat recovery units have been installed in some of the factories across the industry segment listed above; however, compared to the potential, the installed capacities are fairly insignificant.

4.4.2 One major project worth mentioning is the 19 MW CPP installed by ESSAR steel at their Hazira works, based on the blast furnace gas from their steel factory.*(www.theindubusinessline.com)*

4.5 Economics:

4.5.1 Typically, the cost in respect of waste recovery systems is limited to Capex since Opex becomes incidental by way of providing auxiliary power and chemicals and lubricants. In most cases, the operational skill requirement is not demanding, the O&M staff can be sourced from the mother plant.

4.6 Barriers against accelerated development of waste heat recovery:

4.6.1 Since a large population of potential candidates for heat recovery are small sized plants, the primary barrier in development is lack of an integrated solution provider right from establishing economic feasibility.

4.6.2 In some cases, the source of heat comes with special challenges like fine dust which require heat recovery equipment capable of operating trouble free, necessitating dependence on imported technology, with its attendant hassles – cost, spares and service availability.

4.6.3 In the context, it needs to be mentioned that typically in India, SME players are normally attracted to additional investment in plant and machinery on a first order outlook of payback period based on the existing cost of energy; in many cases, the projects are taken forward if the investment is seen to be paying back within a period in the vicinity of 5 years.

5.0 FORECAST FOR CHP AND WASTE HEAT RECOVERY IN INDIA:

5.1 In many ways, CHP and waste heat recovery are low hanging fruits in enhancing the energy efficiency and given the right support, they have the potential to contribute towards economic generation of energy.

5.2 One of the major barriers against development of cogeneration/ Trigeneration and waste heat recovery is that heat or steam cannot be exported economically beyond a certain distance. The only way to circumvent this is to plan the source and user industries in such a way that a composite cogeneration, or if feasible Trigeneration, can be built in and around the physical confines of the complex. On a practical standpoint, this option may be feasible only for new industrial clusters.

Section IV
Renovation & Modernisation and Life Extension

1.0 INTRODUCTION

1.1 The R&M program for existing thermal plants was conceived by policy makers with the following broad merits Vis- a Vis Greenfield projects:

- Shorter horizon for realisation owing to a significantly lower gestation period of 10- 12 months against 40 odd months for green field projects.
- Capex for R&M was estimated to be less than half the cost of the Greenfield projects.
- Whereas green field projects called for additional land, water sourcing, building transmission corridor etc., for existing plants, these were already in place.
- Further, based on the initial projections of performance indices for some projects, the R&M was expected to put the unit back to its near original performance by way of:
    - Heat Rate
    - Auxiliary power
    - PLF
    - Emission

1.2 However, a primary evaluation of the R&M execution for the 11th plan period shows a different picture, as can be seen for GSECL Ukai 1 & 2, extracted from the CAG's audit report of GSECL.

1.3

TABLE 4.1 : CASE STUDY OF R&M FOR GSECL UKAI

Sl. No.	Parameter	Predicted performance	Actual achieved	Remarks
1	Station heat rate	**2482**	**2848 ***	
2	Aux power	**9.2**	**10.85 ***	
3	PLF	**80**	**50.6**	Part of this huge gap is due to unforeseen delays
4	Schedule (months)	**17** for unit#1 **27** for Unit # 2	13 month Delay 11 month delay	
5	Loss in generation, MU due to delay.	-	2,230	345 MU **avoidable loss.**

* How these figures have been arrived at is not transparent from the report since, the CAG report also mentioned that no performance test was carried out post- R&M. **(Ref: CAG report on GSECL 2005- 2010)**

1.4 A primary dissection of the figures show:

↓

The heat rate and aux power figures achieved post-R&M leave a lot to be desired, making even the very purpose of undertaking the R&M project questionable. The significant delay coupled with excessive drop in PLF implies a substantial increase in the loss of capacity charge. Of course, In respect of PLF, understandably there were some delays transcending the control of the utility.

1.5 That this is not an isolated incident is evident from some recent developments in which one state utility has decided to jettison R&M and go for a replacement since they found the former too expensive.[71]

1.6 Further, though about 26 GW was planned to undergo R&M during the 12th plan, as per the recent report from CEA, only less than two-third could actually be achieved.

1.7 As per the recent report from CEA released in 2013, delay in supplies of equipment by the equipment manufacturer, lack of co-ordination between the contractor and sub-contractors, shortage of BoP suppliers and delays apart from finalization of R&M contract are cited as the reasons for delay.[72]

1.8 However, an independent research into the reasons, point out the following aspects:

1.8.1 After 2006, since a number of Greenfield projects, including the first Ultramega project, were moving fast from concept to execution stage, the focus of the OEMs and contractors started shifting to the former owing to the far improved earning potential coupled with lower hassles associated with greenfield projects (as against manoeuvring through the maze of brown-field activities typically associated with R&M projects). Since this phase prolonged for more than 4 years or so, it appears to have significantly affected the schedule of the R&M projects.

1.8.2 The other connected reason was the cost escalation which occurred in the BoP segment during the same period in view of a sudden shift in the demand-supply regime favourable to the vendors. It is necessary to keep in view that many R&M projects were awarded on an administered cost-discovery based on the RLA results of a particular project, with CEA acting as the arbiter between utility and EPC contractors. Hence, in some cases, with (already) closed budget, EPC contractors found it difficult to cope up with almost 100% escalation which occurred later in some BoP segments prolonging their internal procedural work with consequent delays.

2.0 BARRIERS AND CHALLENGES FACED BY STAKE-HOLDERS:

2.1 In the light of the sample projects listed above, it is worthwhile to analyse the basic issues related to the R&M for thermal projects in India, as follows.

2.2 From the experience of R&M for the last few years, it appears that a harmonious view by stake-holders of the R&M has not been happening, for some valid reasons from their individual perspectives.

2.3 At the outset, it needs to be mentioned that thermal power plant RLA study, the key input for the R&M decision making, calls for multi-disciplinary intellectual inputs and state-of-the art tools; hence normally, this task is carried out by the OEMs themselves without much oversight from utilities.

2.4 Further, in this context, it is also necessary to keep in view that since R&M applies to plants which have logged at least 20 years operations, the natural target plants are virtually under state control. Further, barring a few in the central sector, the entire fleet under reference relates to state sector utilities.

2.5 From the perspective of the utility, since the majority of them do not possess the requisite skill sets to assess the extent of R&M their own plant requires, they are compelled to go by the RLA study done by a third party, without a clear understanding of the feasibility of the R&M since it is a decision by policy makers. Having grown up in an environment of typical regulated state sector where power generation has been operated with a quasi-business model till recent times, the utilities are not culturally oriented to take business risk.

2.6 Compounding this is a typical state utility's financial position.

2.7 However, there have been instances when utilities attempted to apply due diligence.

> In one case, after going through the initial phase, when the price bid was opened, it was found that the price quoted by the bidders were way above the base estimate and on a further techno-economic analysis arranged through a management consultant, it was found that the cost-benefit projections were not attractive enough to undertake the R&M; eventually, the utility decided to go for replacement project[73]

2.8 The OEMs/ EPC contractor also views it with apprehension since – in most cases, they have to deliver within a closed budget handed out to them by the regulators without a fair clarity of the scope, risking the vagaries of the market.

> At least in two cases, the not so encouraging experience(in one case prolonged dispute between Contractor and utility) has resulted in cancellation of the R&M project for the remaining units[74]

2.9 As for lenders, having dealt with a financially bleeding sector and unable to assess the feasibility of the project by themselves, they are also apprehensive about taking a decision. Many of the R&M projects in India are implemented with aid from multi-lateral funding agencies.

3.0 SHIFTING PARADIGM

3.1 The initial phase of the R&M project activities had been planned with a thrust towards putting the unit back to its capacity; hardly any real attention has been given to the efficiency related parameters (HR, APC and SFC). However, mid-way through the 11th plan period (Aug 2009), CEA came out with an integrated approach on R&M [75]with three prime objectives of enhancing energy efficiency and plant optimisation along with capacity uprating, as outlined in the National perspective plan for R&M (2009). The basic shift has been from the hitherto 'generation maximization' to 'performance optimization and generation maximization'.

3.2 The primary rationale of this can be seen from the following chart showing the shift in the proportion of fixed and fuel costs of generation for a typical coal based power plant:

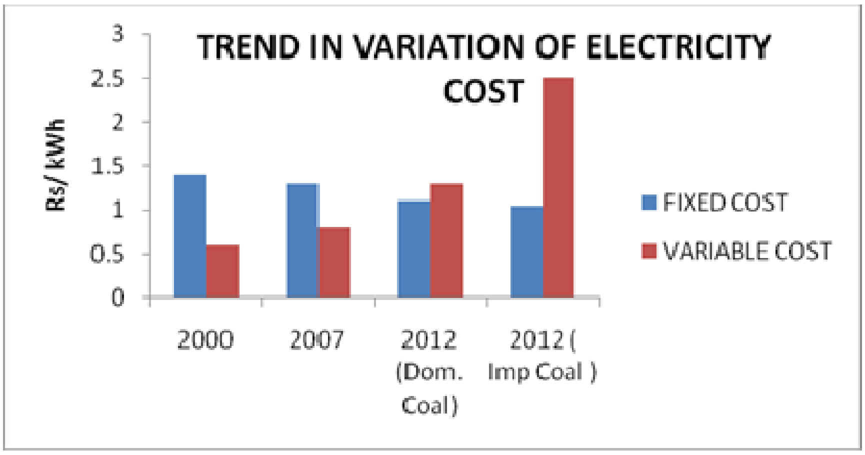

CHART 4.1 : TREND IN VARIATION OF COST OF ELECTRICITY IN INDIA

3.3 Further, as can be seen from the operating parameters of some of the typical plants around a couple of years ago, in some of the plants, there was significant degradation of all variable cost parameters, far lower than in well- run utilities:

TABLE 4.2 : OPERATING PARAMETERS FROM TYPICAL INDIAN POWER STATIONS

Plant#	Capacity	Average age	Average Station heat rate degradation (%)	Average specific fuel oil consumption	Remark
1	4 x 210	18	7.2	0.21	Data date 2010-2011;collected from regulatory filings
2	4 x 500	13	6	0.2	
3	5 x 210	12	6.3	0.2	
4	2 x 210	16	53	3.2	
5	3 x 210	15	13.5	1.3	
6	2 x250	15	2.2	0.13	

3.4 In the national plan brought by the CEA, certain guidelines have been given for carrying out the R&M measures, a few significant ones are listed below:

- LA study to be carried out for all units crossing 20 years of operational life.
- Compulsory retirement of units with heat rates consistently more than 20% from design values.
- Cost bandwidths for three categories- R&M, EE R&M and LE

4.0 SOME EXAMPLES OF R & M RESULTS FROM OVERSEAS PLANTS:

4.1 The results of some R&M programs carried out in overseas plants are tabulated below:

TABLE 4.3: R &M EXPERIENCE FROM SOME OVERSEAS PLANTS

Sl. No.	DESCRIPTION	COUNTRY	
		POLAND [76]	CHINA[77]
1	YEAR OF INSTALLATION	1982- 1988	1998
2	R&M performed	-	2010

Sl. No.	DESCRIPTION	COUNTRY	
		POLAND [76]	CHINA[77]
3	Major modifications	Replacement of significant part of SH Over-fire system Sealing system replacement for AH Replacement of HP and IP module and steam admission system Modernisation of gland system and a number of critical turbine auxiliaries.	Significant revamp of turbine blading system and gland sealing system along with overall modification of boiler system
4	Capacity improvement, MW	370 to 394	300 to 330
5	Heat rate improvement	2%	2446 to 2247 (~9%)

5.0 R&M FOR INDIAN POWER PLANTS- SOME GENERAL ASPECTS AND FOCUS AREAS:

5.1 At the outset, it appears that there is a compelling reason for raising the general apprehension about the ultimate aim of the LE (or R&M and LE) and its potential success in view of the following.

5.2 The bulk of the fleet is expected to be in the 210- 250 MW range (especially keeping in view the significant backlog from the 11th plan).

5.3 As per the earlier survey commissioned by the CEA (for 85 plants), taking into account the average station heat rate for this fleet, (around 2600), and aux power consumption (average 11%), even without considering fuel oil consumption, the net plant heat rate was around 2900 when the survey was carried out.

> GSECL Ukai unit-1's case is an example: The pre-R&M DPR had predicted a heat rate of 2482 kcal/ kWH after the R&M implementation; going by the realistic benchmarks for 120 MW fleet, it is not clear as to how such a 'near –impossible' projection was done since the figure touches the station heat rate for a newly built unit!

5.4 In the context, as per information available in the public domain, R&M in overseas plants rarely have efficiency improvements beyond 10% from base value.

5.5 Even if these levels of efficiency improvements are achieved, it still leaves a gap of around 400- 500 kcal/ kWh, or about 20%. For say 15 units of 200 MW, this will entail an additional coal requirement of ~ 2.0 – 2.5 million tonnes per annum conservatively.

5.6 The CAG report quotes turbine vibration and boiler tube leakage as the reasons for lower than predicted performance in respect of GSECL Ukai; however, this is ironic since R&M, done at huge cost to the public exchequer was undertaken precisely to set right all those problems in the first place.

5.7 As already stated, even accepting the complexity of evaluating an LE project, it is necessary to rationally question the economic indicators projected before it is taken forward.

5.8 Further, results of the R&M performed in many plants abroad shows improvement in efficiency of maximum 10% from the base.

5.9 The matter needs to be seen from the perspective of India's effort cut down the GHGs progressively; hence the need to explore whether LE projects, at least some of them, can be switched over to replacement projects**.**

5.10 However, the 500 MW unit fleet, many of them installed during the past two decades, are expected to be serious candidates of R&M. It is expected that since the overall performance of these units has been better when compared to the 210/ 250 MW units, with minimal Capex, these could be upgraded.

5.11 As already flagged by policy makers, since energy efficiency is becoming exigent keeping in view the fact that India's coal import dependence has been increasing over the years, this aspect should get reflected in the R&M effort also. A few focus areas are listed below. Many of these measures are applicable to Greenfield projects also.

5.11.1 Reduction of heat loss from power plant: From a typical 660 MW power plant, a heat loss of 0.2% means saving about 6000- 7000 tonnes of coal and consequent reduction in emission. The following are suggested measures.

5.11.2 Till now, the thermal insulation is designed for nominal surface temperature of 60 °C; this value was fixed more than two decades ago when energy cost was insignificant and quality insulation was not available at economic prices. It may be prudent now to revisit this issue and carry out a cost-benefit analysis towards reducing the heat loss of all equipment.

5.11.3 Use of soft seals for air preheater: Air preheater losses are one of the prime 'leakage' points of boilers with multiple implications; Apart from increasing the losses from the boiler, it taxes both FD and ID fans by pushing in and pulling out more air/ flue gas. Hence soft seals of hastelloy etc. can be tried out.

5.11.4 Use of brush seals for turbines: (refer earlier explanation).This may be cost-effective for LE projects only for large units.

5.11.5 Plants with enough population of units, say 4 units or more, can seriously explore changing all 3 x 50 % pumps,(also fans if applicable), to 1 x 100% since, over a period of time, the savings in energy might offset any loss on account of occasional non-availability.

5.11.6 The dynamic pulveriser has gained acceptability; since it can improve the fines, there is a potential for improving the boiler efficiency by reducing the un-burnt carbon; this is particularly useful for coal with high fuel ratio.

5.11.7 Going for ceramic mattresses can improve ease of maintenance and at the same time provide improved start uptime in some cases.

5.11.8 Reduction of pump heads: By far this is one area which will give improvement on multiple fronts: In many old plants (even in some of the recent ones), excessive margins have been put for critical pumps like boiler feed pump, condensate extraction and even cooling water pumps.

5.11.9 In case where water system needs an overhaul, carry out a study between energy gain by increasing the pipe size and reducing pump head wherever feasible.

5.11.10 Generator: Many of the old units use lower pressure hydrogen (3.2 bar or below). Since generator efficiency improves with higher hydrogen pressure, it is worthwhile to explore retrofit of higher pressure hydrogen system.

5.11.11 Further, depending on the benefit to cost for specific cases, incorporation of modern practices in maintenance techniques (predictive/ performance driven) can be explored.

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Section V
Gas Based Power Generation

1.0 INTRODUCTION

1.1 Compared to steam turbines, the technology of gas turbines is more complex since it requires close integration of the three major components, compressor, combustor and turbine, manoeuvring the balance amongst efficiency, reliability and emission performance across the entire operating range. Because of this, the numbers of gas turbine OEMs are far less in relation to thesteam turbines.

1.2 The gas turbines are rated for their output and efficiency at ISO conditions (15 °C and mean sea level conditions) since both output and efficiency vary based on the mass flow entering the compressor.

2.0 MAJOR GAS TURBINE OEMS

2.1 Globally, there are more than two dozen gas turbine (GT) suppliers. However, for large size utility power, the bulk of the market is shared by the following four OEMs

- General Electric (GE)
- SIEMENS
- MITSUBISHI HEAVY INDUSTRIES (MHI)
- ALSTOM

2.2 In the mid-segment, HITACHI has developed GTs up to 110 MW with efficiency comparable to major OEMs.

2.3 In the smaller segment, following are the major technology holders:

- Rolls Royce
- Pratt &Whitney
- Solar Turbines

2.4 However, a number of manufacturers make GTs under license from the OEMs. In India, BHEL is a licensee of GE for manufacture of GTs up to F Class.

3.0 GAS TURBINES TECHNOLOGY: HEAVY DUTY AND AERODERIVATIVES.

3.1 Basically there are two types of gas turbines which are operationally matured:

- Aero-derivatives
- Industrial heavy duty.

3.2 Aero-derivative machines:

3.2.1 The aero-derivative GTs has been evolved from aircraft engines with requisite modification for stationary, land based power for continuous operation. These are characterised by:

- Significantly higher efficiency in OC mode for comparable size.
- Fast start up.

3.2.2 Lower foot print.

3.2.3 Aero-derivative machines, being primarily evolved from aircraft engines, were limited by their small size for long; however, of late up to 100 MW is available, making them suitable for peaking/standby power applications.

3.2.4 The drawback of these machines was the tight operational parameters in which they were to be handled- special lubricants, relatively high maintenance owing to their elevated firing temperature, etc.

3.2.5 Further, since they operate at fairly high pressure ratios (which give them the higher efficiency), many times they require an external fuel gas compressor.

3.2.6 Apart from this, with their lower mass to power ratio, the stability of these machines was poor. However, of late, many of these shortcomings have reportedly been circumvented.

3.2.7 However, aero-derivatives lose part of the improved efficiency in the OC mode when it comes to configuring a CCGT. This is because the exhaust mass flow rates of aero-derivatives are far lower which reduces the steam generation and hence the size of the steam turbine.

3.2.8 Pratt&Whitney, Rolls Royce and GE are the major OEMs in the aero-derivative range.

3.3 Industrial Heavy Duty:

3.3.1 Industrial heavy duty GTs are characterised by high ruggedness, moderate to high efficiency and have an array of ranges. Further, they can operate longer between overhauls, and are more suited for continuous base-load operation with longer inspection and maintenance intervals than aero-derivative machines.

3.3.2 Today, the core of the large Combined Cycle Gas Turbine (CCGT) plants across the globe is made up of these machines.

3.3.3 Because of their simple construction and wide range of capacities, heavy duty machines form the bulk of the power plant fleet across the globe.

3.3.4 However, of late, owing to use of higher pressure ratios and firing temperature, the efficiencies of heavy duty machines are comparable to those of their aero-derivative counterparts.

4.0 FUEL FLEXIBILITY:

4.1 Gas turbines operate with the best efficiency with natural gas. Since natural gas is available in most parts of the world with a fuel range between 8000 to 10000 kCal/ SM^3, gas turbines are normally designed for this.

4.2 Though they can be fired with other fuels like distillate, there will be some tax on both output and efficiency. However, almost all GT OEMs have factored in the increasing demand for fuel flexibility and have been designing gas turbine combustors with suitable modifications.

5.0 GAS TURBINE OPERATION

5.1 The gas turbines can operate in two primary modes for power generation:

- Simple (Open Cycle or OC) cycle mode
- Combined Cycle Gas Turbine(CCGT) mode
- Cogeneration
- Combined Cycle Cogeneration

5.2 Open Cycle Mode

5.2.1 In the open cycle, the turbine operates on a stand-alone basis. After generation of power, the exhaust gas is let into the atmosphere.

5.2.2 Since the exhaust gas contains a substantial amount of heat energy at relatively high temperature (550 – 600 °C in large turbines), this goes as a waste unless recovered. In view of the escalating fuel costs the world over, the open cycle operation of gas turbines is nowadays confined to stand-alone small/mid-size units for remote locations or as peaking power.

5.3 Combined Cycle Gas Turbine (CCGT) mode

5.3.1 As primary power generation equipment, gas turbines are nowadays operated as CCGTs in view of the significant potential of power generation from the exhaust gases.

5.3.2 In combined cycle mode, the exhaust gas from the turbine is used to generate high pressure high temperature steam through a Heat Recovery Steam Generator (HRSG) to drive a steam turbine.

5.3.3 In modern units, in order to utilise the maximum feasible heat energy from GT exhaust gases, the steam is generated at three pressure levels.

5.3.4 Nowadays, gas turbines at the upper end of the rating curve are offered only as combined cycle units. In fact, modern large size units from all OEMs are nowadays packaged only for CCGT applications.

5.4 **Cogeneration mode:**

5.4.1 Where the application demands low pressure steam in significant quantities, gas turbines can be used in conjunction with an HRSG without a steam turbine. This is called the Cogeneration mode. Typical application is desalination prevalent in Middle East countries.

5.5 Combined Cycle Cogeneration mode:

5.5.1 The Cogeneration combined cycle is primarily a CCGT mode with either of the following variations:

i). Part of the steam is extracted from the steam turbine (ST) inter-stage

or

ii). The steam generation from the HRSG is designed in such a way that the requisite amount of steam is produced at medium / low pressure as applicable and sent directly to process applications bypassing the ST.

5.5.2 Of all the four modes described, the most common universally is the Combined Cycle mode for power generation. Hence further discussion is confined to CCGT units.

6.0 PERFORMANCE

6.1 Typical performance of gas turbines in Combined Cycle mode along with other relevant technical data is tabulated below:

TABLE 5.1: TYPICAL TECHNICAL AND PERFORMANCE DATA FOR A CCGT UNIT

Sl. No.	PARAMETER	VALUE
1	No. of gas turbines	2
2	Exhaust gas mass flow, TPH	2470
3	Exhaust gas Temp	~ 600 °C
4	HRSG	2; Triple pressure; reheat; once thru high pressure
5	No. of steam turbines	1; HP, IP LP modules Titanium 1245 mm LSB

Sl. No.	PARAMETER	VALUE
		Steam sealing with brush seals
6	Gross Power Output	876
7	Design ambient temp, °C	10
8	Condenser	Titanium tubes
9	Exhaust pressure	0.045 bar
10	No. of starts per year (design)	200
11	NOx emission, ppm	25
12	Efficiency on Natural Gas , %	59

6.2 Auxiliary Power: Aux power for CCGTs working on natural gas varies between 1.7 to 2.5% depending on the size of the plant.

6.3 Environmental performance:

6.3.1 CO_2: The CO_2 emission from a large sized (400MW plus) CCGT is around 350- 450 kg/ MWh, about half that of a subcritical coal based unit.

6.3.2 NOx: The Typical value is 0.3 g/ kWh, without any end-of-pipe systems like SCR. With SCR, the value can come down to 0.1- 0.15 range.

6.3.3 SOx: Since natural gas normally contains only traces of SO_2, no significant proportion of SO_2 is emitted from CCGT units.

6.4 Factors affecting gas turbine performance:

6.4.1 By far the two most significant factors which affect the combined cycle performance are the pressure ratio of the gas turbine and turbine inlet temperature

6.4.2 Other variables which also contribute to the performance are

- Ambient conditions (Temperature, altitude which determines inlet air density)
- Pinch point of the HRSG and the number of pressure levels.

6.4.3 While the turbine inlet temperature and compressor pressure ratio are parameters under purview of the OEM and a matter of progressive research, the ambient conditions and pinch point of HRSG can be varied by the CCGT system designer according to individual project's economic drivers.

6.4.4 The common method of varying the ambient conditions are:
i) Chilling of compressor Inlet air by refrigeration
ii). Evaporative cooling.

6.4.5 While evaporative cooling is the cheaper option, its effect also depends upon the ambient humidity; evaporative cooling can increase the power output by 5- 8 %; however, the overall efficiency will drop. Hence it is used at places where fuel costs are moderate.

6.4.6 Chilling by refrigeration increases the auxiliary power consumption and hence it requires cost-benefit analysis for a given case. In combined cycle cogen cases, it may make economic sense to optimise the steam extraction for the plant with the steam of vapour absorption refrigeration for the inlet air chiller. The effect of inlet chilling has been demonstrated by a case study conducted on a plant in Thailand [78] ; the salient aspects are listed below:

- Chilling increased the GT output by ~ 11%
- However, the steam diverted for the chilling application reduced the Steam turbine output by 2.5%
- Overall improvement in the CCGT output was ~ 6.2 %.

- It was found that the additional investment of installing chillers and integration was being paid back in less than 4 years.

6.4.7 In general, with high fuel cost, or where revenue generation from generation of additional power is significantly higher than the cost of generation, the economics of inlet chilling may be attractive.

6.4.8 In some cases, the capacity of the steam turbine unit is increased by adopting duct firing or sometimes full-fledged supplementary fuel firing in the HRSG.

6.4.9 For large size units, nowadays it has become a standard feature to resort to triple pressure HRSG. Pinch point also can be varied only to a limited extent since below some threshold values; the Capex of HRSG escalates beyond an economically viable limit.

7.0 AVAILABILITY AND PERFORMANCE DEGRADATION

7.1 General:

7.1.1 Unlike steam turbines where the working fluid is relatively clean and which operate at fairly moderate temperatures (500- 600 °C), the gas turbine being a direct fired machine operates with a heterogeneous working fluid at relatively high temperature. Hence the degree of degradation of the gas turbine is far higher as compared to that of a steam turbine.

7.1.2 Further, gas turbines operate with different kinds of fuels like distillate and even residual fuels in some cases. Since the GTs are designed for natural gas as fuel, change of fuel can influence the flame characteristics and fluid kinetics inside the turbines and unless these are factored into the operation, can potentially increase the downtime.

7.1.3 Apart from these, in view of their inherent characteristics of faster start up and shut down, CCGT units are subjected to cyclic and peaking duties in many parts of the world.

7.1.4 All these cumulatively contribute to the increase of degradation of the CCGT units, especially gas turbines.

7.1.5 Gas turbine OEMs capture the above features by way of Equivalent Operating Hours (EOH) while predicting its life or assessing damages during an inspection. While these are applied to conventional thermal units also (like fatigue stress on account of cyclic duty), the implications are far higher in respect of GTs. [79]

7.1.6 EOH of a gas turbine is determined by the cumulative accounting of operation at peaking and with fuels other than natural gas, assigning multiple factors for such cases , as shown by following example:

↓

E.g.: a unit operating with liquid fuel for a peaking duty for 10 hours and hot start up within 5 hours is considered to have consumed 60 hours of its normal life with natural gas at base load condition.

8.0 CAPEX AND OPEX

8.1 Capex

8.1.1 Capex of CCGTs has been found to vary significantly. There are a number of reasons for this, primarily the class of the turbine. If the turbine offered is of advanced class, the associated higher efficiency will demand concurrent higher Capex.

8.1.2 The following table gives the envelope of the CCGT costs projected from US, Europe and Asia.

TABLE 5.2 : RANGE OF CCGT PROJECT COST ACROSS THE GLOBE

Sl no.	DESCRIPTION	US DOE (NETL) Sept 2013	IEA (2010)	KEMA (2013)	REMARKS
1	SIZE, MW, Net	565	622	820	Both US and IEA data are projections for generic cases; KEMA data is for a specific project in Singapore arrived at after detailed estimate. Cost has been converted from $SG @ 1$US= 1.25 $SG
2	COST BASE	2007	2008	2013	
3	CAPEX, $/ kW	771	1000-1250	1200	

8.1.3 It can be seen that :

- The cost projected in the US happens to be at the lowest band. The prime reason is the significantly higher population of CCGTs in the US and hence perhaps economies of scale, cost of components, pre-engineering of subsystems etc.; a matured market ensures competitive prices. Plus additional transportation, logistics and personal costs.

8.2 OPEX

8.2.1 The O&M cost (sum of fixed and variable cost) of CCGT estimated by US NETL (2013) is $4.3 / MWh.

8.2.2 In respect of Opex, however, there is a major difference between conventional coal based projects and CCGT projects.

8.2.3 In case of conventional thermal projects, the O&M cost is fairly evened out between the Power Island and the balance of plant. However, in case of CCGT, the bulk of the O&M cost is attributed to the cost of spares of the gas turbine. This is so because the degradation of gas turbine components, especially those of advanced class machines used in modern units in view of the rigorous environments in which they operate, is far higher when compared to the steam based units and hence they need faster replacements.

9.0 ADVANCES IN GAS TURBINE TECHNOLOGY

9.1 General:

9.1.1 Since gas fired thermal units occupy a significant share of the utility power market, continuous research has been on-going for overall improvement in the performance of the gas turbine unit.

9.1.2 One of the recent developments in this context is the challenges associated with customising gas turbine design for syngas firing in IGCC mode of operation. In view of the wide variation between the characteristics of syngas from the natural gas (low heat content, high hydrogen content etc.) a number of design changes were necessitated.

9.2 Oxy- Fuel Gas turbine.

9.2.1 Oxy-fuel gas turbine utilises oxygen instead of air for combustion. However, it will call for a very basic change in gas turbine design, like recycling of flue gas, in order to maintain acceptable temperatures for turbine blades. [80]

9.2.2 The change in the working fluid from air to a CO2-rich gas will significantly alter the properties factored into turbine design.

9.2.3 The oxy-fuel gas turbine concept was an offshoot of CO2 capture technology. However, the major determining factor in the cost and efficiency of oxy-fuel CO2 capture is the production of oxygen. The methods in use for oxygen production today are quite energy demanding. The most common method today is cryogenic oxygen production.

9.3 A promising future technology is using high temperature ceramic membranes to separate oxygen from air. This technology may produce high purity O2 at a lower cost than cryogenic oxygen production. This technology is currently in the pilot plant stage, and large scale production may be available in a few years.

9.4 A few of the recent advances in the gas turbine technology across major OEMs are listed below:

9.5 GE :

9.5.1 Monitoring and detection system: GE has developed a Monitoring and Diagnostic system to facilitate early detection of potential failure areas and thus prevent forced outage of machines. [81]

9.5.2 The M&D system covers the entire gas turbine such as

- compressor stator vane crack detection
- blade crack detection
- combustor liner cracking
- thermal barrier coating spallation
- hot gas path component degradation
- fuel contaminant monitoring etc.

9.6 MHI :

9.6.1 MHI has recently developed an upgraded air-cooled machine with model name M501GAC with an open air cooling scheme. Though the efficiency is in the vicinity of 59%, air cooling will facilitate faster start up for cyclic applications. It has a turbine inlet temperature (TIT) of 1500°C and claims NOx less than 15 ppm. [82]

9.6.2 MHI model M501J, with 1600 °C TIT, developed in the preceding years and commissioned in February 2011 at the MHI demonstration plant, in Takasago, Japan, reportedly went commercial on July 1, 2011after undergoing numerous tests including measurement of more than 2,300 temporary data points. As of March 2012, this machine has accumulated more than 5300 actual operating hours and 62 starts.

9.6.3 Further, MHI has been engaged since 2004 in a Japanese National Project for the development of a 1,700°C class gas turbine as the innovative efficient combined cycle power plant. This is an on-going project aimed at reaching CCGT efficiency in the vicinity of 65%. As part of this project, the following areas have been the focus of research:

- Exhaust gas recirculation combustor for lower emissions
- Higher turbine cooling efficiency
- Advanced thermal barrier coating

- Higher pressure ratio compressor
- Advanced heat resistant turbine materials
- Turbine aerodynamics

9.7 SIEMENS:

9.7.1 In one of the most recent developments, SIEMENS has commenced commercial production of aerofoil ceramic cores for gas turbine blades and vanes using the TOMO^{SM} technology in a Technology License agreement with Mikro Systems Inc. which had developed this technology with funding from the US DOE. The advancements are expected to improve the cooling capability of gas turbine blading, thus enabling higher levels of turbine performance and efficiency for forthcoming Siemens Gas Turbines. (www.yahoo.com/news/businesswire)

9.8 ALSTOM:

9.8.1 Alstom has reportedly recently joined a collaborative effort initiated by German Aerospace Centre (DLR) along with Rolls Royce towards investigating development of environmentally friendly gas turbines. The research programs main aim is to develop, along with improved efficiency, reduction in emission and noise. (www.alstom.com)

9.9 The following is an extract of the US EPRI report published in 2012 providing some of the very recent technical data and performance figures of large size as CCGT models from the four major OEMs. [83]

TABLE 5.3: TECHNICAL DATA AND PERF. FIGURES FOR CCGT UNITS ACROSS MAJOR OEMs

Description	Siemens SGT5-8000H SGT6-8000H	Mitsubishi M701J M501J	Alstom GT26 Uprate GT24 Uprate	General Electric 9FB New
Status	Commercial Operation	Commercial Installation	Testing Complete	Preparation for Testing
Efficiency ,%	60.75	>60	>61	>61
Compressor Stages	13	15	22	14
Compression Ratio	19.2:1	23:01	>33.0:1	19.6:1
Combustor Type	Can-Annular DLN	Can-Annular DLN	Annular DLN sequential	Can-Annular DLN
Comb. Liner Cooling	Air	Steam	Air	Air
Turbine Stages	4	4	4	4
Hot Start Time, min.	30	70	30	30
Ramp Rate, %/min.	6.1 max.	-	4.6 avg.	10 max.
CC Turndown Load, %	-	-	20	40
GT Turndown Load, %	40	-	-	30

Note: the efficiency indicated are gross efficiencies.

9.10 INSTITUTIONALLY FUNDED PROGRAMS

9.10.1 In 2012, the US DOE had commissioned its Hydrogen turbine program under active collaboration with US academia and turbine OEMs GE and SIEMENS. [84]

9.10.2 The primary motivation of DOE, it appears is building up gas turbine power technology towards carbon capture and usage.

9.10.3 There are altogether 36 programs identified across heat transfer, materials, combustion and thermal barrier coatings.

9.10.4 The broad objectives of the programs are:

- 3- 5 % improvements in CCGT efficiency by 2015.
- 4% improvements in IGCC efficiency with CCUS by 2015
- Turbine NOx emissions to be brought down to single digits
- IGCC plant optimized for firing temperature with 2 ppm NOx at the stack

9.10.5 Some of these programs also aim to develop gas turbines operating with syngas for higher firing temperatures.

10.0 SHIFTING LANDSCAPE: BALANCING FLEXIBILITY WITH EFFICIENCY

10.1 General:

10.1.1 As per a survey by the US EPRI, 26% of CCGT units in US are on cyclic duty while only 23 % are operating on base load.

10.1.2 Since conventional solid fuel fired thermal units take far longer to start up and shut down, the natural choice for coping with the dispatch regime's ramp up requirement falls on CCGT units.

10.1.3 However, this shift in the operating regime put a lot of constraints on the CCGT equipments such as :

- ➢ It progressively increased the number of start-ups with concurrent increase in start-up fuel losses
- ➢ It increased significantly the EOH of the units and consequently reduced the life span.
- ➢ It increased atmospheric emission on unit electricity generated

10.1.4 However, compared to earlier days, the revenue generation of the utility industry has also changed with the emergence of peaking and merchant power in many countries. Hence utilities attempt to trade-off between the increased costs of fuel with improved revenue from flexibility.

10.2 CCGT units: Change in the operating regime:

10.2.1 The change in the start-up time periods of older units of CCGT and those recently built is tabulated below:

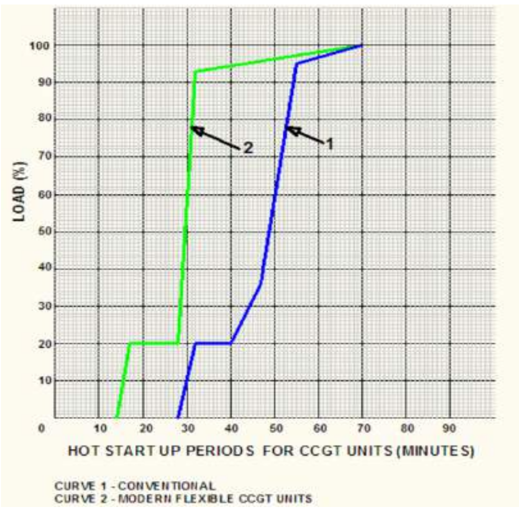
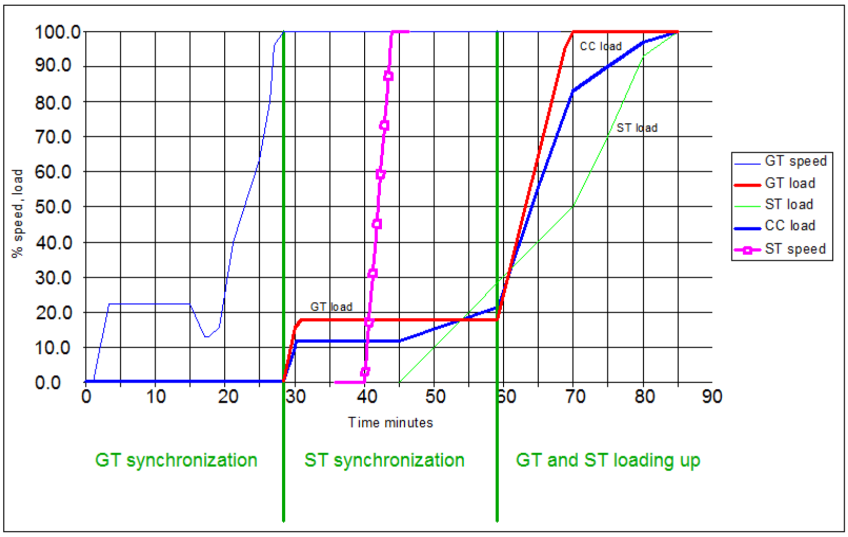


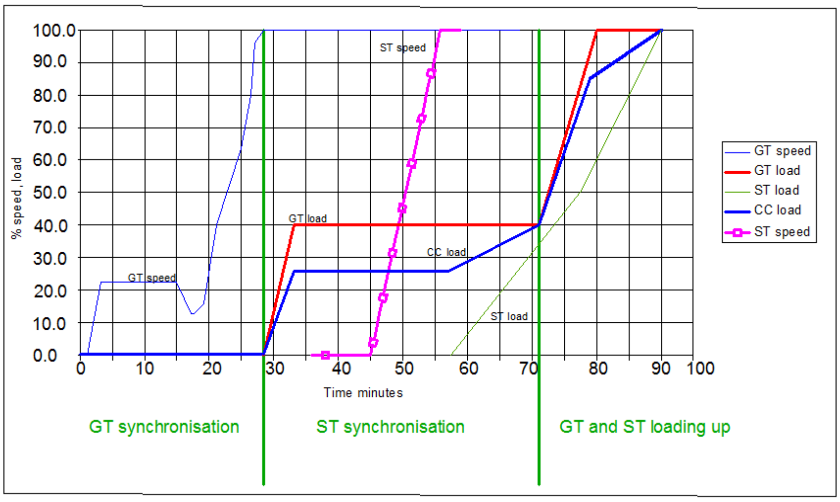
CHART 5.1: EVOLUTION OF CCGT START UP REGIME

10.2.2 The CCGT units of yesteryears had been designed in such a way that the best operating efficiency was close to the rated load of the unit. This resulted in the efficiency of the unit falling fast below typically 80% load. The primary reason is attributed to the technology itself wherein the compressor, even at no load condition, consumes significant power.

10.2.3 The start-up systems of earlier units and flexible units being built nowadays are shown below. The improvement in the start-up and load ramp up is clearly visible.



START UP SYSTEM EARLIER



MODERN START UP SYSTEM

CHART 5.2 : EVOLUTION OF START UP CHARACTERISTICS OF CCGT UNITS

10.2.4 It should however be noted that these faster start-ups have been brought about by improved instrumentation and shift in start-up logics, and additional hardware. Some of these features are described below.

10.2.5 Most of the OEMs have achieved basic improvement in the start-up time duration of CCGT units by eliminating the HRSG purge sequence and hold time at low load with reduced exhaust energy, (towards controlling the HRSG steam production rate and steam temperatures).

10.2.6 HRSG purge sequence has been eliminated by advancing this activity right after the shutdown.

10.2.7 Elimination of low load holdup time for direct HRSG steam temperature control via GT load and exhaust energy can be accomplished via a bypass stack and modulated damper controlling the exhaust flow to the HRSG. In some designs, air attemperation of the GT exhaust gas flow via air injection into the transition duct leading to the HRSG is employed.

10.2.8 For further incremental improvements in the start up time cylindrical, thin-walled knock-out vessels are employed in order to avert thermal stress encountered during cold starts instead of a steam drum, (which has thick walls and consequently has to follow lower ramp up rates).

10.2.9 It is also possible to reduce the heat loss from HRSG circuit by bottling up the HRSG via stack dampers with insulation up to the damper. These are however, customised for specific operating regimes and may not be standard features of typical flexible CGTs.

10.2.10 As per a report by the Combined Cycle User Groups, (www.ccj-online.com, Oct 2013), in Lodi Energy Centre, California, for the 300 MW monoblock, (1 GTG+1 STG), CCGT unit, the requisite operational flexibility has been achieved by significantly ramping up the instrumentation,(E.g.: the number of analysers almost equivalent to a 3x1 Configured CCGT unit).

10.2.11 The report also brings out that finding a balance between flexible operations and complying with the emission target is also tricky, calling for continuous tuning of the operational parameters.

10.2.12 Some of the current CCGT designs across OEMs show the following characteristics in respect of flexibility [85] :
i). GE claims a 10% ramp up per minute on a unit in the 500 MW range with hot start up to full load in 28 minutes while maintaining 50 ppm NOx. It further claims only 1% reduction in the efficiency down to 87% of the load. One major feature of flexible efficiency models has been the dry Low NOx Axial Fuel Staged combustion system which provides advanced fuel staging for enhanced steady state and transient performance with emissions less than 25 ppm NOx and CO.

ii). Alstom is claiming 30 minutes hot start up for its KA-26 based CCGT. Further, with its KA- 24 machine on 2-1 configuration (2 GTs and 1 ST), it claims to have vastly improved spinning reserve capable of delivering 450 MW in a 10 minutes period. Alstom has patented an innovated combustion design titled 'Sequential Combustion' and multiple variable compressor guide vanes—to optimize the difficult combination of high efficiency plus low plant turn-down with low emissions. They claim almost flat efficiency down to 80 % load. Further, their GT26 has two online switchable control modes with maintenance implications. The first one, 'Performance optimized' mode, uses higher turbine firing and exhaust temperatures to maximize power output, while the other one, 'lifetime optimized' mode, lowers firing/exhaust temperatures, allowing up to 30% longer turbine inspection intervals, as they claim.

iii). SIEMENS, with its H class FACY (fast and cycling) design experience at Irsching (Germany) claims to have achieved several milestones: A hot start up capability below 30 minutes, plant shut down in 30 minutes and surpassing the stringent UK grid code requirements. SIEMENS claim that, despite its size, the plant can run stably at around 100 MW, less than 20 per cent of its total rated output, in combined-cycle mode with only moderate variation in efficiency.

iv). MHI claims to have achieved a part load efficiency of 55% at 50 % CCGT load.
Of course, in general, some of these are relatively nascent developments and a final call about the authenticity of the claim can be taken only after independent verification of adequate operational experience at multiple plants.

1.1.1 Shutdown/ramp down Characteristics: Shutdown characteristics of the CCGT units are by and large similar to the start up ramp up or better [131]. As per a SIEMENS report, the 578 MW unit at Irsching #4 has been demonstrated to shut down within 30 minutes.
Further, SIEMENS also claim to have demonstrated the fast ramp down,(akin to block load throw off), of 45 % load in 6 seconds without disturbing grid characteristics [129] as mentioned earlier.

1.1.2 However, the ramp up/ down characteristic also depends on the configuration of the CCGT i.e.: the number of GTGs / STGs in the module. Typically for a 2 x 1, (2 GTG /1 STG), configuration of mid-size units, the shutdown of the STG commences[131] when the power drops to 50% with complete shutdown in around 15 minutes.

11.0 CARBON CAPTURE WITH CCGT UNITS

11.1 CO2 can be captured from NGCC units by all three methods i.e. pre-combustion, post-combustion and oxy-combustion methods.

11.2 The results of a study by US DOE on a post-combustion capture case for an NGCC unit is tabulated below which shows the difference in performance parameters. [28]

TABLE 5.4 : CCGT PERFORMNACE WITH AND W/O CO_2 CAPTURE

Sl No.	Parameter	CCGT w/o Capture	CCGT with capture
1	Gross Power generated, MW	564	511
2	Total auxiliaries, MW	9.62	37.43
3	Net Power, MW	554.4	473.57
4	Net plant efficiency %	50.2	42.8
5	CO2 capture , %	Nil	90
6	Total cost at start of operation, $US/ kW	771	1614

11.3 From the table, the significant efficiency penalty and cost escalation on account of CO2 capture can be observed.

12.0 COMBINED CYCLE POWER UNITS IN INDIA

12.1 General:

12.1.1 In relation to coal fired units, the population of CCGT units in India has been fairly low, mainly owing to inadequate availability of natural gas. However, during the past 10 years, especially after 2005, a number of plants have been built.

12.1.2 The current installed capacity is about 20 GW.

12.1.3 One of the largest CCGTs is located at Dabhol which has 6 gas turbines and 3 steam turbines.

12.1.4 The units, installed about one and a half decades ago had undergone extensive downtime owing to failure of compressors (reportedly on 4 GTs).However, similar machines were installed subsequently at other projects and no major failure reports have been reported.

12.2 Capex

12.2.1 Cost data available from recent Indian projects are tabulated below:

TABLE 5.5 : CCGT PROJECT COST DATA FOR INDIAN PROJECTS

Sl no.	DESCRIPTION	Project 1	Project 2	Project 3	Project 4	REMARKS
1	SIZE, MW, Net	1500	800	727	160	Conversion considered: 1$US = Rs 62
2	COST BASE	2007	2010	2007	2008	
3	CAPEX, Rs Million	52000	32000	34300	6400	
4	CAPEX, $/ kW	560	650	760	660	

12.2.2 It can be observed that the there are no significant differences in cost between CCGT projects in India and overseas.

12.3 Opex

In respect of Opex also, the estimates for overseas projects (indicated earlier) are found to be in close range with the figures consented by CERC on Cost-plus projects in India

12.4 Present status of CCGTs in India

12.4.1 The combined power plant units in India have been going through an 'existential crisis' during the past few years on account of a severe crunch in the availability of fuel at economic prices.

12.4.2 A number of plants built after 2005, especially in the Krishna Godavari belt based on the projections of gas availability from Krishna- Godavari (KG) offshore basins are virtually closed.

12.4.3 A number of gas pipelines planned a few years ago connecting the major cities have either not taken off or are moving at a very slow pace in view of the general 'unease' about the prospects of gas availability in the medium term

12.4.4 The following chart depicts the picture of the overall CCGT regime in India. As observed from the chart, while there has been marginal addition to the installed capacity, the PLF has been steeply falling.

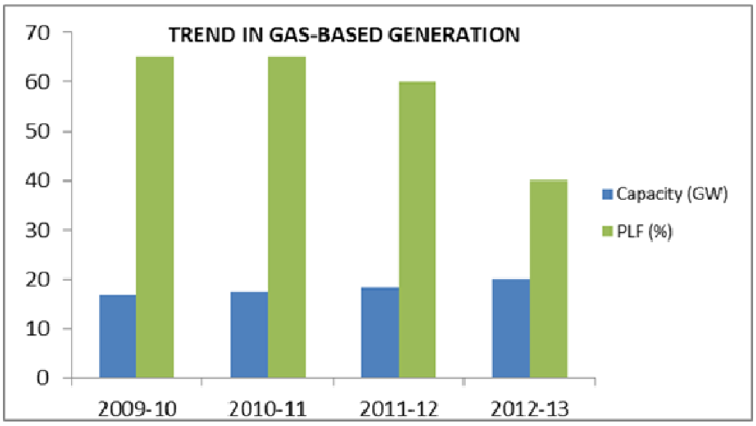


CHART 5.3: TREND IN GAS BASED POWER GENERATION I INDIA

12.5 Trends in gas based power generation in India

12.5.1 Recently there was a move by the MoP for seeking a cabinet nod for pooling of imported LNG with domestically available natural gas. However, it is understood that keeping in view the substantial cost ramifications on the exchequer by way of subsidy, the Planning Commission has not encouraged this. They have instead suggested allowing the concerned IPPs to sell 50 % of the output in open market.

12.5.2 The sensitivity of the electricity generation cost with the landed price of gas can be seen from the following chart. The station heat rate considered is 1800 kCal/ kWh for Indian conditions.

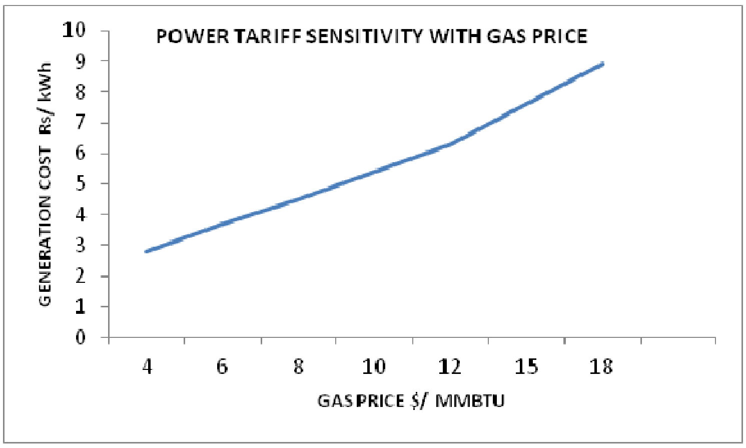


CHART 5.4: SENSITIVITY CHART FOR ELECTRICITY WITH CCGT

12.5.3 Since fixed cost of generation is almost constant, the gross generation cost varies linearly with the cost of fuel.

12.5.4 Just for the sake of comparison, it may be worth noting that the cost of generation of power from coal based units with a median landed price of coal, say Rs 2000/ Ton, is ~ Rs 2.5 / kWh.

12.5.5 From investor's perspective, having seen their substantial investment turn into non-performing assets before even the closure of the project's debt, now, even if some green shoots starts on the horizon, it will take a while to convince them to invest in any fresh venture in CCGT projects in India.

12.5.6 In summary, keeping in view the current status and visibility available in the short term, it is very unlikely that any gas based unit will come up in India in the immediate future.

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Section VI
Operational Flexibility of Thermal Power Units

1.0 BACKING UP RENEWABLE GENERATION

1.1 Though this subject has received attention in India only fairly recently, it was studied in Europe earlier in view of the significant proportion of renewables in major European grids and normal export import happening across national boundaries, especially in Germany and Spain, where the installed capacity of renewables is a significant proportion of the total generation capacity. Further, there is a time difference between the peak wind generation and peak load demand. [86]

1.2 Some of the unique situation reported are :

- On a particular day, during non-peak hours, while only one CCGT unit was operating, by evening peak hours, the grid demand resulted in 27 CCGT units operating.

1.3 In India, Powergrid Corporation (PGCIL) had studied this issue to see the 'fault lines'. A few of the findings and statistics are listed below for sake of discussion[87]:

1.3.1 India's total 'uncontrollable renewables, solar and wind, together constitute less than 20 GW as on date, with wind's share at close to 18 GW. Of particular attention is the situation in the southern states, especially Tamil Nadu, as explained below.

1.3.2 The distribution of wind power across the country is shown below.

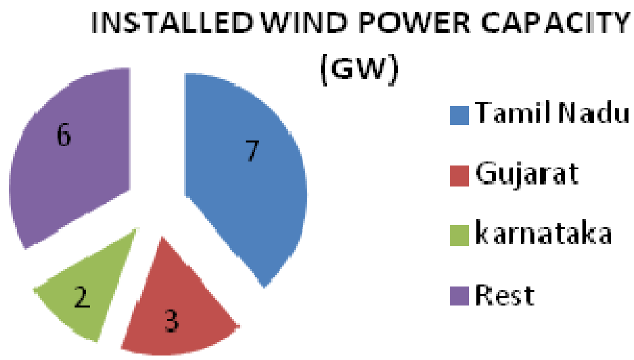

CHART 6.1 : INSTALLED WIND POWER CAPACITY IN INDIA

1.3.3 As can be seen from the pi-chart, two states contribute around half of the total wind power generation in the country.

1.3.4 The load pattern of the country shows the peak demand in the country as a whole is between 6 pm and 9 pm.

1.3.5 Further, the wind power is significant in southern states in relation to the installed capacity, especially in Tamil Nadu, which has got some analogy with European situation, though at a much lower scale.

1.3.6 It can be seen that the wind power capacity of Tamil Nadu in relation to its total load demand is significant and this will call for faster switching off and on of the thermal capacity in line with the variations in demand.

1.3.7 However it is also seen that the wind potential of Tamil Nadu is significant only 4 months in a year.

1.3.8 Further, peak demand in the southern region is between 6 am and 9 am in winter and between 7 pm and 9 pm in summer. The load generation study of Tamil Nadu shows that peak wind generation is between 1 pm and 4 pm whereas the load generation peaks are between 11 am and 9 pm for months when wind generation itself is significant. Again the peak wind generation in the vicinity of 3 GW is seen lasting for a very short duration of about 2 hours.

1.3.9 However, in the immediate term, the addition of base load capacity (primarily thermal), is going to be numerically far higher than the growth of wind/ solar power in southern region. Hence, the severity of fast switching on and off the thermal capacity may not be required.

1.3.10 Till recently, the southern grid was operating independent of the other three grids of the country for want of an adequate inter-regional transmission network. The Powergrid report has identified a specific transmission network.

1.3.11 Apart from these, along with improvement in thermal power response systems, technology for prediction of weather behaviour and smart grids are on the horizon and together these may be expected to smoothen out the grid operation.

1.4 Recently(Nov 2013) CEA has carried out a study for large scale RE integration into the grid for arriving at a way-forward. The study, amongst others, has compared the RE integration methods in major economies. The excerpts are as follows:

1.4.1 At present, the proportion of RE capacity in the total generation mix amongst major RE generating states are tabulated below:

TABLE 6.1: PROPORTION OF WIND POWER CAPCITY IN THE GENERATION MIX

Rajasthan	Gujarat	Karnataka	Tamil Nadu	All India
26%	18%	29%	40%	24%

1.4.2 Method of balancing the generation mix:

Tamil Nadu: The current generation mix does not appear to give much leeway for effective utilisation of the peak wind power generation and may require integration with other generating sources in the regions, besides extension of the spinning reserve available.

Gujarat: In case of the high wind low load scenario, backing down of state conventional generating units, reduction from the Central pool, reserve shut down of smaller units etc. are the suggested proposals.

Rajasthan: backing down of the thermal units is the only available solution as of now.

1.4.3 The study, in the process has also scanned the methods employed in major economies as enlisted below:

China: China has equipped all Wind Power Pants (WPPs) with control and monitoring systems that can communicate directly with the dispatching centres in real time. Further, based on the wind power forecasting at different time scales, a wind power optimal dispatching decision support system has also been developed.

Germany: With wind contributing significantly to the total power generation, Germany manages the balancing by very close co-ordination with the

neighbouring Transmission system operators both within and outside the country.
US: The sheer size of the country and different rules set by different grids across its geography has resulted in formulating different rules for scheduling of wind power for individual regions.

Japan: In Japan, bulk wind generation is far away from major load centres and the current capacity of inter-regional transmission system is not adequate enough to absorb the peak wind generation capacity resulting in, at times voluntarily curtailing the available wind energy.

1.4.4 The report states that in respect of India, the challenge for absorption of major renewables, solar and wind comes from the variability in generation.

1.4.5 The way forward suggested includes, amongst others, more simulation studies and better modelling of resources with help from overseas expertise along with strengthening of the transmission capacity.

2.0 ATTRIBUTES OF FLEXIBLE GENERATION OF THERMAL UNITS

2.1 Flexible operation of Thermal power units

2.1.1 Flexible operation of thermal units commonly known as 'Cycling' refers to the operation of electric generating units at varying load levels, in response to changes in consumer load requirements.

2.1.2 While load-following in a steady manner technically amounts to cycling, the effects of cycling on power plant equipments are more pronounced when they have to also start up and shut down and operate at minimum levels on a regular basis.

2.1.3 Cycling of thermal units has been routinely done in advanced economies for the last several years primarily in view of the significant electricity intensity (per capita consumption) and varying daily and weekly demands.

2.1.4 In the recent past, one more dimension has been added to this by way of the increasing share of renewables and emergence of priority dispatch regimes.

2.1.5 The other aspect is that nowadays, the price of electricity in unregulated sectors in many countries is elastic with the introduction of time of the day (TOD) rates.

2.1.6 Hence, from a business standpoint, cycling of plants is essentially leveraging opportunity of the market towards revenue optimisation.

2.1.7 The flexibility of a power generation technology is characterised primarily by the following attributes:

i). Ramp Rate
ii). Part load efficiency
iii).Cycling Ability
iv). Low load operation
v). Cost of ramping

2.2 Ramp Rates

2.2.1 The main reason for OEMs to prescribe ramping gradients is to ensure that the equipment sustains stresses by avoiding rather extreme temperature and pressure differences within the components of a plant so that there is no irrecoverable damage. However, from a utility perspective, higher ramp rates allow the unit to quickly increase the generation or back down in line with dispatch instructions.

2.2.2 A number of studies have been carried out to determine the ramp rates of thermal units across the globe. The results show widely diverging and contrasting figures, even from those with recent origins, as cited below.

2.2.3 Another implication of the ramp rate is that a slower ramp rate typically increases start up costs especially for coal based units, which normally require liquid fuel for start up.

TABLE 6.2: RAMP RATES OF THERMAL POWER UNITS(% POWER/ MINUTE)

Sl. No.	Source	Pulverised coal		CCGT	IGCC	Remarks
		Subcri.l	Supercrit.			
1	Current and prospective cost of electricity gen. until 2050- Andrea Schroder Friedrich Kunz et al (2013)	2 – 8	2- 8	2 - 12	-	Article, in turn cites several sources across Europe and US
2	Impact of load following on PP cost and performance(USDOE-NETL, 2012)	5	2	5	3 – 5 (ASU ramp rate 1- 2)	Article cites values based on several literatures/ interviews with experts
3	Cost and performance data for Powergen technologies (Black & Veach, 2012)	2		5	5 (2.5 for quick start)	
4	Summary Report on Coal Plant Dynamic Perf. Capability- Jimmy Lindsay and Ken Dragoon (2010)	3 - 5	7- 8	-	-	
5	Power Magazine (July 2005)		30- 50 % : 3 >50% : 5	-	-	This is for a 2 x 800 MW plant built in 2004.
6	21st Century coal: advanced technology and global energy solutions-OECD/IEA (2013)		3	3.5		
7	Operating flexibility of PP with CCS- IEA /GHG (2012)		30 - 50 % : 2 – 3 50- 90% : 4- 8 >90% : 3- 5	2 – 6	3 - 4	
8	Powergen Europe Conference paper (2013)	4 – 5		-	-	-

2.2.4 From the above, it can be seen that there are a number of contrasting figures in the tabulation. Since many sources have cited back-references, it is not possible to ascertain the authenticity of some figures.

2.2.5 However, one striking contrast can be seen in respect of subcritical Vs supercritical. Whereas one source indicates a higher ramp rate for subcritical, the other shows the exact opposite trend. The reason for this is explained earlier while comparing the load behaviour of Supercritical vs Subcritical in Section I, Cl 6.9

2.2.6 It can however be mentioned that since subcritical units are being replaced with supercritical units the world over, owing to the twin advantages of overall economics and environmental friendliness, OEMs are also exploring ways to improve the ramp rates by adopting several means, some of which are listed below:

i). Maintaining a full capacity turbine bypass system for a quick hot start up (instead of a partial bypass employed in typical Indian thermal power units)
ii. Providing automatic drains in the steam cycle
iii). Adopting thinner materials with better creep strength
iv). Improving pulveriser operation.
v). Improving the response of control system.
vi). Adopting measures to retain heat in boiler –turbine systems during brief shut downs.

2.2.7 Since supercritical units currently being built are of significantly large size,(600 – 1200 MW range), economies of scale render these units to incorporate the features listed above and hence it can be inferred that modern supercritical units will have far better ramp up characteristics.

2.2.8 Compared to PF units, the literature and operating data available in respect of CFBC based units is fairly limited.

2.2.9 For the Lagisza 460 MW, the first supercritical unit, the ramp up rate stated by the OEM is 4% per minute[89]whereas an independent report shows 2% per minute[90]. It is possible that the higher ramp up rate could have been achieved at the upper range of loads whereas the average ramp up rate could be at the lower.

2.2.10 Though the ramp up range of both PC and CFBC could be in the close range at a broader perspective, it is possible that the CFBC based units may have a marginally lower ramp rate keeping in view the difference in the burning characteristics. The ultrafine coal particles (around 200 microns in size) in the PC boiler provide a larger surface area for more efficient combustion compared to the larger coal particles (typically 6 mm) in CFB boilers. [91]

2.2.11 Ramp rates of OCGT are marginally higher by inherent design. The typical range is 8- 12%. As mentioned earlier, the need for flexible operation is forcing the OEMs to improve the ramp up rate with lower damage to equipment.

2.2.12 As for IGCCs, though some literature, (as listed in Table 6.2), indicates ramp rates of 3- 4 %(which is in close range with PC based technologies), inherent characteristics of the technology suggest lower ramp rates. The laggard appears to be the ASU which is reported to have ramp rates of 1 to 3 %. (Table 6.2).
Further, operational experience [92]also indicates the ramp rate of IGCC at around 1%.

2.2.13 The Ultrasupercritical PF units are expected to have marginally lower ramp rates compared to their supercritical peers in view of more sensitive metallurgy in case of the former.

2.3 Part Load Efficiency

2.3.1 The reduction in net efficiencies at decreasing loads of various technologies is tabulated below(in %)[93,94] :

TABLE 6.3: PART LOAD EFFICIENCIES OF THERMAL TECHNOLOGIES

PF / CFBC	CCGT	OCGT	IGCC
80% : 1.5 60% : 4 40% : 6	80% : 3 60% : 6– 8 40% : 12 – 14	80% : 4 60% :7 – 10 40% : 14 – 16	80% : 4 60% : 8 – 10

Note: IGCC part loads efficiencies are estimated figures

2.3.2 The figures indicated are the reduction from the base (rated) load on net basis.

2.3.3 These are diagrammatically represented as a chart below. For readability, the charts have been split with one for PF/CFBC &CCGT units and the other for OCGT/ IGCC units.

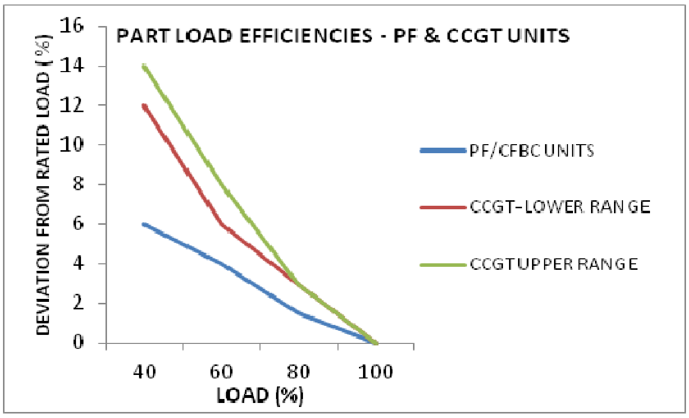

CHART 6.2: TREND OF PART LOAD EFFICIENCIES OF PF/CFBC& CCGT UNITS

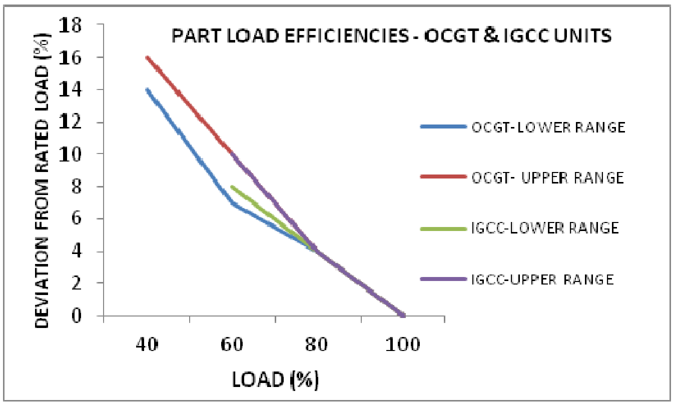

CHART 6.3: TREND OF PART LOAD EFFICIENCIES OF OCGT/ IGCC UNITS

2.3.4 Part load efficiencies of pulverised and CFBC based units are seen moving in a narrow range in the upper band of the operation window. In some designs of CFBC, since fans contribute a significant part of auxiliary power consumption, net efficiencies at lower loads could be lower than an identically rated PF unit.

2.3.5 In case of PF based units, supercritical units will have marginally higher efficiency at part loads since most of the units operate at sliding pressure operation.

2.3.6 In case of IGCC, the reduction at lower loads is more since the auxiliary power consumption, which is 3 to 4 times higher as compared to PC based units, does not get reduced in the same proportion to the reduction in the load.

2.4 Variation of Emission with Load:

2.4.1 Since environmental aspects are also equally important while dealing with flexible operation, it is necessary to get a peek into how different technologies behave at part loads. This aspect is discussed below.

2.4.2 NOx:

i).Nitrogen oxides are typically highest in PF technology,(300 - 1000 ppm), and lowest in Gas turbines, (5 - 25 ppm). Intermediate values are observed in FBC boilers.

ii).In case of PF boilers, it has been found[95]that the NOx varies in a close range from 80 to 100% load; below this, it decreases in a narrow range 8 to 10%.

iii).In case of FBC, the minimum NOX has been observed for around 80% load. At the rated load, the NOx has been found to be ~ 15 % higher; however, at lower load, the rate of increase has been found to be higher when compared to load variation upwards of 80%. At about 40% load, the NOx has been observed to be about 50% higher as compared to 80% load [96].

iv). For Gas turbines, the NOx has been found to reduce with the load in view of lower peak flame temperature.

2.4.3 SOx:

i). For PF boilers, typically FGD has been used. No appreciable change has been observed in the SOx absorption with load variation [97].

ii). In case of FBC, there will be marginal improvement in SOx retention with lower loads in view of lower fluidisation velocity and hence higher residence time. However, fuel quality also affects the sulphur absorption since bed temperature has to vary depending on the fuel type, (lowest for petcoke and highest for anthracite coal).

iii).Since gas turbines typically utilise natural gas, normally SOx is not associated with CCGT operation.

2.4.4 SPM:

The performance of ESP has been found to be improved for lower loads. The relative improvement depends on the base efficiency. For a typical ESP with 99.9% base efficiency, 50% reduction in emission has been recorded for a 20% decrease in load.

Again, particulate emission is normally not applied to gas turbines since it uses natural gas which is a relatively clean fuel. In case distillate or other liquid fuels are used, these are treated beforehand.

2.5 Cycling ability of technologies already matured

2.5.1 Whenever generating units are turned on/ off or ramped down to low load, (or up to high load), operation, the boiler, steam lines, and turbine undergo major stress associated with changing temperatures and pressures. However the resulting wear and tear is difficult to measure as it only becomes evident during maintenance and equipment replacement. The ability to sustain this wear and tear varies for different technologies. This ability is referred to as cycling ability. This characteristic determines the ability of a technology to undergo frequent ramping without incurring much damage.

2.5.2 The impact of cycling across the technologies varies depending on specific attributes.

2.5.3 Major issues across both PC fired and CCGT units, which together constitute bulk of the utility scale thermal power technologies across the globe, are tabulated below:

TABLE 6.4: IMPACT OF CYCLING ON CONVENTIONAL THERMAL UNITS

BOILER UNIT	Turbine units	Combined Cycle units
Drum humping	Thermal fatigue and steam temperature mismatch.	Erosion/ corrosion of turbine nozzle/ vanes
Oxide scale spallation on SH and RH tubes	Steam chest distortion and fatigue induced cracking	Temperature stresses in turbine rotor
Thermally induced fatigue on economisers	Solid particle erosion of blade and nozzle block	Sintering of blade coatings
SH/ RH DMW failures	Loss of clearances and possible rotor rubs	Erosion / corrosion fatigue of combustion liner
Burner refractory failures	Increased silica and copper deposits	High stresses from uneven flows of HRSG tubes; tube failures from thermal differentials
Air heater seals degradation	Seal wear and distortion	Flow assisted corrosion of carbon steel tubes of condensate/ feed water systems
Iron wear rates increase due to low coal flow	Possibility of bearing damage.	Thermal quench of headers from untrained condensates
Supercritical furnace distortion.	Thermal stresses in feed water heaters	

2.5.4 Other coal based technologies, like CFBC technology, had been confined to captive power application till recent years; hence no published data is available about the exact impacts of cycling. However, keeping in view that for a power plant unit, since only the boiler technology is different between PF and CFBC based units, it can be fairly inferred that the cycling capability of CFBC based units, albeit marginally lower, could still be in a comparable range with PF fired units. This is applicable for supercritical CFBC units also.

2.6 Cycling ability of IGCC and UCG based CCGT

2.6.1 Though both IGCC and UCG employ gas turbines as the main power generation equipment, there are fundamental differences in the operations as follows:

i). IGCC operates in a stand-alone manner with all three major components – ASU, gasifier and cleanup as well as the power block - integrated to each other. Since ASU being the most sluggish of these, the flexibility of the IGCC unit would depend on the ramp up rate of the ASU (1- 3 %). In view of this, IGCC units are inherently not suitable for cycling.

ii). In case of UCG based units, however, since a number of UCG wells normally support a power unit, in general, a UCG based unit can operate like a combined cycle unit since the gas pooled from multiple wells can be fed to the power block. Hence in case of a UCG unit operating in a flexible mode, the typical issues associated with IGCC performance should not, *per se,* apply.

iii). However, since both the technologies use syngas fired gas turbines with fairly limited operational experience, there are a few aspects needing discussion as detailed below.

2.6.2 Gas turbines firing syngas typically require about 3 to 7 times the fuel flow to produce the same turbine inlet temperature. This, in turn, allows the turbine to produce more power, sometimes to the extent of 20%, and at times results in a higher efficiency also. However, many times, equipment restrictions like surge margin can limit the capacity.

2.6.3 Further, the higher power output cannot always be considered a boon since considerable loss in the life of the turbine components could be experienced owing to higher flame temperatures with increasing hydrogen content in syngas. Some studies have shown that a syngas with about 12% H2 content can reduce the creep life of the components by 20%. [98]

2.6.4 Gas turbines firing predominantly methane rich natural gas have been conventionally operated with premixed combustor systems that can be operated to maintain flame temperature, and thus thermal NOx, within limits over the range of operation.

2.6.5 However, increased use of syngas, in view of their heterogeneous compositions posed specific challenges as listed below:[99]

- higher flame speed
- low ignition energy
- wider flammability range
- faster combustion dynamics

2.6.6 These characteristics precluded the premix combustors owing to a number of hassles associated with such characteristics of syngas especially blow out, flashback and combustion instability.

2.6.7 Blow out essentially is a phenomenon whereby the flame becomes detached from the location where it is anchored and gets physically 'blown out' of the combustor.

2.6.8 Flash back refers to a situation where the flame propagates upstream of the region where it is supposed to anchor and into premixing passages that are not designed for high temperatures.

2.6.9 Combustion instability arises out of damaging pressure oscillations associated with wide fluctuations in the combustion heat release rate. These oscillations give rise to wear and damage to combustor components and, in extreme cases, can cause liberation of pieces into the hot gas path, with the potential to damage turbine components.

2.6.10 In view of these characteristics associated with the typical syngas, the gas turbines firing these fuels have been conventionally employing diffusion burners. Diffusion burners have however, been prone to generate higher emission.

2.6.11 In view of the known drawbacks of both the types of combustors, continuing research on syngas fired gas turbines has been focussing on hybrid combustors with the twin objectives of fuel flexibility and low NOx emission.

2.6.12 A report about the operational experience of IGCC operating at Buggenum[92] indicates that the ramp rate achieved with syngas is 1.5 MW per minute, (~ 0.5 % per minute), against 3.5 MW per minute, (~1.2 % per minute), with natural gas on a gross output of 285 MW.

2.6.13 In summary, however, it can be fairly concluded that when operating with UCG gas, the operational flexibility that can be achieved with modern CCGTs could be marginally lower than - those of CCGTs using gas.

2.7 Minimum stable load

2.7.1 In case of minimum stable load, there appears to be a closer agreement amongst various literatures [90, 100, 101, 102, 103]

2.7.2 Typically PC based units, both subcritical and supercritical, are stable down to 40%. But these are generic cases and assume fuels with average volatiles content (bituminous/ sub bituminous or lignite).E.g.: Typical Indian utilities specify a minimum of 30- 40 % stable load without oil support. This is possible in view of the fuel quality specified.

2.7.3 When the fuel quality deteriorates with volatiles, the operation window also gets narrowed i.e., the minimum stable load which the boiler can sustain goes up. On the other extreme, with anthracite coals, the typical boiler minimum stable load is around 60%.

2.7.4 There are some literature which states some subcritical PC units with the ability to back down to 10 % load[90]; however no details could be made available. Further, some subcritical plants have been specifically customised to operate down to 20% of rated load[121]; however, here again, what kind of modifications and at what costs this flexibility has been attained is not made known.

2.7.5 No detailed data on utility level CFBC boilers are available; however, an 800 MWe supercritical boiler that was recently modelled has figured out about 32% load as the threshold lower limit.

2.7.6 Between PC and CFBC technologies, when the fuel quality deteriorates, CFBC boilers have a marginal advantage over PC with the former able to sustain a marginally lower load compared to the latter. However, the practical significance of this advantage will be felt only for fuels with very low volatiles for sustained operations.

2.7.7 In respect of coal based units, however, taking into consideration the broader range of unit load while designing the core components like furnace and combustion controls has been found to improve the lower load range.

2.7.8 For CCGT, the minimum stable load is around 25%.

2.7.9 In case of OCGTs, the technical minimum load is 10%, though from an emission standpoint, around 40% is the threshold.

2.7.10 IGCCs are typically meant for base load operation in view of the low ramping gradient. Besides, below 60%, CO formation gets exacerbated. However, the technical minimum load is 50%.

2.7.11 Since UCG based GTs are also operating with syngas, it can be inferred that these will have similar performance features like IGCC in respect of the minimum load.

2.7.12 As mentioned earlier, attempts have been ongoing by way of R&D effort to lower the start up times of both coal based technologies and CCGTs in order to make these more compatible with flexible operating regimes.

2.8 An Illustrative example for increased fuel consumption on account of heat rate increase due to part load operation during cycling for a coal based unit:

2.8.1 The following example illustrates the increase in the unit fuel consumption for a unit operating on cyclic load, when compared with another unit operating on base load.

Base : 2 x 660 MW
Station heat rate : 2100 kCal/ kWh
Coal GCV : 3500 kcal/ kg

TABLE 6.5 : ILLUSTRATION OF HEAT RATE IMPACT ON CYCLING UNITS

Sl. No.		CASE A : NORMAL BASE LOAD OPERATION	CASE B: CYCLIC OPERATION
1	Annual Operation hours		
	At 100% load	6000	1000
	At 80% load	-	2000
	At 60% load	-	3000
2	Increase in fuel consumption, Tons	Base	120 000
3	Increase in fuel consumption, %	Base	2.5%

2.8.2 It can be seen that the aggregate fuel cost per unit increases by 2.5%.

2.9 Projected Aggregate cost of cycling:

2.9.1 As mentioned earlier, the aggregate cost of cycling of a thermal power unit is the sum of:

i). The increase in fixed cost on account of lower off take.

ii). O&M cost on account of equipment damage during cyclic operation.

iii). Increase in the start up fuel, (proportional to number of starts) and miscellaneous cost (chemicals/ lube / additive etc).

2.9.2 While the direct incremental fixed cost of capital is easy to estimate, it is difficult to estimate cost attributable to the incremental damage of the power plant equipment and consequent downtime due to cyclic operation; while this has been recognised by the utility industry for long, not much had been done to ascertain the cost attributable to cycling.

2.9.3 The main roadblock was the difficulty in segregating the costs associated with wear and tear and outages associated with normal operation and that which can be attributed solely to cycling.

2.9.4 The first major attempt in this direction was made by national renewable energy laboratory (NREL) and Western Electricity Coordinating Council(WECC) of the US when they commissioned Intertech Aptech for a comprehensive study.[104,105,106]

2.9.5 The findings of their study, covering numerous plants between 1982 and 2003 in the US, have brought out that the cost of cycling the power plant varies widely in view of the multiplicity of factors involved in design, operation, mid-way uprating, add-on hard-ware, sensitivity of control systems, ramp up rates etc.

2.9.6 However, with a basic set of assumptions, they have arrived at a matrix an extract of which is reproduced in the following table.

TABLE 6.6: CAPITAL AND MAINTENANCE COSTS ASSOCIATED WITH CYCLING

Sl No.	Regime	Annual costs, Capital and maintenance $US / MWh		
		Coal fired small	Coal fired large (Sub &Supercritical)	Combined Cycle units
1	Cold start	147	104 - 105	79
2	Warm start	157	64-65	55
3	Hot start	94	54-59	35

Note: Listed are Median values.

2.9.7 Cost of start up fuel and chemicals, additives etc. have also been separately tabulated for each technology and operating regime.

2.9.8 Based on the values given above, an attempt has been made to determine the incremental annual cost of cycling for a 1000 MW plant in the Indian context under the following two possible cycling scenarios and compare them with the base line case (without cycling)

- Case 1: weekend shutdown
- Case 2: Daily cycling

2.9.9 In applying the method employed by Intertech Aptech to Indian conditions, the following factors have been given consideration:

i). Relatively lower operating skills sets in India: this will have the potential to increase the cost of cycling.

ii). Based on the current benchmarks, the typical O&M cost of a plant in the US is almost double in respect of coal based units; in case of CCGTs, however, the O&M cost in India is significantly higher. This apparent paradox can be explained as follows:

In case of coal based plants, in respect of India, cost of manpower constitutes a significant portion and hence lower manpower cost in India could be one of the reasons for lower O&M costs. Besides, in case of coal based units, the bulk of the equipment outside the power block is sourced from Indian vendors with its attendant cost advantages.

In case of CCGT units, however, the equipment outside the power block is marginal; besides, CCGT operation typically requires less than a third of the manpower as compared to an identically sized PF unit. Hence the bulk of the O&M cost in case of Indian CCGT is attributable to cost of spares for CCGT equipments which are imported. This is the reason for the relatively higher O&M costs for CCGTs in India

2.9.10 On the basis of the above, the following input matrix has been considered in arriving at a possible 'cost range' in the Indian context.

TABLE6.7: ESTIMATED CYCLING COST FACTORS FOR INDIAN THERMAL UNITS

Sl No.	Regime	Annual costs, Capital and maintenance $US / MWh		
		Coal fired 1000 MW		Combined Cycle units 1000 MW
		Daily cycling	Weekend shutdown	
1	cold start	100	100	90
2	warm start	60	80	60
3	Hot	50	50	40

2.9.11 The higher cost factor considered in respect of a 'warm start' regime for weekend shutdown is keeping in view the longer start up time required for a weekend shutdown unit, though technically cold start does not apply.

2.9.12 Further, the fuel cost has been considered with typical ruling values in respect of

i). Domestic coal with Rs 1200/ ton (for 3500 kCal GCV) as the lower-bound

ii).Imported coal with Rs 6000/ ton (for 5500 kCal GCV) as the upper-bound. These figures have been considered because the fuel cost for typical coal based plants in India falls within this range. An average loading of 70% has been considered for determining the PLF and in turn unit cost of capital. Cost of capital has been considered as Re 1/- for PF units and Rs 0.9/- for CCGT units uniformly for base load case.

2.9.13 In case of CCGTs, gas prices of $US8 and $US16/ MMBTU have been considered as lower and upper bound costs with an exchange rate of Rs 60/ $US.

2.9.14 The results are shown in chart 6.4below

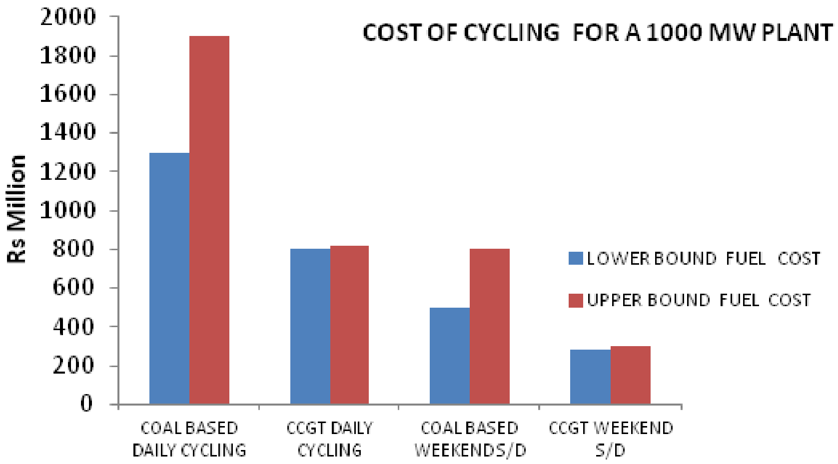

CHART 6.4: COST OF CYCLING FOR A 1000 MW UNIT

2.9.15 The chart 6.4shows that :

i). The cycling cost of a plant on daily cycling is more than twice the cost of a plant of an identical size which is on weekend shutdown.

ii). In case of CCGTs, fuel cost does not appear to have any major influence. This is logical owing to the far lower start up times associated with CCGT units.

2.9.16 A primary comparison of the net generation cost for the three cases, i.e. base load, weekend shutdown and daily cycling, with the current cost levels for Indian plants are presented in the following charts (Charts 6.5& 6.6)

2.9.17 These charts give an overview of cycling costs per unit of electricity generation set off against the cost of base load operation across two variants: type of cycling (daily cycling/ weekend shut down, fuel costs (lower and upper bound).

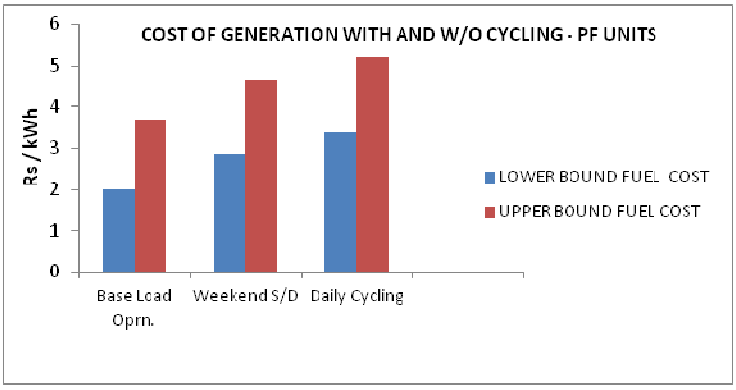

CHART 6.5: AGGREGATE GEN COST. WITH AND W/O CYCLING – PF UNITS

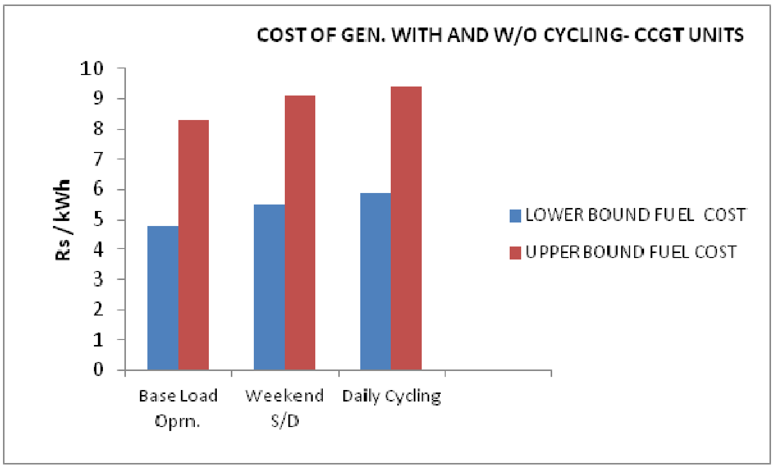

CHART 6.6: AGGREGATE GEN COST. WITH AND W/O CYCLING – CCGT UNITS

2.9.18 The generation cost has been determined on a comparative basis summing up:

i). The cost of cycling for the given operating regime.

ii). O&M cost for the base load case

iii). Fixed cost of capital, proportioned based on the annual operating hours for the respective operating regimes.

iv). Fuel cost of generation.

2.9.19 It can be observed from the above charts that as the fuel price increases, the proportional increase in the generation cost is getting narrowed down: E.g.: For the lower bound fuel cost for PF, while the generation cost increases by about 70% (i.e. from Rs 2.0 to Rs 3.4) in case of daily cycling, the corresponding increase for the upper bound fuel cost is only 40% (from Rs 3.7 to Rs 5.2).

2.9.20 The following charts give the impacts of cycling cost without considering the cost of capital for the corresponding cases.

2.9.21 The figures depicted in the charts 6.7 and 6.8 reflect the range of cost on account of cycling along with variable fuel cost without the cost of capital (investment). Since typical cycling plants operate on market arbitrage, the unit cost of capital will be relatively high as compared to base load units and thus is factored separately. The figures depicted in these two charts need to be seen from this perspective.

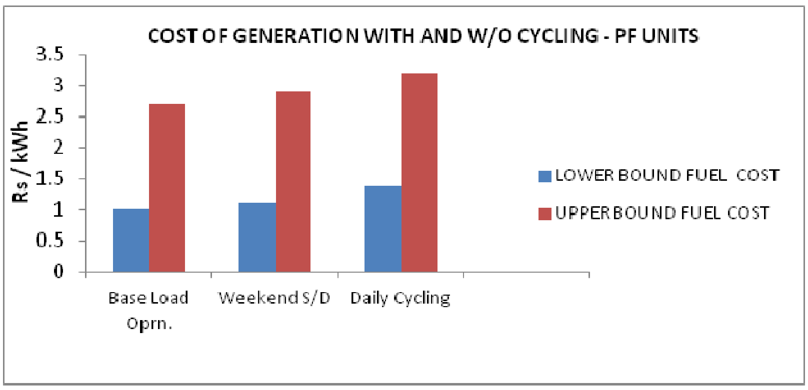

CHART 6.7: GEN COST. EXCLUSIVE OF COST OF CAPITAL – PF UNITS

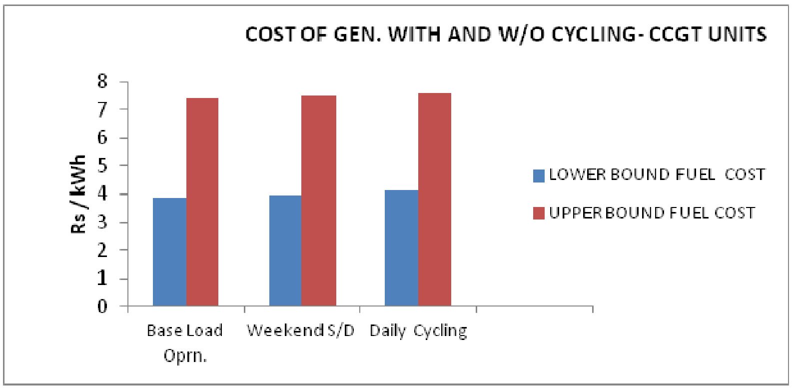

CHART 6.8: GEN COST. EXCLUSIVE OF COST OF CAPITAL – CCGT UNITS

2.9.22 As mentioned earlier, the cost figures presented above have been worked out based on the method described earlier and the actual cost could vastly vary for a given plant depending on a number of factors. It is pertinent to mention here that between the US and Europe, there are vast differences in the O&M costs for base load plants (typical coal and CCGT O&M costs in EU are almost double when compared to US).

2.9.23 In summary, therefore, the costs projected for cycling above need to be considered only on an order-of magnitude basis.

2.10 Cycling cost of IGCC units:

2.10.1 Looking at the general attributes of the technology, IGCCs are expected to operate only on base load and is not suitable for cycling.

2.10.2 Further, presumably, with their low population across the globe and the very low ramp up rates from some of the units, no attempt has been made to ascertain cycling costs associated with these units.

2.10.3 Though in case of PF units, the cycling costs can be co-related as multiples of base load O&M costs, the same may not be a rational approach in case of IGCCS. This is in view of the significant number of major subsystems forming a typical IGCC-ASU, gasifier, clean up system and power block consisting of gas turbine, steam turbine and steam generator, each of which has individual dynamic characteristics and costs associated with ramping up and down.(as against a PF unit which has only two major subsystems–boiler and turbine islands. E.g.: when the ramp down is more than the system can tolerate, the gasifier will call for venting with its attendant costs. However, collectively as a unit how the cost varies with cycling is something which can be determined only by prototype testing on a number of units before a common trend can be drawn up.

2.10.4 A specific point to be noted in this connection is that though the median ramp up rate on IGCC units mentioned across various literatures varies from 1 to 3 % per minute, as per the operational data published by US NETL, the ramp rate of IGCC Buggenum is 1.5 MW per minute[92] which is close to 0.5% per minute. What this shows is that the dynamic characteristics of IGCC units needs further study before a realistic assessment of the associated cost of cycling can be made.

2.11 Flexible Operation: Indian Context

2.11.1 Looking at the Indian context, a few conclusions that can be drawn are:
i). The Indian grid is going to be fed predominantly by PF units from the thermal side for the medium term with possibly minor backing from CFBC technology.

ii). Technologies like supercritical CFBC, IGCC may take some time to get ushered into India.
iii). Further, for the medium term, it is very unlikely that any major CCGT / OCGT units will come on line.
iii). For the operational flexibility of PF to improve, additional hardware and software may have to be introduced.
iv). However, since flexible operation of the thermal units effectively implies running the units on cycling, as shown in the foregoing paragraphs, significant escalation in the generation cost on account of higher cost of capital(apart from incremental cost of cycling) will occur. This will obviously call for rejigging the tariff.

3.0 FLEXIBLE GENERATION WITH COMBINED HEAT AND POWER.

3.1 Technically, flexibility in power generation is possible with combined heat and power units. The following methods can be normally employed.

3.1.1 Using a backpressure turbine
3.1.2 Using extraction cum condensing turbine
3.1.3 Using steam extraction from a steam turbine connected to CCGT units

3.2 While all these alternatives are technically feasible, in practical terms, unless there is an adequate scale for the heat to be exported, the viability could be a question. The reasons can be explained as follows:

3.3 The internal efficiency of a typical 30 MW unit (for cogeneration application), would be 78- 82% for the high pressure stage side and 82- 86% for the intermediate stage, whereas the corresponding figures for a 500 MW will be 88 - 90% and 90 - 92%, implying corresponding increase in the steam requirement.

3.4 If such a cogen unit is to be used for facilitating flexible generation, then steam export has to offset the reduction in the efficiency for the smaller set. It has been found that such units can reach the efficiency of larger units only if the heating demand is substantial, i.e., at least 20% of the throttle steam flow.

3.5 Since a typical 30 MW unit working solely on power requires about 110 TPH of steam, the cogeneration will be efficient only if about 25 TPH of steam is exported.

3.6 It can be found that the heating requirement of a typical industry application is far lower than this quantum (around 2- 5 TPH of equivalent steam in bulk of the cases); since steam export beyond a certain distance results in both pressure and temperature drops, it is a case of multiple energy loss and hence beyond some threshold, the energy tax becomes significant. Therefore it will require a cluster of industrial units nearby for absorbing the given quantum of steam.

3.7 On the other hand, if the steam is to be used for industrial air-conditioning applications, 25 TPH steam usage will require 5000 TR refrigeration requirement; the applications of such magnitude are far and few.

3.8 In case of still smaller sets, the turbine efficiency falls further, entailing more and more steam export requirement in order to increase the overall efficiency. Further, with smaller units, the auxiliary consumption also shoots up lowering the overall net efficiency. E.g.: For a 30 MW unit, the auxiliary power consumption will be about 10- 12%,i.e. 100% more than a large unit.

3.9 A similar case holds good for backpressure turbines also.

3.10 In the context, it is pertinent to mention that in western countries with cold climates, district heating and air-conditioning together is a perennial application of CHP and hence can support flexible generation; in India, district heating concept would not suit in view of the tropical climate in most parts of the country. As for CHP for industrial application, it may be possible only with new industrial clusters with planned generator-users located within close proximity.

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Section VII
General Aspects Related To Thermal Power Generation

1.0 INTRODUCTION:

1.1 Keeping in view the attributes of the various technologies covered in earlier sections, an attempt is made herein to bring out some of the contextual aspects which can sway the technology selection.

2.0 EMISSION FROM THERMAL POWER PLANTS

2.1 One of the primary aspects which drove the advanced economies to embrace cleaner technologies was the progressive stringency in emission norms. Such policy actions have also contributed to propelling the OEMs in chasing the next milestones in both efficiency and environmental parameters.

2.2 In advanced economies, the development of CBFC technology from mid-size units to the frontline of the utility power generation has happened because of the tightening of NOx and SOx norms. Of late, it has been observed that this technology is trying to breach the unit size and technology barriers and environmentally sensitive regions are seen embracing this technology.

2.3 Nowadays, power utilities in some western countries find it economical to adopt CFBC based units without any end-of-pipe augmentations for SOx and NOx control for meeting the local environmental norms, which otherwise would need PC units fitted with FGD and De-NOx systems.

2.4 Similar is the case with IGCC. With all its known drawbacks, reliability and poorer grid characteristics, it has been recognised as one of the most environmentally friendly technologies. As described earlier, in view of its inherent environment friendly attributes, research has been going on across the globe in both basic technology upgradation and component/sub-system improvement in order to make it economically sustainable.

2.5 During the past several years, India has been adding significant power generation capacity, mostly in the thermal sector and consequently, the emissions from power plants have been rising. This, though perhaps, is not immediately apparent, will have a long term impact on the environment and the spin off effects are going to affect local and surrounding habitation, water quality as well as flora and fauna.

2.6 As of now, the atmospheric emission norms in India appear to be far less stringent in relation to many major economies. In fact, environmental compliance in India has been considered as 'low hanging fruit' by utility developers.

2.7 Even China, which has a thermal power capacity more than 4 times that of India, has recast the emission limits from thermal stations in 2012, making them comparable to advanced economies of the west.

2.8 One of the reasons as to why emission friendly technologies are not adopted in India is because it is possible to meet the current norms with least cost thermal technologies.

2.9 A broad comparison of the power plant emission limits from overseas power stations along with the current norms prevailing in India is tabulated below.[107,108,109]

TABLE 7.1 : COMPARATIVE EMISSION LIMITS OF MAJOR ECONOMIES

PARAMETER (mg/Nm3)	US	EU	China	India
NOx	117	200(after 2015)	100	- (actual 300- 500)
SOx	160	15- 200	100	- (actual ~ 1000)
Particulates	22.5	30 - 50 (100 for lignite)	20 - 30	150*
Mercury	0.001	0.03	0.03	-

* Many large stations are following 50 mg/ Nm^3

2.10 The stark difference between Indian norms and those of the other three major economies is apparent from the above

2.11 **De- NOxing** :The conventional methods of reducing NOx for PF units is selective catalytic reduction (SCR).Upto 80% reduction can be achieved.

- The cost for large units could be in the vicinity of $ 150 – 200 / kW. Besides, there will be an energy penalty of 1 to 1.5%. The O&M cost for NOx is estimated to be about 5% of the cost of electricity.[110]

2.12 **Flue gas de-sulphurisation** (FGD): There are a number of methods of reducing the SOx from pulverised fuel fired units. If plants are in coastal areas, the economical method is to use sea water. Otherwise lime(wet or dry) can be employed.

- The Capex for FGD is expected to be around $200 – 300/ kW. Besides, the energy penalty ranging from 1 to 1.5%, the O&M cost will also be about 10% of the cost of electricity.[110]

2.13 **Particulate matter**: At present, Indian units employ ESPs for capturing SPM; ESPs can be used for bringing the SPM down to ~ 30 ppm. Below this, it will require bag filters. Bag filters, though of marginal Capex, do put a tax on maintenance apart from the energy penalty by way of increased head on the ID fan. The energy penalty on a 1000 MW unit may be approximately 1 MW- 1.5 MW. However, the maintenance cost of a bag filter depends on coal quality and cannot be generically estimated.

2.14 **Mercury**: India is considered one of the world's most mercury emitting countries, as per a report quoting recent negotiations with UN on this aspect. Coal burning releases mercury into the air. When the metal gets into the atmosphere, it is absorbed by water, plants and animals, exposing humans to potential nerve and brain damage as well as heart disease and other complications.

2.15 IGCC is one of the best technologies which can capture mercury from coal.

3.0 FUEL AVAILABILITY – PROJECTIONS AND CHALLENGES:

3.1 As per projections given by MoP for the 12th plan period, with all inputs considered, India will require ~160 MT additional import of coal (apart from coal required for imported coal fired plants). However, this is based on 9% GDP growth and BAU scenarios. Since the growth has come down during the last two years and is not expected to pick up in the short term, perhaps a more conservative target of 100 – 120 MT import could be a more realistic scenario, (keeping in view status quo on gas availability and only meeting part of RE targets), that too in the latter half of the 12th plan. [28]

3.2 Now to put some numbers in perspective, 100 MT import of coal may cost anywhere between Rs 650 to 750 billion and, together with other forms of energy (oil and LNG), is going to bloat the imported energy basket and in turn significantly escalate the CAD.

3.3 Domestic Coal Vs Imported Coal-Primary Comparison: A primary comparison of domestic and imported coals is tabulated below:

TABLE 7.2: DOMESTIC AND IMPORTED COAL – A PRIMARY COMPARISON

Sl. No.	DESCRIPTION	DOMESTIC COAL	IMPORTED COAL
1	GCV	3500 - 4000	5000 - 6000
2	Moisture	8- 20	6 – 12
3	Ash	35 - 45	6- 10
4	Sulphur	0.3- 0.5	0.6- 0.8
5	Ash chemistry	Varies	
6	Boiler efficiency	0.85- 0.87	0.89- 0.91
7	Auxiliary power consumption	5 - 5.5	4.5 - 5
8	Plant Investment Cost	Base	5% less* (Only order-of-magnitude since Imported plants are normally located in coastal areas and hence cost heads are different)

3.4 Imported coal - price trends: The typical price variation of imported coal (FOB basis), along with the exchange rate variation of Indian Rupee Vs US Dollar during the past few years are shown by way of the following chart.

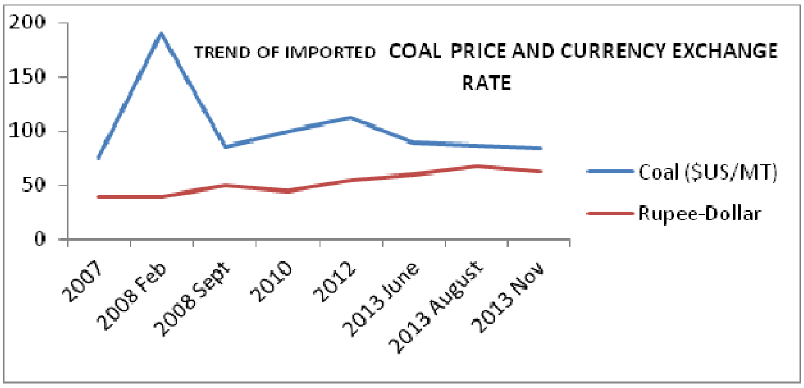

CHART 7.1 : PRICE TREND OF IMPORTED COAL DURING RECENT PAST

3.5 The sensitivity of the imported coal to both the international demand –supply as well as the relative strength of the Indian Currency from time to time can be seen from the chart.

4.0 IMPORTED COAL WITH HIGH SULPHUR

4.1 The sulphur content in typical Indian coal is fairly low in relation to some of the overseas coal. While Indian coal has a median sulphur content between 0.3 and 0.4% and rarely exceeds 1%, some overseas coal (e.g.: coal in eastern region of the US) has sulphur content up to 3%.

4.2 The sulphur content in the coal has many impacts both on the boiler design and environment.

4.3 Sulphur content in the coal, in combination with air and moisture forms sulphuric acid which has potential to corrode when condensed. This can eventually lead to rupture of boiler tubes. Hence, normally, the boiler exit temperature is designed in line with the sulphur content in the coal. An extreme case is petcoke or some lignite variety wherein sulphur content can vary from 4 to 8%. Most of the petcoke fired units are designed with boiler exit temperature of around 180^0C. This obviously has an impact on the boiler efficiency.

4.4 A 10 °C increase in boiler exit temperature will call for an additional 20000 Tons of coal per annum for a 2 x 660 MW unit.

4.5 Besides, higher sulphur content can also increase the corrosion at burner belt areas in the presence of CO (owing to lower air fuel ratio).

4.6 Further, since sulphur oxides are harmful to health, beyond a threshold, it will call for de-sulphurisation of flue gas which is expensive, especially for Indian cost levels of power plant equipment. However, FGD will be required only for pulverised fuel firing. In case of CFBC, the technology facilitates capture of sulphur by injection of sorbents in the bed.

4.7 Imported coals, in view of their low ash loading will also have better performance with entrained flow gasifiers in IGCC technology.

4.8 It is necessary in the context to mention that an imported coal with say 0.6% sulphur will have almost identical impact on both boiler performance and environment as compared to a domestic coal having a sulphur content of 0.3%. This is because of the typically higher GCV associated with imported coal.

4.9 However, sulphur content has a small positive impact on the design of ESP since sulphur content induces better migration of flue gas particulate matter to collecting electrodes of the ESP.

4.10 At the same time, as a practical measure, Indian utilities normally put a cap on sulphur content in the coal being imported to India in order to avert the hassles associated with higher than threshold sulphur content both on the equipment and the environment.

5.0 INFRASTRUCTURAL REQUIREMENTS

5.1 General:

5.1.1 Apart from fuel, the other two major impediments coming in the way of development of coal based power plants in India are availability of free-hold contiguous land and adequate water. Earlier, there were instances of land being acquired in an arbitrary manner without regard to the realistic need for a specific project and this had led to political and social issues.

5.1.2 Similarly, in case of water, it was found that power plants were using far more than their need of water, which was released to them at concessional rates, which resulted in wastage.

5.1.3 In view of this, CEA had constituted a body to examine and advise the rational requirement of land and water[111]. The following norms have been suggested by the committee.

TABLE 7.3: LAND AND WATER REQUIREMENT FOR CONVENTIONAL COAL BASED UNITS

	DOMESTIC COAL BASED		IMPORTED COAL BASED	
	2 X 500 MW	5 X 800 MW	3 X 660	5 X 800
LAND ACRE/ MW	1.42	0.69	0.42	0.38
WATER, M3/ hr per 1000 MW	2850 - 2900			

5.1.4 From the above, it can be seen that for generation of about 40 GW with domestic coal (about 2/3rd of the 13th Plan target for thermal), it will require about 800 million m^3 of additional consumptive water per annum.

6.0 CCS TECHNOLOGIES

6.1 Need:

6.1.1 Based on a report prepared by the MOEF in 2009, citing four studies undertaken, India is projected to take another 15 years or so to reach the global average in CO2 emission, conservatively.[112]

6.1.2 Hence at this stage, even if for argument sake, India decides to install CCS on all new power plants, that alone will require, conservatively, more than 5% of India's annual budget for the next few years.

6.1.3 India has already been progressing on energy efficiency improvements, DSM and reduction in AT & C losses. These measures are expected to offset the increase in per capita energy consumption expected in the coming years.

6.2 Affordability:

6.2.1 Electricity as a commodity is extremely price sensitive in India. Hence going for CCS will eventually undercut the country's aim for providing affordable electricity to citizens.

7.0 ADVANCED USC UNITS AND IGCC – EXTERNALITIES IN COST MATRIX.

7.1.1 As described earlier, A-USC technology had been conceived with the twin objective of climbing up the energy efficiency ladder and reducing the carbon foot print very substantially.

7.1.2 This section tries to look at some externalities which can have a major influence on the cost-economics of these units for India.

7.1.3 Since A-USC units appear to be still evolving even for demonstration, the first part dwells on this.

7.1.4 It can be seen that there are significant amounts of Nickel based alloys and austenite. Raw nickel itself is about 30- 40 times more expensive compared to steel.

7.1.5 The material quantity requirement for the A-USC fleet is expected to far offset the gain by reduced steam flow per MW. The reasons are multi-fold:

- Lower temperature difference between flue gas and steam necessitates a larger surface.
- Higher pressure/temperature of steam will demand higher thickness of material.

7.1.6 In fact, for 750 -760 °C region only very few materials have been developed; besides, as already stated earlier, a few shortlisted earlier have later been discarded for want of compatibility.

7.1.7 At this point, there is a need to look at it from another perspective: The global demand –supply scenario for Nickel base alloys.

7.1.8 The main constituents of these alloys and their market positions are tabulated below:

TABLE 7.4 : INDUSTRIAL METAL PRODUCTION DATA

Sl. No.	Metal	Current annual production, Tons	Major countries where produced
2	Nickel	1600 000	50% by China, Russia and japan
3	Cobalt	70 000	70% by China, Russia &DRC
4	Tungsten	60 000	> 80% by China
5	Molybdenum	240 000	80% by China, US ,Chile
6	Niobium	60000	99% by Brazil and Canada

7.1.9 The following chart gives the trend of prices for these metals during the past years.

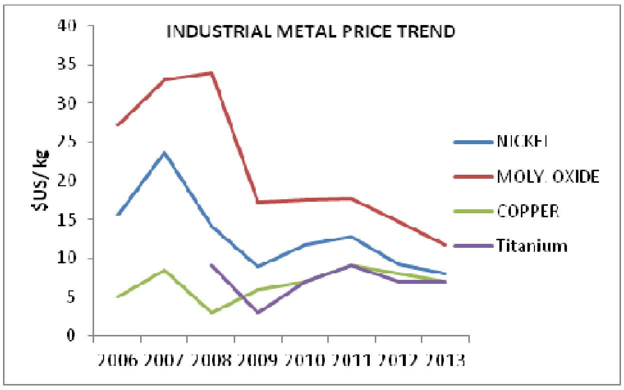

CHART 7.2: PRICE TREND OF INDUSTRIAL METALS IN RECENT PAST

7.1.10 It can be observed that the prices had peaked during 2006- 2008 period, i.e., just before global recession started; this period was one of the crests in global industrial activity pushing all commodity prices including fuels sky high.

7.1.11 Further, from the table, it is clear that many of these expensive metals are produced in a few countries with strong political and economic power and hence have the potential to tilt market dynamics at will if the opportunity presents itself.

7.1.12 The approximate weight of the superheater and reheater in a 660 MW boiler for a 250/ 540/ 568 cycle is 4000 tonnes.

7.1.13 For an A-USC unit of 800 MW, 350 bar700 °C cycle, approximate tonnage requirement of Nickel alloys and austenites including turbine components could be anywhere in the region of 2000 tonnes.

7.1.14 As per one of the reports, the projected cost of this, (as part of the boiler-ST), from OEMs could be in the region of Rs 1500- 2000 crores.

7.1.15 A study modelled on a 750 MW plant in the US[15] found that

- When compared to a conventional SC unit, the A-USC boiler will be about 20% narrower, while at the same time, will have 7% more suspended weight.
- Overall weight increase will be about 13%.
- Overall incremental cost for the A-USC boiler was about 28%.

7.1.16 However, the cost bearing factors are significantly different between the US and India. If the technology is to be imported, issues like first of a kind cost factors will arise.

7.1.17 Since China has also been ramping up efforts to harness the A-USC technology, the demand from China for Nickel based superalloys are expected to rise for sometime.

7.1.18 Japan also, after the Fukushima incident, is reportedly mulling over a few options including one scenario where nuclear energy is to be jettisoned altogether, in which case, their dependence on thermal energy will increase.[113]

7.1.19 Since Nickel based alloys are universally used in gas turbines, increase in gas turbine demand also is expected to have a concurrent increase in demand of nickel based superalloys. It is also necessary to note that in the thermal sector, since gas is the current favourite across the globe after the shale gas revolution, frantic development is going on to increase the firing temperature from the current attained 1600 °C to 1700 °C; this is also expected to escalate the demand for superalloys based on Nickel.

7.1.20 Availability of vendors: Though globally, there are more than half a dozen vendors who are capable of manufacturing USC level boilers and turbines, only a couple of them, who are willing to take huge market risks with the uncertainties expected of such a niche technology, are expected to move seriously into the A-USC regime. This again will have a major bearing on the potential Capex associated with adopting this technology.

- The net impact of the aspects discussed above: Likely increase in cost.

7.1.21 Risks perceived by overseas prime vendors for long gestation projects of FOAK in India:

i). A case in point is APGENCO Vijayawada, where, a decade earlier, the proposal to build India's first supercritical thermal plant was taken forward. Though in the concept stage it was thought that the increase in the cost, (with subcritical as the base), would be about 15- 20%, when the bids were opened (i.e. after going through the whole process of basic engineering and bidding process with the involvement of two overseas consultants and an overseas lender), it revealed an increase to the tune of about 30%; with that level of costing at that time, it was found economically unviable and consequently the project was shelved. The case showed the cost of migration to the new technology significantly dependent on overseas prime vendors, and the cost uncertainties associated with first-of- a- kind (FOAK) projects.

ii). Three years ago, two large gas based projects were discontinued after award was placed on overseas contractors.

iii). Second is the stability of the economy especially the movement of currency. After a relatively stable phase between 2007 and 2012, (barring the global recession which lasted 8 to 10 months in between), Indian currency has been in a more volatile region for some time now; with the twin developments of low growth coupled with high cost of imported energy prices (oil & gas), it is expected to remain that way. It is understood that overseas vendors,(mostly from advanced economies), normally factor in, amongst others, what is called 'country risk' while quoting for projects with longer duration.

- Impact: Likely increase in cost.

7.1.22 In the US, which was building a lot of IGCCs, it is perceived that there may not be any major coal based plants in the medium term (up to 2025 as per US EPA's prediction). Though the gasification technology chain is not totally confined to coal, large IGCC plants were being planned with coal. This has happened partly in view of the surge in the availability of natural gas for power generation. Similar is the case with Canada where the demands for coal based plants are reportedly on the wane. An immediate reflection of this slack can be seen in the export price of US coal which had been on the downward slope for more than an year.

- Impact: Likely slackening in cost.

7.1.23 Movement on Nuclear power in Japan and Europe: No clear signs are emerging about the (immediate) future of nuclear power in Japan and in some European countries. Depending on which way the wind moves this also will have some impact on the cost of IGCC equipment.

- Impact: Either way.

7.1.24 A number of IGCCs are planned in neighbouring countries like China which may facilitate drop in the cost of gasification technology; further, due to shift to cleaner fuels like natural gas in countries like the US which produce components for gasification, there is a possibility of a drop in the component prices; however, this is a doubled edged scenario. The pace at which China ramps up its capability in localisation of IGCC components can also influence the market.

- Impact: either way.

7.1.25 In summary, giving weightage to the various points discussed the overall picture most likely will be increase in the cost of A-USC units more than the estimate based on current metal prices and not much thaw in IGCC costs from where these are today.

8.0 AVAILABILITY/ RELIABILITY AND MAINTENANCE ASPECTS

8.1 Power plant availability:

8.1.1 Both the Availability, (total available hours – sum of planned and forced outages), and Reliability, (total available hours – forced outage), of power plants have been rising steadily in view of the modern tools available for on-line diagnostics and corrective action.

8.1.2 The improvements in availability along with reduction in the forced outage of Indian thermal plants[114] are shown below:

CHART 7.3 : AVAILABILITY TREND IN INDIAN THERMAL POWER STATIONS

8.1.3 It can be seen that the forced outage which was close to 20% in early 1990s had dropped below 10% by 2010.

8.1.4 A comparison from some typical overseas plants [115]indicates following values for the forced outage:

TABLE 7.5: TYPICAL FORCED OUTAGE RATES FOR THERMAL UNITS

Sl. No	Description	Equivalent forced outage rate, %
1	Coal based	6-10
2	Combined Cycle	5-8

8.1.5 As per another report [34], on a study of US power plants, the equivalent availability figures for Coal based plants are given as under:

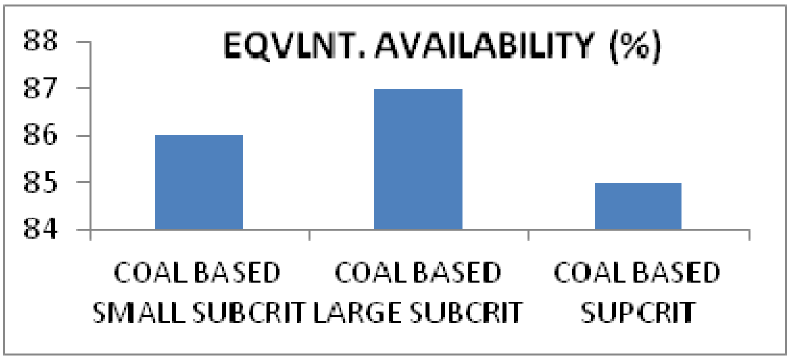

CHART 7.4: EQUIVALENT AVAIALBILITY OF COAL BASED UNITS

8.1.6 It can be inferred that the sense of figures tabulated in both the table and the chart are in an almost identical range.

8.1.7 It may be pertinent here to mention that though the US had been a pioneer in ushering supercritical technology, after a plethora of failures experienced in the early units, they had gone back to subcritical units until the recent past and hence the experience of US utilities with modern supercritical units has been fairly nascent. This possibly has got reflected in the figures depicted in the above chart.

8.1.8 Another inference from the table is that generally the forced outages of combined cycle units are lower as compared to coal based units. The main reason is that combined cycle units use cleaner fuel like natural gas and hence the outage on account of erosion or corrosion from flue gas for the steam cycle is far lower as compared to coal fired ones where boiler tube leakage is one of the major failure fronts.

8.1.9 Further, the chart shows marginally lower availability for supercritical units; this is because of the lower population of modern supercritical units in the US. With the increasing population of supercritical units in India, it is expected that the availability of supercritical units will be in close range with those of subcritical units in the short term itself.

8.1.10 Documented data regarding availability or forced outage figures for utility size CFBC boilers is not available perhaps because their population has increased only during the past decade onwards.

8.2 Measures to improve thermal power plant availability.

8.2.1 From the breakdown maintenance employed in early days, the maintenance methods have evolved through Preventive, Predictive and Performance driven maintenance practices.

8.2.2 While the breakdown maintenance mode is nowadays almost obsolete in power plants, in modern thermal power stations comprising multiple units of large unit sizes, even preventive maintenance practices have given way to Predictive maintenance practices. Of late, modern units use a combination of predictive and performance driven maintenance in order to optimise between cost of maintenance and availability.

8.2.3 The core of most power plant predictive maintenance (PdM)programs are:

i). Vibration analysis
ii). Thermography
iii).Ultrasonic analysis
iv).Oil analysis and lubrication
v). Root cause analysis.

8.2.4 Many of the above have found traction in Indian thermal plants also. While earlier, the smaller unit and station sizes acted as barriers in adopting some of the above techniques, the increasing unit and station sizes have made the benefit to cost attractive for deployment of state-of-the art maintenance facilities, hardware and software, to Indian thermal plants. Besides, complexity associated with technologies, large size supercritical coal based units and advanced class gas turbines, make it imperative to have compatible maintenance systems for ensuring optimum availability.

8.2.5 Performance-driven maintenance [116]is a targeted preventive maintenance program aimed at optimising the cost associated with maintenance. Based on past experience, specific equipment is targeted for inspection and testing and maintenance carried out based on the test results.

8.3 Technology Comparison on availability and maintenance aspects

8.3.1 From the dissection made above, it can be seen that by and large, the availability of matured technologies like pulverised fired coal based units as well as combined cycle units are in close range.

8.3.2 As for CFBC units, since till recently the population of these was confined to mid-size or were used more for captive application, or for utilising waste fuels like RDF or washery middlings, the availability of these units cannot be compared to PF based units. In India, as described earlier, the availability of CFBC for both utility power as well as large size captive power has not been encouraging on account of failures on multiple fronts in a sustained manner; however, it appears that this is more to do with the hassles associated with a particular variant of the technology.

8.3.3 Relatively lower availability of IGCC units, as discussed earlier, has been one of the Achilles' heels of this technology, which so far prevented it from becoming a frontier mode of power generation.

8.4 Cost of maintenance for Different technologies:

8.4.1 As per practice followed globally, the cost of operation and maintenance is clubbed together; most advanced economies split this into two heads:
i). A fixed component expressed per kW(or MW) year
ii). A variable component expressed per kWh(or MWh)

8.4.2 The rationale for such a practice is that unlike India, where most utility plants operate on base load, in western economies, in view of the large population of power plants and the commoditised nature of electricity, many plants operate for significantly low PLF and hence the need to split into fixed, (cost of being in the business), and variable, (cost of running the business) components.

8.4.3 For comparison sake, the cost estimates prepared by Black & Veach for US Power plants [117]in 2012 along with the O&M cost stipulated by CERC for 2014- 2019 period[118]are tabulated below. (All costs reduced to per kWh basis for clarity)

TABLE 7.6: COMPARISON OF O&M COST ACROSS TECHNOLOGIES

Sl. No.	TECHNOLOGY	O&M COST PER KWH		REMARKS
		BLACK & VEACH	CERC	1. The split up cost considered by B&V has been consolidated considering a PLF of 85% and an exchange rate of Rs 60 per $US. 2. CERC cost has been based on rate stipulated for unit sizes 600 MW and above.
1	Coal (PF base)	Rs 0.42	Rs 0.21	
2	CCGT	Rs 0.27	Rs 0.36	
3	IGCC	Rs 0.0.65	Not Applicable	

8.4.4 It can be seen that while the cost levels of India and US are in close range in respect of Coal based units, there is a wide difference in respect of CCGT units. This could be attributed to higher establishment and human resource costs in the US.

8.4.5 No separate costs have been identified for other technologies like CFBC presumably since these are yet to mature as a utility power generation mode.

9.0 SMALLER Vs LARGER POWER STATIONS: AVAILABILITY AND ECONOMICS

9.1 General:

9.1.1 A brief exposition on the primary aspects of adopting smaller power stations in relation to larger units is discussed here. For the sake of comparison, a station consisting of 2 x 300 MW units is compared with an Ultra mega power station of 6 x 660 MW. Further, a base of 1000 MW has been considered here for comparing numerical figures.

9.2 Economics:

9.2.1 Incremental Coal Consumption: A 2 x 300 MW station is estimated to have an incremental net heat rate of 7% as compared to a 6 x 660 MW. This translates to an additional coal consumption of about 0.3 million tonnes per annum for 1000 MW.

9.2.2 Water: The incremental water consumption for a 2 x 300 MW station will be 15%, conservatively, translating to about 3.2 million m^3 of additional consumptive water per annum for 1000 MW.

9.2.3 Land: The estimated land requirement excluding ash dyke and colony for a 2 x300 MW station as compared to a 6 x 660 MW will be about 30%.

9.2.4 Capex: The Capex for a typical 2 x 300 MW is expected to be about 5 - 15% higher when compared to 6 x 660 MW in view of the economies of scale.

9.2.5 Opex: The O&M expense for a 6 x660 MW station will be appreciably lower as compared to a 2 x 300 MW station. As per CERC regulation for cost-plus projects, the difference between the configurations would be about 30%.

9.3 Availability and implication on grid stability:

9.3.1 Statistically, the availability of multiple stations of 2 x 300 MW configuration station will be higher than a large station of 6 x 660 MW for an equivalent power delivery. The contribution of a 6 x 660 MW unit on a regional grid as on date would be about 10%. Hence in case of outage of one unit, the regional grid has the potential to lose about 2% of the capacity, whereas the outage of one 300 MW will result in a loss of less than 1%. However, for several reasons, the consequence of a higher proportion of loss with larger units on the grid stability may not be severe in view of the following:

- The size of each regional grid has been growing much faster in recent years and hence the even in the short term, (say a 5 year horizon), the projected loss on account of outage of a 660 MW (or for that matter even an 800 MW) would be much smaller.
- Inter-regional transmission capacity has been increasing at a much faster rate recently. This is also expected to act as an additional cushion in case of failure of any major large unit in any part of the country.

9.4 Environmental aspects:

9.4.1 The emissions per unit net energy generated from stations with smaller units will be significantly higher as compared to those employing a larger unit, for multiple reasons, as discussed below.

9.4.2 Emission of SOx is expected to be in identical proportion to the increased heat rate (6 - 7 %).

9.4.3 However, NOx and SPM (as well as mercury) could be much higher. This is because in case of larger units of 660/ 800 MW, sophisticated combustion tuning (like employing Low NOx burner) is normally employed to bring down the NOx. Similarly, SPM also could be much lower since economies of scale permit installation of ESPs with far improved performance.

9.4.4 The difference in the cost of mitigating environmental pollution becomes stark when it comes to installation of FGD which is fairly nascent in India. While cost of FGD on larger units could increase the Capex and Opex marginally, in case of smaller units and station sizes, the incremental cost could be significant and can potentially increase the cost of electricity generated.

9.5 Externalities:

9.5.1 While economics in general favour large stations, a number of externalities are associated with such projects.

9.5.2 Land and water: Large stations require significant contiguous land for locating the power station and consumptive water on running basis. Many times, this may involve moving human settlements, clearing forests and sometimes even unsettling bio-diversity. In case of smaller stations, such externalities are limited.

9.5.3 Railway and transmission lines: Ultra mega power stations of 6 x660 or 5 x 800 MW configurations in the hinterland are planned to be located close to the coal mines and hence rail connectivity for fuel linkage does not become a hassle; however, even marginally smaller stations (say 3 x660 MW) require a significant quantity of coal (~30 000 TPD) which calls for rail connectivity. Further, evacuation of the order of magnitude of the generated power may also call for a fresh transmission system to connect with distant substations (400 kV or higher). For smaller stations, this would be of much smaller magnitudes.

9.6 Taking into account the various points discussed above, it can be seen that going for smaller power stations, while the availability may improve marginally, may not be attractive from an overall economic standpoint. Large power stations have the potential to increase social externalities; however, it is felt that so long as these are confined to localities close to coal mines or in coastal areas, the damage would be limited.

10.0 COAL BASED GENERATION: SOME AREAS OF EXPLORATION

10.1 Air Cooling:

10.1.1 The cumulative consumptive water requirement for thermal power generation in the country by the end of 13th plan is expected to be in the vicinity of 5000 Million m3, close to the total hold up capacity of some of the biggest dams in the country. This can have serious consequences on the perennial availability of water for power generation in case the inflows during monsoon seasons fall short.

10.1.2 Hence the air cooling option can be seriously explored for projects based in the hinterland in view of the depleting water resources in the country as well as the pollution caused by chemical wastes from treatment of large quantities of raw water.

10.1.3 Though a number of large size overseas units are operating with air-cooled condensing systems, as per the available information, no large stations are operating in India at present. There are two major reasons for this:

i). In view of the tropical climate, the basic size of the air cooled condenser in India itself is larger, ~ about 30% more in size.

ii). The size is also further increased in view of the much higher margins of surface area calculations for India in view of substantially high background dust pollution in Indian power stations.

iii). Air cooled systems, apart from higher Capex, have a significant energy penalty which can run counter to energy efficiency improvement programs.

10.1.4 Still, at a macro level, it is a question of priority and it is understood that the CEA is exploring this option through a committee.

10.2 Coal washing/ drying :

10.2.1 A number of niche coal washing/ drying processes are now available for coal/lignite. Drying is especially suited for lignite. The barrier could be cost which could be leveraged with the scale.

10.2.2 In view of significant ash content in Indian thermal coal, (average 40 %), the capacity of coal and ash handling systems is substantially higher as compared to typical overseas plants.

10.2.3 Storage and disposal of ash generated from thermal plants entails significant Capex and Opex, besides creating environmental hazards.

10.2.4 At present, the washing method predominantly used in India for coal is wet washing.

10.2.5 As per the ruling MOEF guidelines, all power plants located 1000 km or beyond have to use washed coal; it is understood that this threshold is being revised to 500 km.

10.2.6 Wet washing is found to be cost economic only marginally for the following reasons:

i) The heat gained by the reduced ash content (on unit mass basis) is nullified by the increased moisture content.

ii). The yield (net mass of washed coal per unit input coal) is found to be inversely proportional to the ash content in the washed coal, as can be seen from the following typical washability curve:

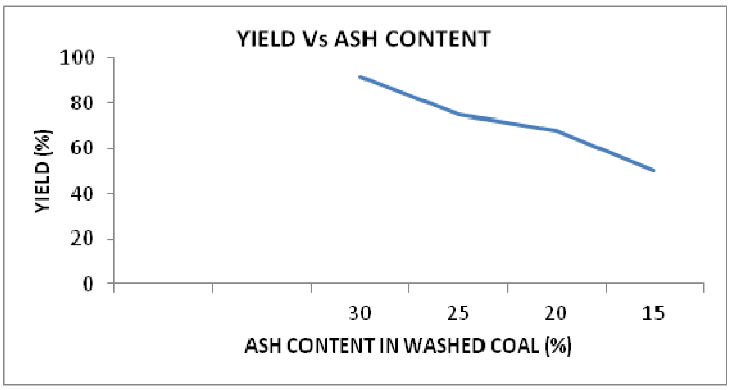

CHART 7.5: WASHABILITY CHARACTERISTICS OF COAL

10.2.7 Wet washing of coal requires abundant quantity of water also.

10.2.8 Recently, dry washing of coal has picked up momentum.

10.2.9 One of the technologies which has been pilot tried in India is developed by Virginia Tech (US) using air. Pilot trials have been done in Aryan Coal and Bhushan steel. No data regarding the economics is available.

10.2.10 However, keeping in view that at present, less than 25% of the thermal coal is getting washed, and the environmental cost of using unwashed coal is escalating in view of the increasing footprints of thermal power units in the country, it could be worth looking for economies of scale for dry methods of coal washing.

10.2.11 In case of lignite, the predominant attribute for beneficiation is drying in view of the substantial moisture content present, especially in the case of lignite at Neyveli mines.

10.2.12 In lignite drying also, there are several methods; most of them use either waste heat or flue gas re-circulated from the boiler.

10.2.13 In lignite drying also, a number of companies have been exploring cost economical options.

10.2.14 RWE, a German utility, has patented a technology which uses flue gas re-circulated from boiler for drying of lignite for their Neurath power station.

10.2.15 One of the large US power plants[119] has improved the efficiency by using a fluidized bed lignite drying system which reduced the moisture content from 39% to 29% and significantly improved boiler efficiency.

10.2.16 In general, the attractiveness of coal washing/ lignite drying comes from economies of scale and keeping in mind the escalating cost of fuel during the past years, the economic gains from increased efficiency with relatively dry lignite should offset the Capex and Opex associated with the drying process.

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ANNEXE 2

FUTURE OF NATURAL GAS IN INDIA FOR POWER SECTOR

Annexe 2

FUTURE OF NATURAL GAS IN INDIA FOR POWER SECTOR

By

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Executive Summary

This study reviews the Natural Gas sector to understand the future scenario of supply from domestic sources of Natural Gas, (both conventional and unconventional), and imports, and the impact on the demand of the proposed increase in the price of domestic gas. From this, the scope of increasing gas based power generation capacity is discussed.

An overview of the consumption, supply, demand and production in recent years is provided. It is noted that the demand figures provided do not factor in the impact of price, even though the power and fertiliser sectors are known to be price-sensitive sectors. Projections for future production of NG are also provided.

The future potential for production of NG is examined by compiling data from various studies and reports. The status of Conventional Resources of NG is examined, along with an indication of growth plans and hurdles faced in conducting Exploration and Production activities.

The potential from Unconventional Resources is examined, covering CBM, Shale gas, UCG, Petcoke gasification, and Gas Hydrates. The difficulties are also noted.

On compiling the above data, it is found that the potential from Unconventional resources is larger than from Conventional ones. It is recommended that more effort should be directed towards Unconventional resources. It is noted that India does not seem to follow global standards for reporting of NG resources.

The efforts made for developing gas fields overseas are noted.

The import of NG is then examined. The LNG sector is discussed, including the investments required along the entire chain, and the import facilities in India. The cost structure of LNG is examined along with the scope for its use by the Fertiliser and Power sectors. The global LNG scenario is examined, which shows that future exports from USA will have a moderating influence on LNG pricing in Asia.

The pipeline network in India is discussed, and the issues that surround it.

The scope for bringing NG by overland pipeline from nearby gas rich countries is discussed.

A brief idea of international gas trends is provided.

The requirement of NG for the power sector is discussed.

The proposal to increase domestic NG prices from April 2014 is discussed, along with its implications for Fertiliser and Power sectors. It is noted that these sectors may not be able to afford such expensive gas, and that investments in new capacities may not occur. This will reduce the total future requirements of NG in the country, which will affect the growth of the LNG and pipeline infrastructure. The issues regarding use of gas based power for meeting peak-load requirements are discussed.

It is concluded that the scope for generating additional power by expanding gas based capacity is presently limited by both supply and pricing of NG. Alternate fuels should be considered.

Introduction

India has been using Natural Gas for over three decades. Its advantages are well understood, which has raised the demand for it. However, availability to meet all requirements is a major issue. An overview is provided here for the likely future demand and its likely availability from various sources in coming years.

Natural Gas is predominantly Methane[CH_4]. When the Methane content is over 98%, it is called Lean Gas. If it contains about 3 - 5 % of higher hydrocarbons, such as Ethane [C_2H_6], Propane [C_3H_8] and Butane [C_4H_{10}], then it is called Rich Gas. The Propane and Butane are extracted, and sold as LPG for burning as a fuel. The higher hydrocarbons can also be extracted for conversion into petrochemicals such as LDPE, and PP. After extraction, the balance gas which is almost all Methane can be used as NG.

The chemical industry utilises the chemical properties of Natural Gas ("NG") for producing important products such as:

- bulk fertilisers: Urea, DAP and Nitro-Phosphates/ NPK complex fertilisers
- inorganic chemicals: ammonia, nitric acid, ammonium nitrate (used extensively in mining globally).
- organic chemicals: methanol, acetic acid, acrylonitrile, acetonitrile, etc (used for pharmaceuticals, synthetic fibres/textiles, other industries),
- polymers: polyethylene, polypropylene, polystyrene, etc.

NG is the preferred raw material for the manufacture of Nitrogenous fertilisers: In India, 65 % of this capacity is gas-based; in the case of Urea, which is the most important fertiliser within this group, 81% of capacity is gas based, and steps are under way for conversion of the remaining units to NG[1].

NG also has high energy content. It is used in power stations to generate electrical power, as CNG (Compressed NG), to drive a bus or car, as Piped NG to cook food, and in Boilers to generate steam for commercial usage. In these applications, NG is a substitute for coal, diesel, LPG and fuel oil respectively. Its use depends on its pricing competitiveness. In India, about 18,400 MW of installed power generating capacity was gas based as of Mar 2012, accounting for 9% of the total.[2] In addition, about 13,000 MW of gas-based capacity was under installation as of end 2011.

When NG is used by the chemical industry, the carbon content of NG is mostly captured into the end products. However, when NG is burnt for fuel for power, transportation, cooking and other applications, then the carbon is released into the atmosphere as Carbon Dioxide.Thus, chemical usage of NG is more environmentally friendly than fuel usage.

Units of Measurement, and special terms used

A peculiarity of this sector is the variety nits of measurement used, as well as the use of some special terms. As these various units and terms will be used in the report, a summary is given in Annex 1to make this report easier to understand.

Consumption of Natural Gas in India [3]

The growth in the consumption of NG has been constrained by availability. There was a spurt in consumption for two years, in 2009-10 and 2010-11, on the strength of new domestic supplies, namely KG D6 fields. However, the decline in production from these fields has throttled consumption.

Table 1 Natural Gas Consumption 2004-05 to 2012-13 in mmscmd, and Total BCM

Consumption mmscmd)	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
PowerGeneration	35.04	35.82	37.19	38.37	42.07	64.89	77.78	62.78	53.88
Fertilizers	24.49	24.91	28.18	32.91	36.59	43.14	44.22	38.91	45.54
Refineries/ industries	12.09	14.36	14.18	15.69	16.58	14.13	14.52	13.08	12.24
CGD	2.73	4.5	5.01	9.62	10.92	12.1	14.78	15.57	16.98
Petro-chemicals	3.91	4.13	5	5.42	5.21	5.23	5.1	5.52	5.77
CaptiveUse/ LPGshrinkage	13.55	13.83	13.79	4.94	5.16	14.88	12.45	10.15	8.63
Others	3.01	5.66	7.11	6.78	7.41	8.35	9.19	19.08	14.39
Total	94.82	103.21	110.46	113.73	123.94	162.72	178.04	165.09	157.43
Total in BCM	*34.6*	*37.7*	*40.3*	*41.5*	*45.2*	*59.4*	*65*	*60.3*	*57.5*

Between 2004-05 and 2010-11, the CAGR for overall consumption of natural gas was 11.07%. In this period, the CAGR for the power sector was 14.2%, for fertilizer sector 10.4%, and CGD 32.5%. Power and fertiliser sectors account for about 65% of the total NG consumption. After domestic production started declining, only CGD maintained growth, since it can afford to use LNG, unlike Power, Fertilisers and Petrochemicals, whose end product prices are either regulated or face import competition. CGD has reached a sizable level of 17 mmscmd by 2012-13, or 10% of total consumption.

The chart clearly shows that the Power sector has always been the largest consumer of NG. It had its best year in 2010-11, but declined thereafter. The Fertiliser sector however increased its consumption in 2012-13 since it has been given the highest priority in allocation of NG. It also consumed some LNG in order to maintain production levels.

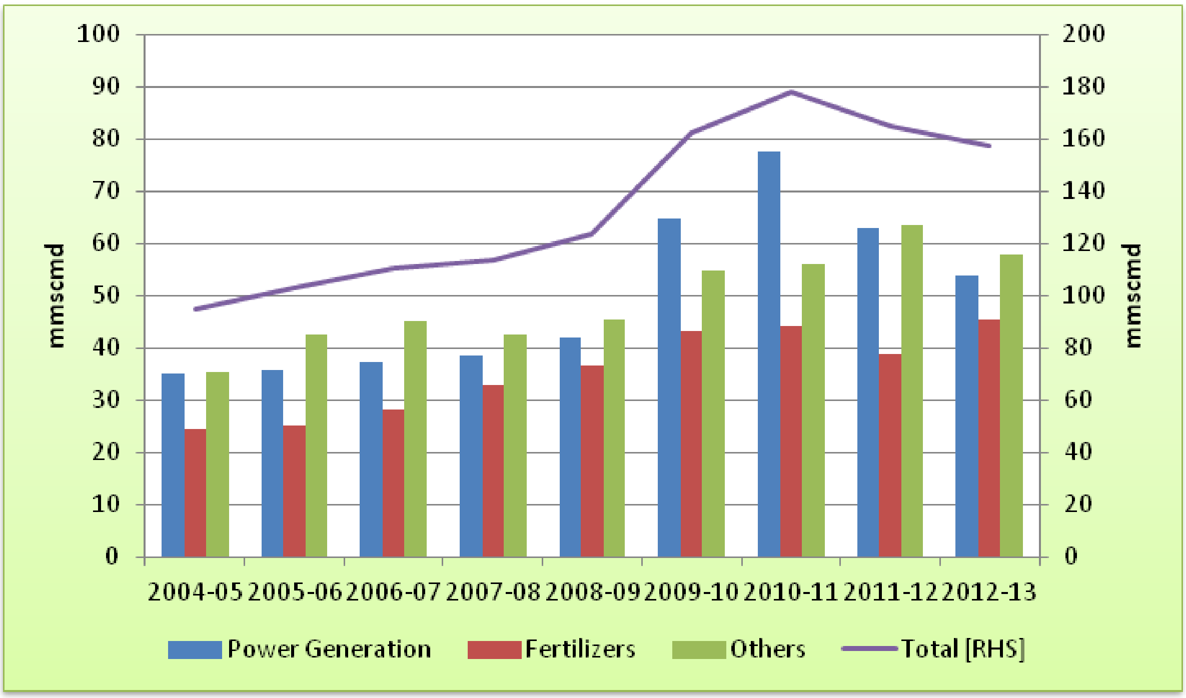


Chart 1 Consumption Trend of NG for selected sectors

Supply of Natural Gas in India [4]

The production of domestic gas has been supplemented by the import of LNG.
The decline in domestic production was partly compensated by increase in imports of LNG.

Table 2 Natural Gas Supply 2004-05 to 2012-13 in mmscmd

Supply (mmscmd)	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Domestic Supply	84.32	85	85.94	83.78	90.38	127.41	140.9	125.77	111.44
Imported LNG	10.5	18.21	24.52	29.95	33.56	35.31	37.14	39.32	46
Total	94.82	103.21	110.46	113.73	123.94	162.72	178.04	165.09	157.44

The chart clearly shows how steep the increase in production was after 2008-09 and the sharp decline from 2011-12.

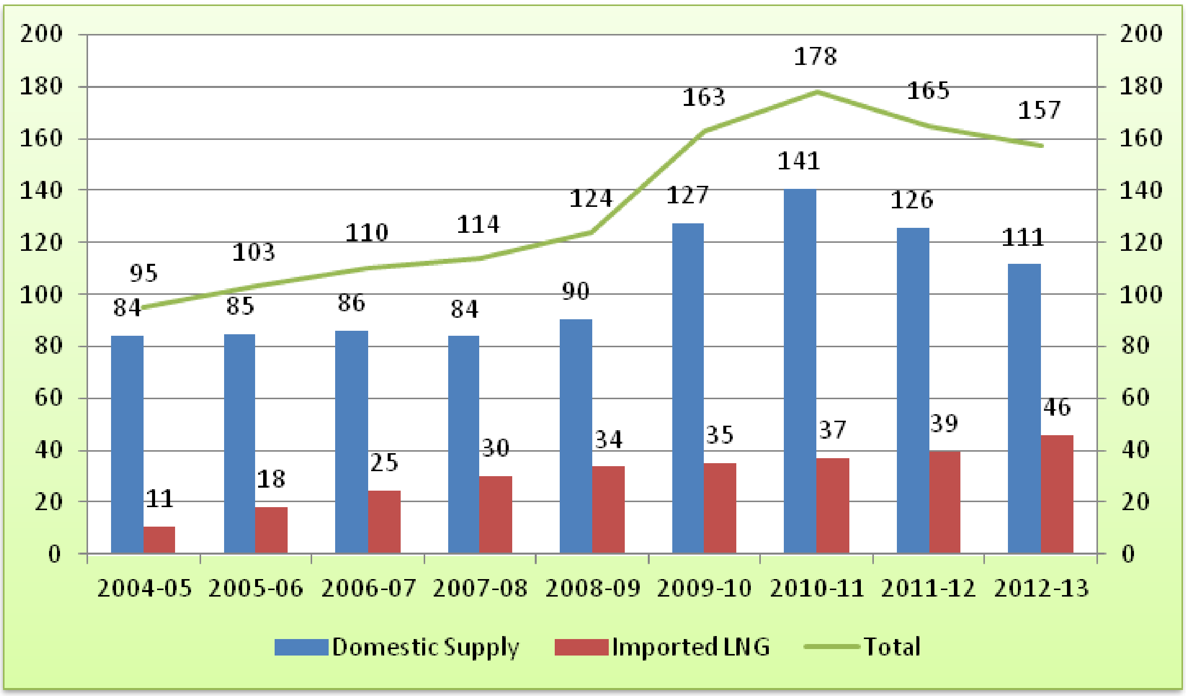


Chart 2 Supply trend for Natural Gas 2004-05 to 2012-13

Imports of LNG started in 2004. Its share steadily increased in the domestic market till 2008-09, then declined as the domestic production increased, but then has again started increasing from 2011-12. It reached its maximum of nearly 30% in 2012-13.

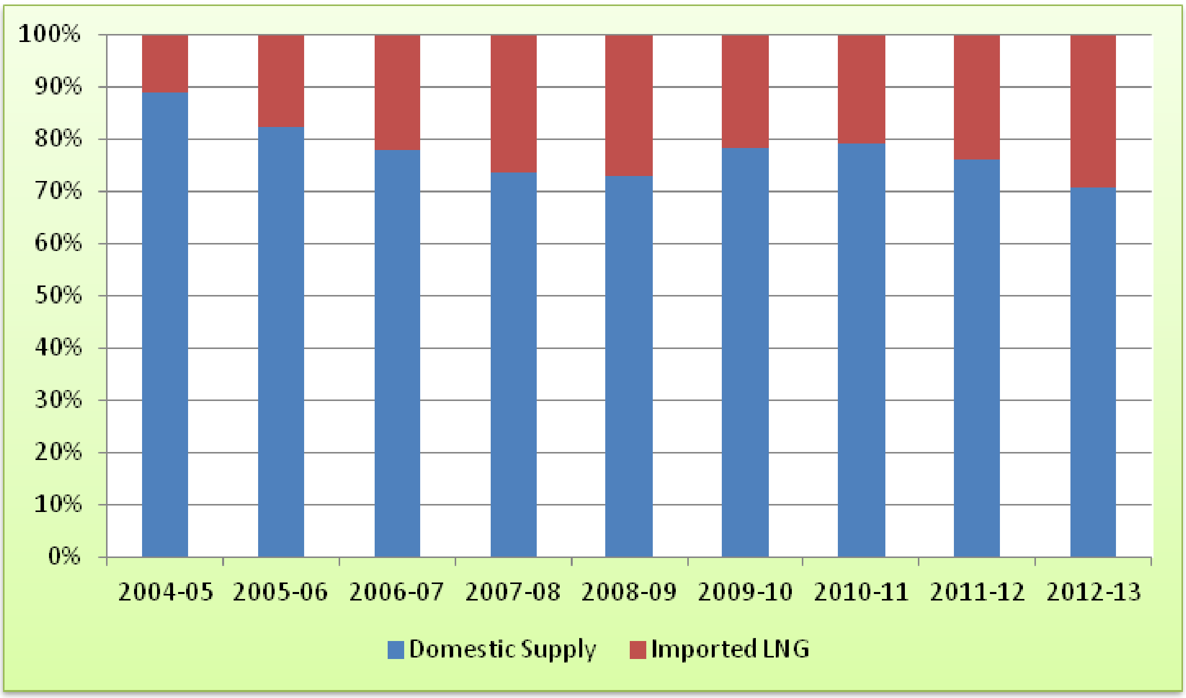


Chart 3 Share of LNG in total supply of NG 2004-05 to 2012-13

Demand for Natural Gas in India

The Planning Commission had coordinated the preparation of the Report of the Working Group on Petroleum and Natural Gas sector for the 12th Five Year Plan (2012-2017). Considering the importance of this sector, and the need to ensure a long term view, the demand projections were extended beyond the immediate 12th Plan but to the 13th Plan also. The data is provided in the two tables below.

Table 3 NG Demand Projection for 12th Five Year Plan Apr 2012 to Mar 2017

Sector *Figures in mmscmd*	*2011-12*	2012-13	2013-14	2014-15	2015-16	2016-17	CAGR (%)
Power	*91*	135	153	171	189	207	17.9
Fertilizer	*43*	62	110	113	113	113	21.3
City Gas	*13*	15	19	24	39	46	28.8
Industrial	*16*	20	20	22	25	27	11.0
Petrochemicals/ Refineries/ Internal Consumption	*25*	54	61	67	72	72	23.6
Sponge Iron/Steel	*6*	7	8	8	8	8	5.9
Total Demand	*194*	293	371	405	446	473	19.5

The growth in demand is projected at a high level of 19.5% in 12th Plan, but much lower at 5% in the 13th Plan. Thus demand in 2016-17 is projected to be 2.4 times that in 2011-12.The demand growth for NG from the Power sector is projected at almost 18% in 12th Plan and at 8% in the 13th Plan. In case of the Fertiliser sector, strong growth upto 2014-15 is followed by nil growth thereafter; this implies that import dependence on urea will continually increase after 2015 or so. CGD is projected to have the strongest growth in the 12th Plan period.

Table 4NG Demand Projection for 13th Five Year Plan Apr 2016 - Mar 2022

Sector *Figures in mmscmd*	*2016-17*	2017-18	2018-19	2019-20	2020-21	2021-22	CAGR(%)
Power	*207*	225	243	261	289	307	8.2
Fertilizer	*113*	113	113	113	113	113	0.0
City Gas	*46*	47	50	53	55	57	4.4
Industrial	*27*	28	32	35	37	37	6.5
Petrochemicals/ Refineries/ Internal Consumption	*72*	72	76	80	82	82	2.6
Sponge Iron/ Steel	*8*	9	9	10	10	10	4.6
Total Demand	*473*	494	523	552	586	606	5.1

An important feature of these projections is that they do not relate demand to the price of NG. This is a surprising lacuna, since this is a well known relationship, andis crucial for several of the major users of NG. It is a major cost component in their total cost of production, namely power, fertilisers, and industries have to sell their products in competition with imports.

Table 5 Cost impact of NG on various end uses

	Nature of usage	Cost contribution	Market situation
Fertilisers based on Ammonia	Used as feedstock and fuel for manufacture of ammonia, from which urea and NP fertilisers are made. NG is the only raw material required for Urea	Very high	Urea is sold at administered price, while other fertilisers are sold at prices partly related to the market. However, prices of non urea fertilisers have to be moderated as they compete with cheap urea for the farmer's limited budget
Power	Sole fuel	Very high	Gas based power has to compete with coal based power, in order to get load despatch schedule under merit order rule
Petrochemicals	Used as feedstock and fuel for manufacture of Ethylene and Propylene. NG is the only raw material	Very high	Competes with imports from the middle east where gas prices are $ 1 – 2 /mmbtu
Sponge iron / steel	Used as important feedstock, and fuel	Moderately high	Competes with imports from low cost areas
City gas as cooking fuel	Substitute for LPG	Small in relation to total household budget	LPG sold at subsidised rates to many customers. Also imported, so affects forex situation
City gas as transportation fuel	Substitute for petrol and diesel	Small in relation to total household budget; moderate/high in transportation budget	Petrol and diesel sold at subsidised rates. Also subject to high taxes, which do not apply to City gas
City gas for industrial and commercial use	Used as fuel	Small in relation to total budget	Convenience is main factor

In fact, the MoPNG is reported to have arrived at the following price demand relationship in 2005 for NG demand by the power sector:[5]

Table 6 NG Price Demand relationship for Power sector 2005

Delivered Price of NG	NG Demand
US$/mmbtu	*mmscmd*
3.0	178.0
3.5	140.0
4.0	100.0

The absence of the price-demand elasticity factor in these demand projections vitiates their validity.

Production in recent years

The domestic production of NG for past few years is given below. It includes conventional on-shore and off-shore gas, as well as CBM.

Table 7- Domestic Production of Natural Gas 2007-08 to 2012-13 in BCM

		Pvt / JV	ONGC	OIL	Total
		BCM	BCM	BCM	BCM
2007-08	Actual	7.73	22.33	2.34	32.40
2008-09	Actual	8.09	22.49	2.27	32.85
2009-10	Actual	21.99	23.11	2.42	47.51
2010-11	Actual	26.77	23.10	2.35	52.22
2011-12	Actual	21.61	23.32	2.63	47.56
2012-13	Actual	14.49	23.55	2.64	40.68

Source:

These figures are also given below in terms of mmscmd:

Table 8-Domestic Production of Natural Gas 2007-08 to 2012-13 in mmscmd

Source		Pvt / JV	ONGC	OIL	Total
		mmscmd	mmscmd	mmscmd	mmscmd
2007-08	Actual	21.17	61.19	6.42	88.78
2008-09	Actual	22.16	61.61	6.22	89.99
2009-10	Actual	60.23	63.31	6.62	130.16
2010-11	Actual	73.35	63.27	6.44	143.07
2011-12	Actual	59.20	63.88	7.21	130.30
2012-13	Actual	39.70	64.52	7.23	111.45

The details for the last completed year 2012-13are as follows:

Table 9 Details of Production of NG for 2012-13

State/ Region	ONGC	OIL	Pvt./JV Companies	Total	Share
	(BCM)	(BCM)	(BCM)	(BCM)	%
Offshore	18.102	0	13.700	31.802	78.2%
Andhra Pradesh	1.248	0	0	1.248	3.1%
Arunachal Pradesh	0	0.019	0.022	0.041	0.1%
Assam	0.485	2.425	0	2.910	7.2%
Gujarat	1.846	0	0.186	2.032	5.0%
Rajasthan	0.014	0.195	0.476	0.685	1.7%
Tamilnadu	1.206	0	0	1.206	3.0%
Tripura	0.647	0	0	0.647	1.6%
West Bengal	0	0	0.107	0.107	0.3%

State/ Region	ONGC	OIL	Pvt./JV Companies	Total	Share
Total BCM	23.548	2.639	14.491	40.678	100.0%
Total in mmscmd	64.5	7.2	39.7	111.4	
Share %	57.9%	6.5%	35.6%	100.0%	

A view of the major contributors to production of NG in 2011-12 shows that most of the production is from Nomination and Pre-NELP fields[6].

Table 10 Producing Fields Ranked by Percentage Share

Companies	Region	Mil cu metres	% share	Field type
ONGC	Mumbai Offshore	17,540	37%	Nomination
RIL/BPEAL/Niko	KG Offshore	15,611	33%	NELP 1
BG-RIL-ONGC	Mumbai Offshore	4,300	9%	Pre-NELP
OIL	Assam-Arakan	2,410	5%	Nomination
ONGC	Cambay	1,939	4%	Nomination
ONGC	KG (Onland + Offshore)	1,389	3%	Nomination
ONGC	Cauvery Onland	1,285	3%	Nomination
ONGC	Assam-Arakan	1,148	2%	Nomination
Others	All	1,936	4%	Mixed
Total	All	47,558	100%	

These have been in production for over two decades, and are showing declines. The only other large contributor is KG D6, which has shown a large decline even before reaching its expected peak. This indicates that the future depends a lot on the ability to:
- enhance recovery from existing fields,
- bring into production fields where NG has been discovered, but have not yet been developed, and
- find new fields through exploration efforts.

It should be noted that ONGC has taken major steps in all these three areas. It has made large investment of about Rs 31,000 crores made in projects to enhance the recovery from existing fields. Out of 24 such projects, 16 are completed, and 8 are ongoing. The total envisaged gain is 172 mil tonnes in Oil and Oil equivalent Gas (O + OEG); of this, about 80 mil tonnes has been achieved till March 2013. Thus, another 92 mil tonnes is expected in the coming years.

These projects have enabled ONGC to maintain production levels from Mumbai High. Earlier indications had been that the supply of NG from Mumbai High to the Uran/ Maharashtra region would drop to nil by 2005 or so. However, these projects have enabled it to maintain supplies at a level of about 10 mmscmd even till now, with hopes of continuing for a few more years. This has enabled continuity of operations for fertiliser, power, steel and petrochemical units that depend on Mumbai High gas.

ONGC has now identified 10 major projects for (re)development:

1. Mumbai High North Redevelopment Phase-III
2. Mumbai High South Redevelopment Phase-III
3. Neelam- Heera redevelopment
4. South Bassein – Additional Development
5. Daman-C Series

6. GK-28/42
7. Manik
8. KG-98/2
9. KG-98/2-UD
10. Gamij, Ahmedabad

These are expected to provide additional 300-400 mmtoe of oil and NG. [7]

Projections for production in future

The original projections for gas production during the Twelfth Five Year Plan period for April 2012 - March 2017 were as follows:

Table 11 Original Projections for NG Production during Twelfth Five Year Plan Apr 2012 - Mar 2017

Producing Source	Private / JV	ONGC	OIL	Total
	BCM	BCM	BCM	BCM
2012-13	23.71	25.27	3.30	52.28
2013-14	32.38	25.47	3.80	61.65
2014-15	39.40	26.67	4.00	70.07
2015-16	40.43	28.22	4.27	72.92
2016-17	41.46	38.68	4.45	84.59

However, the projections have been subsequently reduced in May 2013, with a further reduction in August 2013, due to the continued decline in production in output from the KG D6 block. This update separated the data according to whether the field was Nominated or Pre-NELP or NELP or CBM type.

Table 12 Revised Production Estimate for 12th Plan (Aug 2013)

Figures in mmscmd

Block type	ONGC	OIL	PSC	PSC	PSC	All	Nominated	PSC
Category	Nominated	Nominated	Pre NELP	NELP	CBM	**Total**	Sub total	Sub total
2012-13	64.5	7.2	39.7		0	**111.4**	71.7	39.7
2013-14	64.220	7.500	13.045	19.770	0.800	**105.335**	71.720	33.615
2014-15	73.070	10.960	12.021	19.566	2.989	**118.606**	84.030	34.576
2015-16	77.320	11.230	12.228	20.270	5.772	**126.820**	88.550	38.270
2016-17	105.970	11.510	11.719	25.023	8.472	**162.694**	117.480	45.214

Thus, output growth is now expected to be much slower than originally projected for the 12th Five Year Plan.

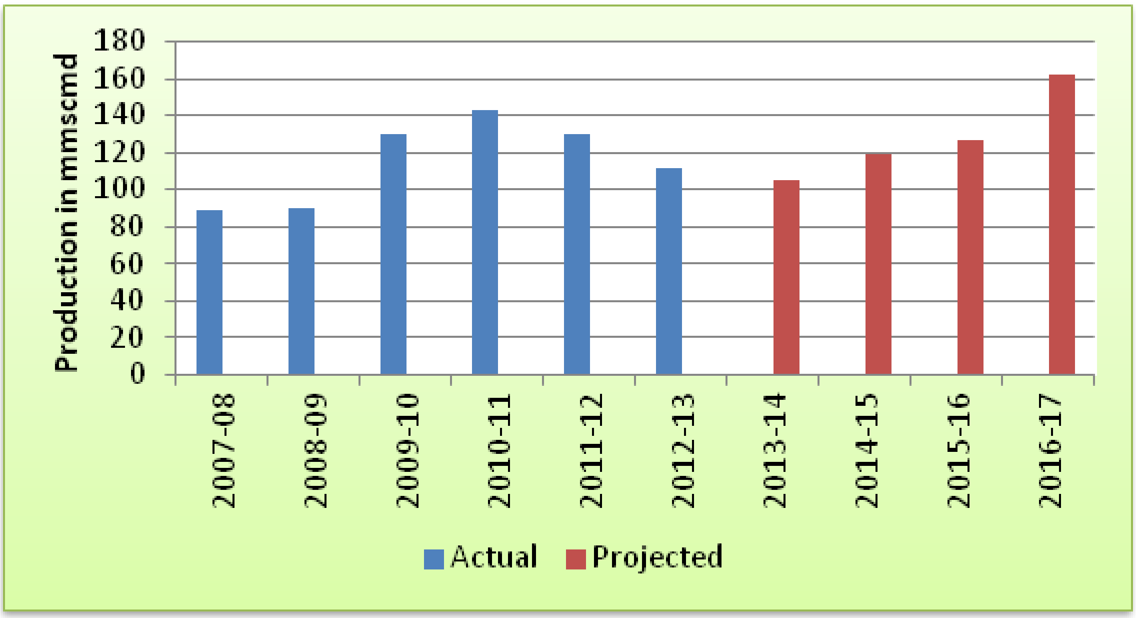


Chart 4Natural Gas Production – Past Actual and Future Projected (as of August 2013)

Uncertainties in Production volumes

The projections for production of Natural Gas during theTwelfth Plan period April 2012 to March 2017 have undergone significant changes in the past two years. This is graphically represented below:

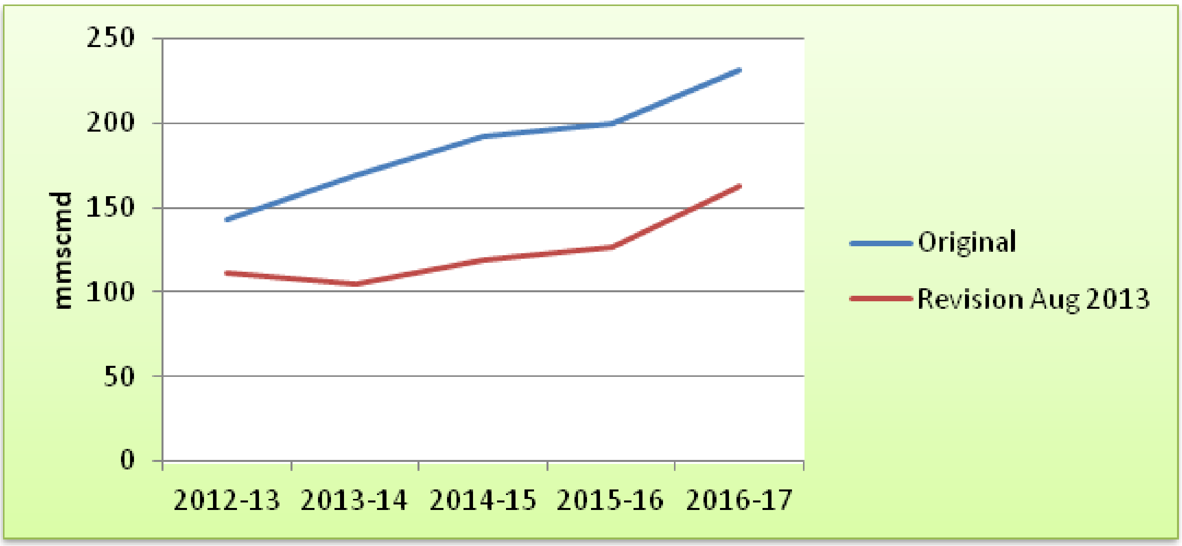


Chart 5Change in Production Projections for Twelfth Plan period April 2012 to March 2017

A major reason is the large deviation between projection and actual production for KG D6. The learning from this experience is that the oil and gas industry is not one where the future can be predicted with great certainty. It is important to understand that production of Natural Gas output is liable to show a large variation from what is originally projected.

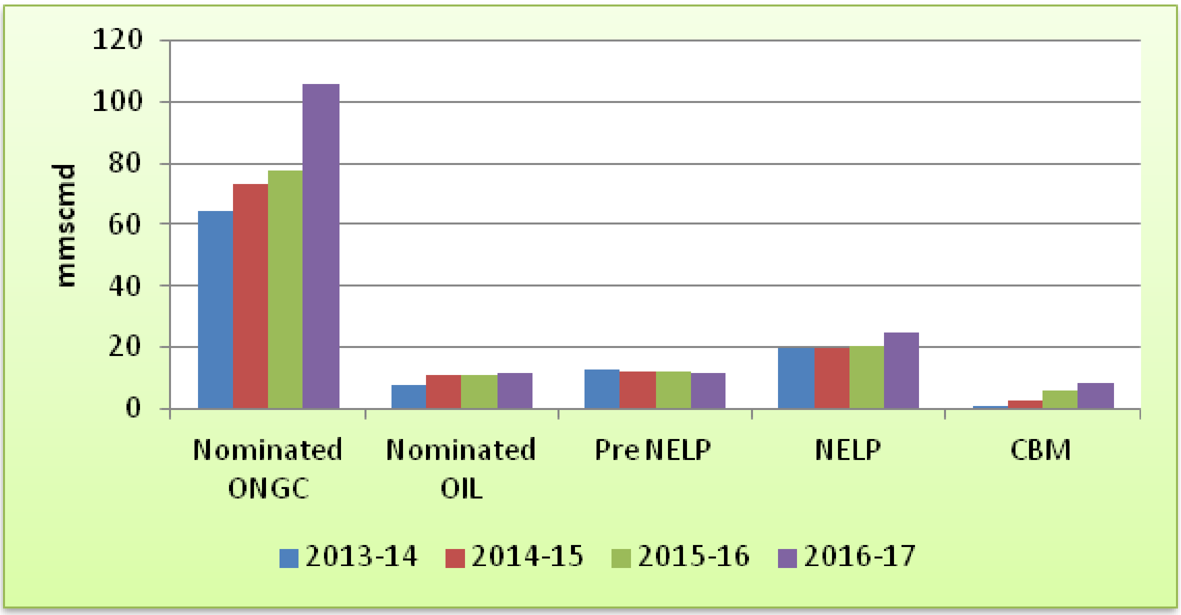
In fact, many will say that all projections have to be treated with caution. Investment decisions by the NG consuming industry must build in contingency plans to avoid suspension of operations due to failure of NG supplies. A credible / realistic contingency plan will ensure financial stability when faced with adverse gas supply situations.

Gas customers would like to validate future gas production data by examining reserves data and production plans from each of the organisations, for each field that contributes to the total output.
Unfortunately, such a culture of open sharing of data has not yet developed in India. It requires a concerted effort from all user sectors to convince the concerned agencies to share their data.

Unfortunately, user sectors are forced to invest/ operate on the basis of un-verified data. Financial agencies that provide loans for funding the downstream investments should join this effort, as they would certainly need to de-risk their lending.

<u>Analysis of Twelfth Plan projections</u>
Converting the data given in Table 7 into a chart enables us to analyse the data further.

Table 13 Production Projections by Field Category



It is seen that the there is regular increase in output of ONGC's Nominated blocks, and a major change in the terminal year 2016-17. All Nominated blocks were given to ONGC and OIL in the 1960's when the Exploration activity was in its infancy, and being promoted by the Government of India. All these blocks are quite old, of the order of three decades. They are all said to be in their decline phase. The output from Nominated blocks of both ONGC and OILshows significant increase in these 4 years:
- ONGC from 64 to 106 mmscmd, i.e. growth of 42 mmscmd which is 65% more than 2013-14.
- OIL from 7.5 to 11.5 mmscmd, i.e. growth of 4 mmscmd which is 54% more than 2013-14.

In 2013-14, will provide 12- 13 mmscmd of NG, after factoring in the natural decline in existing fields. Further, G1 and GS 15 fields in the KG basin are under ramp up of production.

In 2014-15, production fromONGC operated fields is now forecast at around 25.10 BCM, that is about 68 mmscmd. Further, the PMT JV is now forecast at about 9.5 mmscmd. Major increase in production is expected from the KG basin, in stages over the next 3 to 5 years. [8]

In coming years, the output will increase due to ONGC presently implementing 13 projects to monetize 37 fields, at an investment of over Rs 31,000 crores. The expected production is 64 BCM of NG, and 40 MMT of Oil. Most of these fields are in the Western offshore. These include production from marginal fields, primarily the D1, Cluster 7, C series, B series, WO series,WO-16, B193, B22, and SB14 in Western offshore. These include the Daman offshore area, (C-23, C-26, B-12 and C-24 fields) which are to be brought on stream by 2014-15 (i.e. 4 years earlier than planned), as it has substantial gas potential. [9] Of the 13 projects, one was completed in FY13, 7 will be completed in FY14 & balance 5 in FY15. [10]

In order to get an idea of the daily volume that may be available from the proposed output of 64 BCM of NG, we may apply the assumptions that, if their life is 10 years onaverage, then the output would be about 17 mmscmd. A longer life will reduce the daily output. The 64 BCM figure must be a composite of many fields, each with different start and ending dates, and a plateau period.

On the KG basin, ONGC is progressing on several discoveries:
- Integrated development of G-1 and GS-15 blocks: both recently came on stream
- The block KG-DWN-98/2 is estimated to have an Initial in-place gas of 4.85 TCF, that is >130 BCM. The envisaged peak production is 22 mmscmd. The field is to be developed by 2016-17. All 4 wells drilled (2 each in the South and North Discovery Areas), have been hydrocarbon bearing. Eight additional wells are planned by Dec.2013.
- BlockG-4 is planned to be developed along with the discoveries in the Northern Discovery Area of KG-DWN-98/2 during 2017.
- TheblockG-4-6 is under appraisal; it has considerable potential, and could provide cumulative Gas production of about 43 BCM. It is proposed to undertake integrated development of VA & S1 by 2015.

In the Mahanadi Basin, 7 appraisal wells planned before establishing commerciality.

ONGC is currently undertaking a total of 41 projects with total approved cost of Rs 80,181Crore, of which 80% is on Offshore. These projects are estimated to produce89 BCM of Natural Gas, and 106 MMT of Crude oil.

ONGC is presently operating in 27 deep-water blocks in India. It has drilled 104 deep-water wells as on March 2013, including an Ultra deep-water well of 3,008 m. It has made 35 deep water discoveries, of which 28 have Gas, and remaining have both Oil & Gas.
(KG-7; CY-4; CY-PR-2; MN-NEC-3; AN-9; KK-2)

Disclosure Norms

The above projections also need to be validated, by examining reserves data and production plans from each of the organisations, for each field that contributes to the total output. Unfortunately, such a culture of open sharing of data has not yet developed in India. It will require concerted effort from all the user sectors to convince the concerned agencies to share their data, failing which the user sectors will be forced to invest on the basis of un-verified data. User sectors should take the support of the financial agencies that provide loans for funding the downstream investments, as they would certainly need to de-risk their lending.

It will be helpful to examine the disclosure norms that prevail in other countries having democratic processes, and strong stock exchanges. Countries such as Canada, USA, Australia, may be studied for the transparency requirements placed on the E&P sector.

Future Prospects

Natural Gas, crude oil, coal and shale are all related in that their origin is organic matter that has been transformed after having been buried underground for millions of years. NG is found in nature in a variety of geological locations. It is referred by different names, depending on the source, as follows:

1) Conventional non-associated gas: where the gas is trapped in a reservoir, and can be extracted by conventional drilling methods
2) Conventional associated gas: where the gas is trapped along with crude oil in a reservoir, and can be extracted by conventional drilling methods,
3) Coal Bed Methane: methane is always found along with coal. It gets adsorbed on coal, with the binding being loose if the coal seams are shallow and becoming tighter as depth increases.
4) Shales are clays with a high concentration of hydrocarbons, which may be in the form of oil or gas depending on various geological factors.

The figure below provides a pictorial view of these different forms.

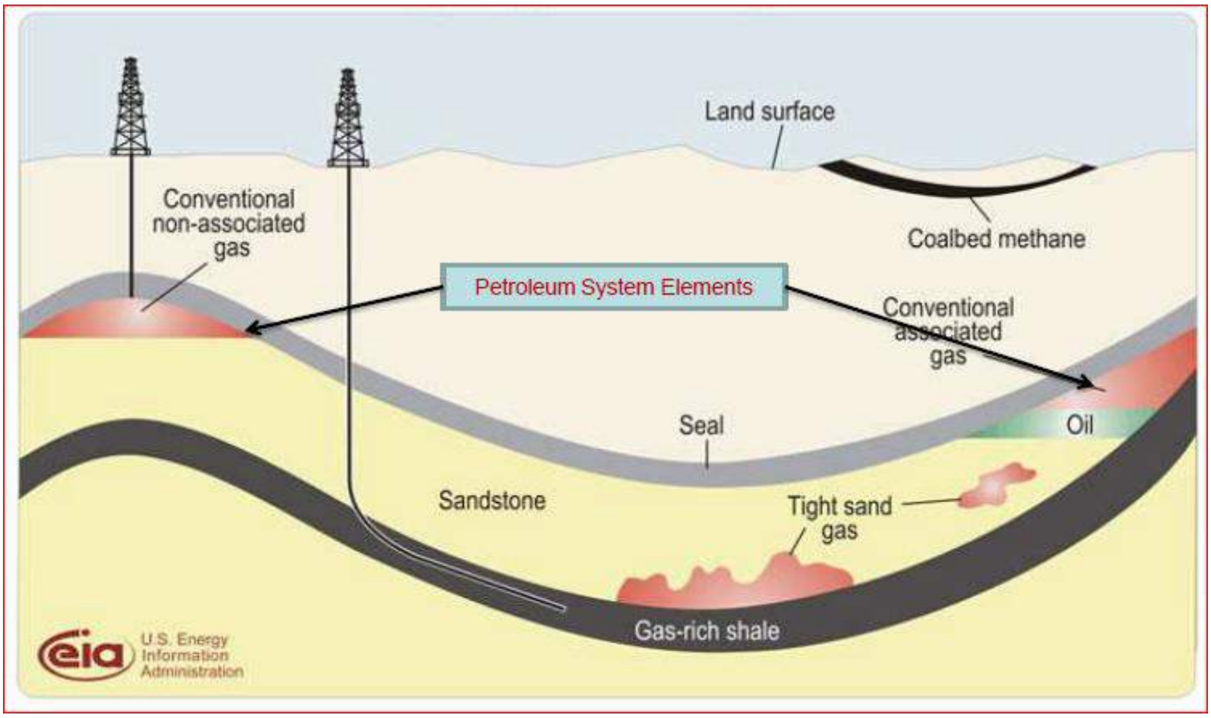


Figure 1 Schematic Geology of Natural Gas Resources

A number of studies are available regarding the gas reserves in India. The following summarisesthe data from them.

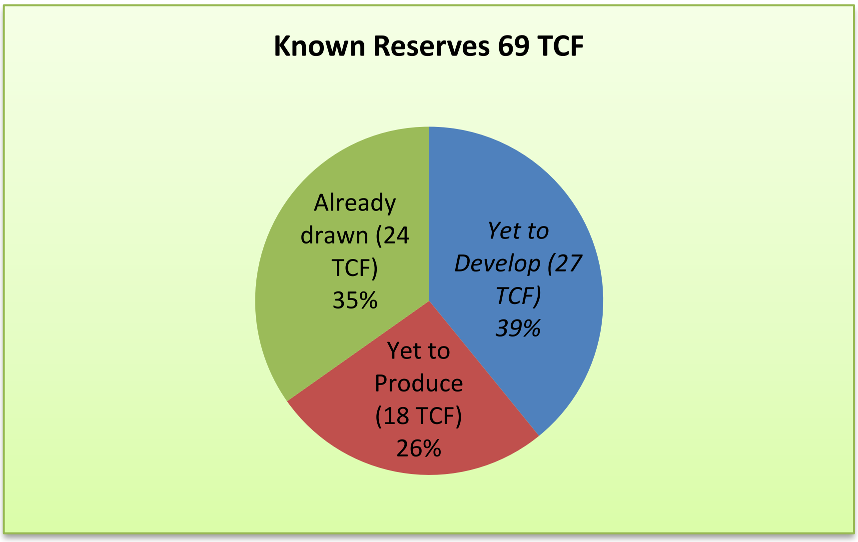
IHS CERA Study

In early 2013, the well known international consulting firm, IHS submitted a report[11] prepared by their CERA division, previously known as Cambridge Energy Research Association, to the Ministry of Petroleum and Natural Gas. Their study covered Conventional resources, and unconventional resources. The highlights of their presentation are given below:

Conventional Resources

1) Known Gas reserves:
    a. Between 1950 and 2012, the total recoverable gas reserves identified within the proved and probable categories amount to 69 TCF.
    b. Almost two-thirds of these, 42 TCF, are in production; little more than half of this gas has already been drawn / consumed, and 18 TCF are yet to be drawn.
    c. Another 27 TCF of discoveries are yet to be developed.
    d. Thus, available reserves are "Yet to Produce" 18, plus "Yet to Develop" 27, total 45 TCF.

Table14 Known Gas Reserves



2) "Yet to Find" Reserves: For conventional gas resources, the study examined 12 basins of India (out of total 26) with known reserves and potential:

Indus	Barmer	Cambay	Kutch	Bombay	Krishna-Godavari
Cauvery	Mahanadi	Bengal	Assam	Andaman	Tripura-Cachar

A special technique, called the Creaming Study, estimated that, in these basins, the reserves "Yet to Find"are about 64 TCF.

3) The study also indicates the location of the reserves. Combining the "Yet to Develop" and "Yet to Find"data, the following picture emerges for the total potential gas that could be available in India:

Table 15 Total Conventional Gas Reserves as per IHS

Type of Reserve	Yet to Develop TCF	Yet to Find TCF	Total Potential TCF
Offshore Ultra Deep:	10	17	27
Offshore Deep	4	22	26
Offshore Shallow	11	12	23
Onshore	2	13	15
Total	27	64	91

4) In case the entire quantity of 91 TCF gas can be extracted, then it would amount to 2,577 BCM. Our rate of consuming gas was the highest in 2010-11 at about 65 BCM. At this rate of consumption, these estimated reserves can last about 40 years. Of course, this time period will change, with any change in the gas extraction quantity, and change in gas consumption in the coming years.

The IHS study also estimates the "price signal" needed to encourage gas to be produced from the "Yet to Develop" and "Yet to Find" types of fields. These may be summarised as follows:

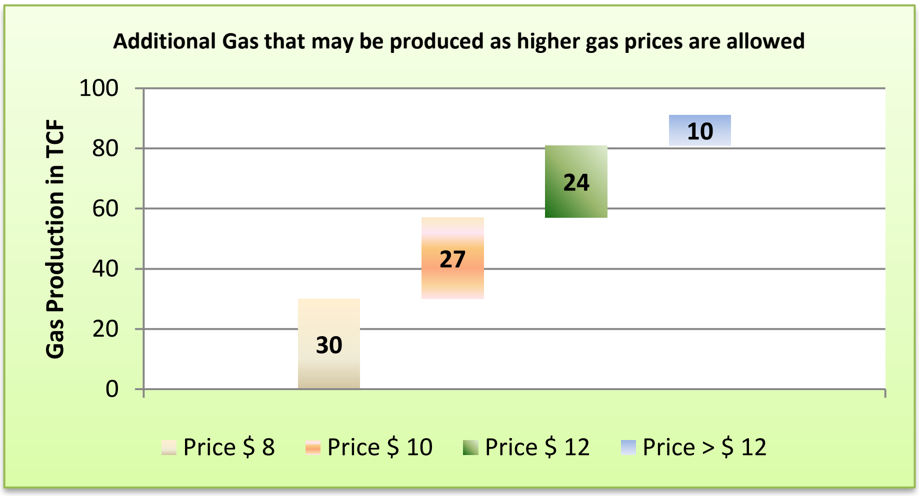
Table 16 Price Signal required for Different Types of Reserves

	Price Signal required per mmbtu				
Type of Reserve	**$ 8**	**$ 10**	**$ 12**	**Above $ 12**	**Total**
Offshore Ultra Deep:	0	10	12	5	27
Offshore Deep	8	1	12	5	26
Offshore Shallow	8	15	0	0	23
Onshore	14	1	0	0	15
Total	**30**	**27**	**24**	**10**	**91**

The conclusion drawn by IHS is that:

a. if gas price is kept below $ 8 /mmbtu, then none of this gas will be produced;
b. at gas price of $ 8, about 30 TCF will be produced;
c. if gas price is around $ 10, then additional 27 TCF will get produced, totalling 57 TCF;
d. at $ 12, an additional 24 TCF will become available, taking total to 81 TCF; and finally,
e. above $ 12, a further 10 TCF will come out, so that all 91 TCF will be produced.

Table17 Incremental Gas Production at higher gas prices

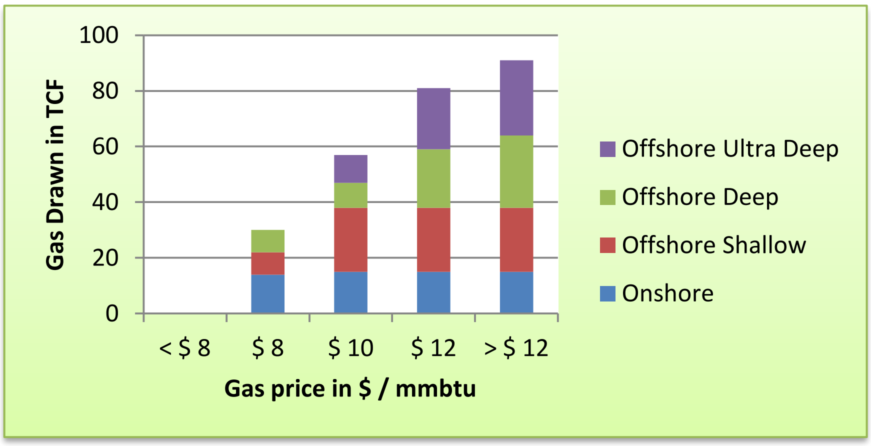


5) The figures may be interpreted to indicate that IHS believes that a minimum gas price of $ 8 / mmbtu is needed in order for any gas to be get produced from the "Yet to Develop"

discoveries, as well as to incentivise E&Pcompanies to search for the remaining 64 TCF of gas that seems to be available but has not yet been found.

6) The cumulative gas potential is forecast to be as follows, at different sale prices for gas:

Table18 Cumulative Gas Potential at various Gas Prices



7) While estimating the costs required to develop a field, the factors considered are size of the reserve, the complexity of the subsurface, the terrain, and the new infrastructure required to evacuate the gas. Each size category and terrain category was allocated a different development scenario, for which different costs and production profiles were prepared, based on historical experience, geology, and engineering parameters. IHS used its own proprietary Questor software for this purpose. Questor is a software tool for Oil and Gas industry, to estimate capital cost and operating cost analysis. It is used by over 500 oil and gas estimators and managers in 48 countries for concept screening, concept optimisation, and cost analysis. These were suitably adapted for Indian situations, including NELP concepts. Production profiles covered a 15 year outlook period.
8) As regards Unconventional Gas, the study mapped shale and coal depths and thicknesses in prospective basins, using shale/ coal quality data to assess in place resources. The volumes of Probable Recoverable Gas were estimated by comparing the risk factors (both underground and above ground) with the experience in USA.
9) The data shows that a price of $ 8 is required not only for Offshore Deep Reserves, but also for Offshore Shallow as also for Onshore reserves. Now it is well known that the cost of drilling and production activities is lower Onshore than Offshore; further, that the cost will increase with the depth of the field, so in terms of cost, Shallow < Deep < Ultra Deep. Perhaps, the high price of $ 8 is required for Onshore and Offshore Shallow reserves because they are small in size, and would fall into the "Marginal Fields" category today.

Comments on the IHS Study

Unfortunately, the component fields of the "Yet to Produce" or "Yet to Develop" category or "Yet to Find" category are not provided in the summary of the IHS report available in public domain.

The major issue with the study is the high price indicated for any gas production to take place. The highest price for gas being produced today in India is about $ 6/mmbtu. As the report has not included the "Yet to Produce" category in its price sensitivity statements, it is hoped that all the 18 TCF of gas in this category will be produced even at current prices.

Gas Reserves India overview – DGH

Out of 26 sedimentary basins, only 6 were assessed for natural gas. Out of a total area of 3.14 mil sq kms,

- about one third area is under active petroleum exploration
- 45% is in deep water and 55% is onland and shallow offshore.

NG consumption in 2012-13 was ~ 55 BCM. If all present reserves can be extracted economically, they can meet our needs (at the level of 55 BCM) for just 24 years.

There is therefore a strong need to expand the total E&P effort in order to find more reserves that may be present and are awaiting discovery. It may also be noted that it takes 7 – 10 years for commercial production to commence after hydrocarbon resources are discovered.

Natural Gas Reserves

The status as on 01 April 2012 for reserves of NG is as follows: [12]

	Figs in BCM	ONGC (Nomination)	OIL (Nomination)	Pvt / JV	Total
1	Initial In-place reserves	2,124	333	1,255	3,712
2	Ultimate Reserves	1,200	181	677	2,058

Initial In-place (IIP) reserves are the reserves estimated to be present in the reservoir. Out of this, the quantity that has a 50% probability of being ultimately recovered economically from the reservoirs is called Ultimate reserves. These are lower, since it is never possible to draw all the reserves out.

As consumption of NG is of the order of 60 BCM (reference Table 1 Natural Gas Consumption 2004-05 to 2012-13 in mmscmd, and Total BCM), the Ultimate Reserves can supply India for about 34 years if consumption remains at that level, and all reserves are extracted.

ONGC has indicated that its NG reserves as at end of March 2013 are 720 mil toe, which is about 800 BCM. These are at the 3P level, meaning that it is the sum of the Proven plus Probable plus Possible reserves. This is much lower than the figure given above by DGH.

This difference may perhaps be due to the non- deduction by DGH of the NG that has been produced / extracted.

The accretion to Ultimate Natural Gas Reserves has shown the following trend in recent years:[13][14]

Table 19 Accretion to Ultimate NG Reserves 2007-08 to 2011-12

Figs in BCM	2007-08	2008-09	2009-10	2010-11	2011-12	Total	Average/ year
ONGC	32.15	41.28	65.14	70.79	43.76	209.35	52.34
OIL	6.03	6.78	6.93	4.78	2.69	24.52	6.13
Pvt / JV	39.73	- 0.71	50.56	39.82	35.92	129.40	32.35

Total	77.91	47.35	122.63	115.39	82.37	363.28	90.82

The annual average accretion to reserves was about 1.5 times average annual consumption of NG. This is good.

Proved Reserves of NG in India are 1.3 TCM, as per BP's Statistical Review of World Energy[15]. The distribution of these Proved NG reserves, based on data from MoPNG and DGH[16], is as follows:

Table 20 Distribution of Gas reserves in India

Basins	State/Area	Reserves (BCM)
Krishna Godavari (KG) Onland	Andhra Pradesh	42.298
Upper Assam	Assam	139.824
Cambay	Gujarat	78.200
Assam-Arakan	Arunachal Pradesh	2.144
Assam-Arakan	Nagaland	0.120
Assam-Arakan	Tripura	36.046
Cauvery(onland)	Tamil Nadu	39.296
Rajasthan(onland)	Rajasthan	12.131
Total Onland		**350.059**
KG + Cauvery	East Coast	462.036
Mumbai	West Coast	420.622
Total Offshore		**882.658**
Total		**1232.716**
CBM		**97.543**
Grand Total		**1330.259**

These may undergo some change, since DGH has not yet accepted RIL's decision to cut the reserves of the major D6 field in the KG basin from 292 BCM (10.3 Tcf), estimated in December 2006 to 96 BCM (3.4 Tcf), in 2012. This will reduce total reserves by 196 BCM, which is 15% of the 1330 BCM total given above. The revised total will be 1134 BCM.

According to the US Geological Survey, about 62 TCFG (i.e. 1756 BCM), of the undiscovered gas resource is in the three provinces of offshore eastern India. This is a significant amount, and would merit a great deal of further exploration. [17]

Exploration Blocks Status

Table 21 Overview of Exploration blocks awarded in India

Exploration Round	Year	Offered	Awarded	Relinquished	Operational	Discoveries
Nomination	1960		29	1	28	4
Pre NELP	1970		27	13	14	58
NELP 1	1998	48	24	20	4	41
NELP 2	2000	25	23	19	4	9
NELP 3	2002	27	23	14	9	20
NELP 4	2003	24	20	9	11	18
NELP 5	2005	20	20	7	13	20

Exploration Round	Year	Offered	Awarded	Relinquished	Operational	Discoveries
NELP 6	2006	55	52	7	45	12
NELP 7	2007	57	41	0	41	2
NELP 8	2010	70	32	0	32	0
NELP 9	2011	34	19	0	19	0
Total		**360**	**311**	**91**	**220**	**184**

There are 84 E&P players, comprising of 45 operators and 39 non operators, currently working in India. E&P operations are spread over 19 out of 26 sedimentary basins of the country, both on-land and offshore including deep waters.

It should be noted that it takes 7 to 10 years for production to commence after a discovery is found to be of commercial significance. The most successful discovery, KG D6, was a block awarded in the first round of NELP in 1998. It started production in nine years, which is very quick in the E&P business.

Area under exploration is 2.15 million sq.kms out of the 3.14 million sq-kms of basinal area. [18]The Exploration status of the total 3.14 million sq-kms sedimentary area is: [19]

- Well explored: 22 %
- Exploration initiated: 44%
- Poorly explored: 12%
- Unexplored: 22%

Growth Plans in India

ONGC has prepared a Perspective Plan till year 2030, in which they have set various targets.[20] As it believes that considerable potential remains in Indian basins, the targets include:

- Accelerate (re)-developments to levels of 300-400 mmtoe. This includes redevelopment of
  existing fields, and development of discoveries that have not yet been developed (YTD). Ten fields have been identified for priority accelerated development.
- Unlock 450+ mmtoe from domestic YTF (yet-to-find) reserves
- Exploration for new resource types, and
- Deepwater exploration with a renewed thrust.

In order to achieve these targets, ONGC has launched 6Centres of Delivery, in order to bring together the necessary expertise:

- Mumbai: Basement exploration, with UNSW.
- Delhi: CBM
- Vadodara: Shale gas
- Chennai: High Pressure /High Temperature fields, with Blade Energy
- Unconventional plays: with Schlumberger
- Deep water - under process[21]

ONGC has also formed alliances with

- Conoco Phillip in Mar'12 for Deepwater and Shale gas,
- Eco-petrol for jointly studying the fan-belt traps of Cachar Region in India & for cooperation in developing EOR/IOR technologies

It has also set in place a rigorous stage gate process for project evaluation and monitoring.

ONGC has envisaged an investment of Rs 265,000 crores during the 12th Plan period 2012 - 2017. For the Perspective Plan till year 2030, the total investment proposed exceeds Rs. 11,00,000 crores during the period 2013-2030.

These factors provide some optimism that more NG will become available in the country for power and fertiliser sector growth.

E&P Hurdles – some examples

One of the criticisms of the E&P policy is that it has not been able to attract many of the major companies such as Shell, Exxon Mobil, Chevron, etc. An idea of why this is the case can be obtained from the following examples:

- BHP Billiton: has given up all its blocks, except one, since all its other blocks of the Mumbai Basin are inside Naval exercise area, where E&P activity is not feasible.
- M/s BP relinquished Block KG-DWN-2005/2, as the DRDO and Navy placed 70% under "No Go" area.
- ENI is unwilling to drill in Block AN-DWN-2003/2 in absence of clear permission from the Department of Space.

When the companies are awarded the blocks, they have to commit a Minimum Work Programme to be completed within a stipulated time, failing which penalties have to be paid. In these cases, the companies would have spent enormous amounts on pre-bid, bid and post-bid activities, and made no headway. Often, their requests for condonation of delay are not accepted.

At another level, there is a public tussle between the GoI and RIL about the Cost of Petroleum to be charged.

As will be seen later in the report, there are also issues about getting approval for the price at which NG may be sold, and the procedure for doing so.

Rangarajan and Kelkar Committees

To deal with some of these issues, the Rangarajan committee was formed to look into the terms of the Production Sharing Contract; it has recommended some changes, which have by and large been welcomed by the E&P community. The NG pricing recommendations however, have not gone down well with customers.

Another committee was formed in Feb 2013, headed by Dr Vijay Kelkar, to advise on steps for

- enhancing Oil & Gas production from Conventional and non- Conventional sources
- appraisal of India sedimentary basins to reach 75% by 2015 and 100% by 2025,
- Acquisition of acreages abroad for E & P,
- Import of gas, including through transnational pipelines,
- Development of gas transportation infrastructure for establishing a countrywide market place, and
- Roadmap for switching to market determined gas pricing by March 2017

The report is awaited. It is hoped that it will address some of these issues.

Unconventional Resources

In addition to the conventional resources of NG, there a number of Unconventional Resources that can play an important role in tomorrow's supplies of NG. These are Coal Bed Methane (CBM), Shale Gas, Underground Coal Gasification (UCG), Petcoke Gasification, and Gas Hydrates. These are discussed below.

Coal Bed Methane

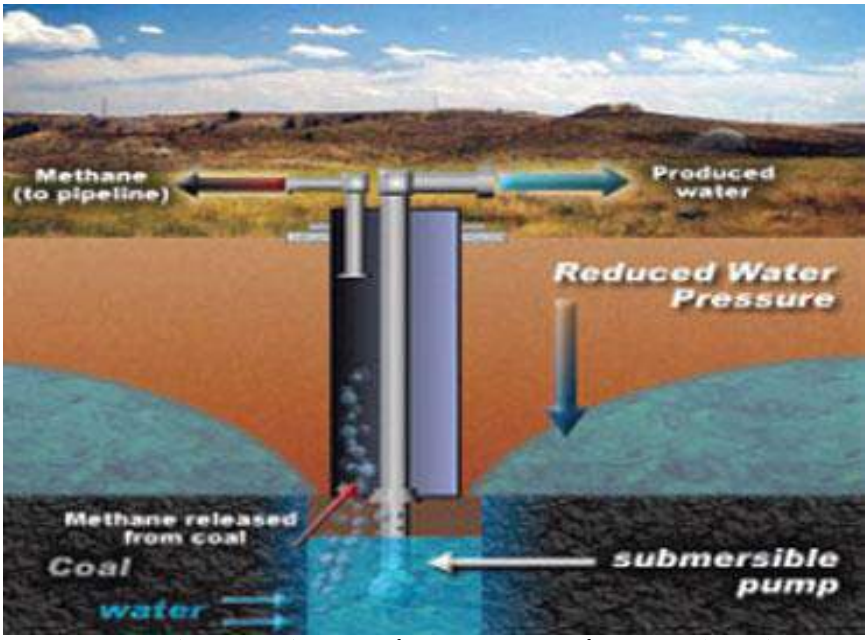


Figure 2 Schematic diagram for extraction of Coal Bed Methane

Methane gas is formed as part of the geological process of coal generation, and is contained in varying quantities within all coal. It causes safety problems, and has to be removed before mining starts. It is now recognised as a valuable material that has commercial value, rather than just a hazard to be neutralised.

As India has the 4th largest proven coal reserves in the world, there are significant prospects for large quantities of NG becoming available from the exploration and exploitation of CBM.

Coal bed methane is often exceptionally pure (over 90 percent methane),as compared to conventional natural gas, containing only very small proportions of "wet" compounds (e.g., heavier hydrocarbons such as ethane and butane), and other gases (e.g., hydrogen sulfide and carbon dioxide).
From the earliest days of coal mining, the flammable and explosive gas in coalbeds has been one of mining's paramount safety problems.

Only a small part of the coal bed methane is present as "free" gas within the coal seams; most of it is adsorbed to the coal.

The first step in CBM production is the high-pressure injection of fracturing fluids and proppant (such as sand) into targeted coal zones. These enlarge existing fractures in the coal seam, or induce new fractures, which improve the connections of the production well to the fracture networks in and around the coal zone. Then groundwater and injected fracturing fluids are pumped out from the fractures in the coal zone to reduce pressure in the formation. When pressures are adequately reduced, methane desorbs from the coal matrix, moves through the network of induced and natural fractures in the coal toward the production well, and is extracted through the well and to the surface.Coalbed methane is produced at close to atmospheric pressure. The proportion of water to methane pumped is initially high and declines with increasing coalbed methane production.[22]

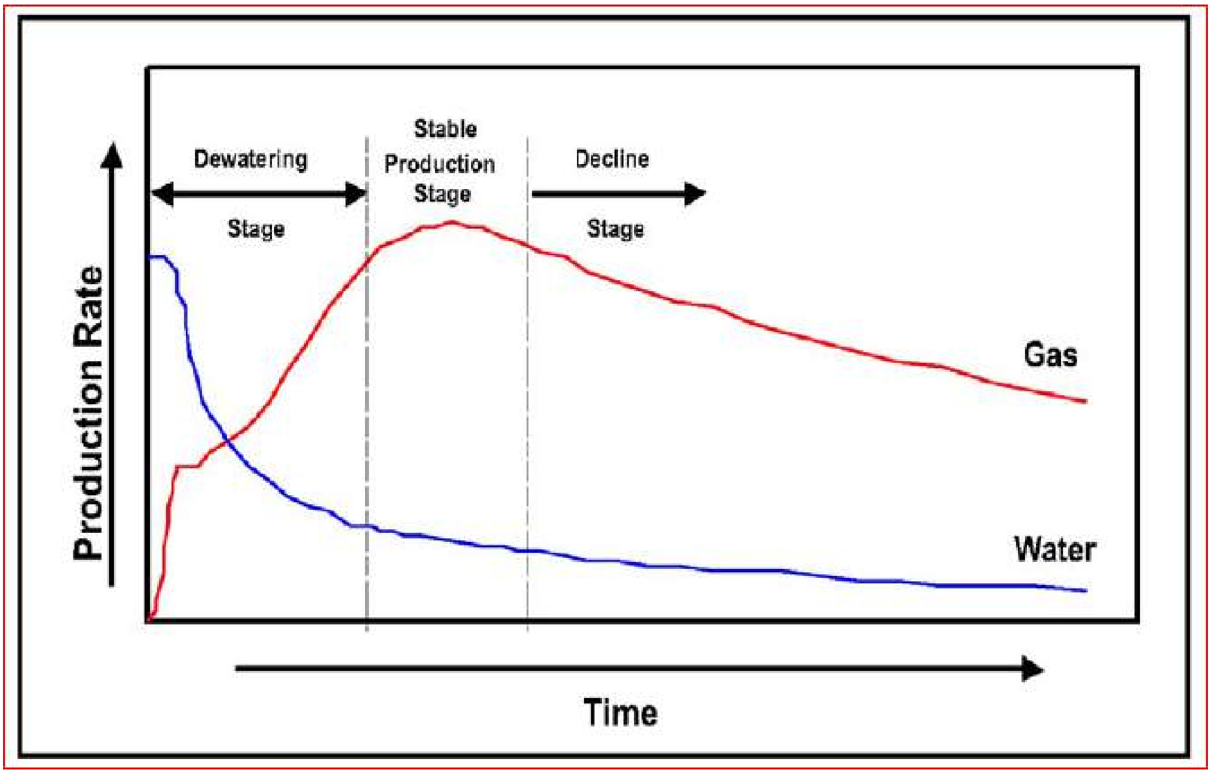


Figure 3 Production of Water and Methane over time from CBM well

A large number of wells is required to be drilled, as the output per well is small, such as a few thousand standard cubic metres per day. As the wells tend to produce for many years, the cumulative quantity is large.

A broad guideline about the exploitation of coal seams is as follows:

Table 22 Coal exploitation guidelines

Depth of Coal Seam	Method	Output	Ministry concerned
Upto 300 metres	mining	Coal	Coal
300 to 600 metres	CBM	Methane	Petroleum and Natural Gas
Beyond 600 metres	Underground Coal Gasification	Syngas	Petroleum and Natural Gas

There are two factors that play a role in these depth guidelines:

- The greater the depth, the more is the adsorption of methane on coal. In shallow seams the methane is relatively mobile, and difficult to capture. So, CBM starts after a certain depth.
- However, the energy required to pump water up from the mine increases with depth. So, beyond some depth, CBM is no longer workable.

As a general principle, the energy spent on extracting any energy resource should not exceed the amount of energy extracted.

DGH estimates total CBM reserves at 4.6 TCM, compared to Russia 114, China 32, and USA 12. This level of 4.6 TCM is four times that of conventional gas at 1.13 TCM

ONGC however estimates CBM potential at over 12 TCM.[23]
IHS CERA estimates that the Gas in Place Resources are 158 TCF for CBM.

GoI / MoPNG has conducted four rounds of competitive bidding for CBM blocks till now.

Table 23 Bidding Rounds held for CBM

	Round 1	Round 2	Round 3	Round 4	Total
Year	2001	2003	2006	2010	
Blocks Awarded	8	8	10	7	33
Estimated Resources BCM	393	427	635	330	1,786
Production expected mmscmd	13.5	9.5	Na	Na	38
Producing blocks	5 est.	-	-	-	5 est.

Source – book on CBM published by Infraline [24]

The above table shows that DGH estimates that 1786 BCM of resources from the blocks awarded till now can yield 38 mmscmd of NG. As DGH has estimated India's total CBM potential at 4.6 TCM, then the total NG output from all the national CBM resources could yield about 98 mmscmd of gas.

If ONGC's estimate of 12 TCM is considered, then the NG output would rise to 255 mmscmd.

Clearly, CBM has the potential to be a major supplier of NG in the future, much more so than conventional gas.

In addition, there are 19 CBM blocks on land with Coal India Ltd for coal mining. [25]

Coal and methane are two different energy sources lying in the same blocks but are regulated by different agencies. While the coal ministry allows the mining of coal, the oil ministry regulates methane gas production. This overlap of jurisdiction may soon be settled: MoPNG has proposed that these blocks may be developed by CIL (and / or its subsidiaries WCL, SSCL, ECL, etc.)[26]; however, the pricing and allocation of the gas produced would have to be as per the directions of MoPNG.

Figure 4 Map of CBM Blocks awarded in Rounds 1 to 4

From the table above, the Estimated Resources and Production expected figures given by DGH can be used to estimate the average recovery rate considered by DGH. The total gas that would be produced from the blocks that have been allotted is estimated at 38 mmscmd by DGH. As the licence to operate the blocks is given for 25 years, we may safely assume that the blocks will produce for 20 years; further assume that they will produce for 350 days in a year, with 15 days for downtime. Thus, over their entire lifetime, these blocks could produce: 38 mmscmd * 350 days/year * 20 years = 266,000 mil scm of gas, i.e. 266 BCM. As DGH has estimated the resources from these blocks at 1,786 BCM, it appears that the recovery ratio is estimated at: 266 / 1786 = 14.8%, say 15%.

It is hoped that this low recovery rate will increase with experience. Discussions indicate that some CBM operators envisage recovery rates exceeding 50% of the gas initially in place. The benefits of raising the recovery ratio are indeed enormous, and should provide adequate incentive for operators to reach high recovery levels.

A major player is Essar Oil. It estimates that it has over 10 TCF (283 BCM) of reserves and resources spread across five blocks in Madhya Pradesh. It plans to invest over $500 million in the sector over the next 5 years[27]. From its Raniganj block, it estimates peak production of about 3.0 mmscmd, for which about 500 wells will be required[28].

This large production is the basis for the biggestdownstream investment based on CBM, whichis occurring at Asansol, West Bengal where Matix Fertilizers & Chemicals Ltd, is setting up an Ammonia / Urea complex, in two phases:

Phase 1: 2,200 tpd Ammonia plus 3800 tpd Urea. Start up scheduled for 2016. The plant has reached an advanced stageof mechanical construction. However, drilling of required wells for extracting CBM is held up due to delay in various clearances. The investment in the Ammonia / urea complex is estimated at Rs 5,000 crores.

Phase 2: Doubling proposed with higher capacity plants of 2530 tpd Ammonia and 4430 tpd urea, at another estimated Rs 5,000 crores, as inflation may offset the savings of a brownfield expansion.

The MoPNG had raised an objection that the CBM producer, Essar Oil, should have invited open bids through an auction process for the sale of gas, instead of entering into a direct deal with Matix. However, the parties contended that the NG was being utilised for producing fertilisers, namely urea, which have been accorded highest priority in the allocation of gas. Further, the sale price of gas was set at the level of $ 4.2/ mmbtu determined by the Government for other producers. So this objection is not likely to hamper the project.

CBM Well Drill Rig of ESSAR

CBM Gas / Water Separation Facilities of RIL

Figure 5 CBM operations

Another CBM project that is progressing is that of M/s Reliance Industries Ltd who operate the block SP (West)-CBM-2000/1 and block SP (East)-CBM-200/1 awarded to them in Round 1 of CBMbidding. These blocks are located within the districts of Shahdol andAnnupur in the state of Madhya Pradesh. Production of gas was expected to commence by second half of 2014,subject to necessary approvals.The estimated peak plateauproduction is upto 3.5 mmscmd. A pipeline would have to be constructed to connect the field to Gail's HVJpipeline 100 kms away. As this line is connected tothe national pipeline network, the gas could be available to customers anywhere on the network.

ONGC is operating 4 CBM blocks - Jharia, Bokaro, North Karanpura & Raniganj. It is bringing in additional partners in a bid to speed development. It has been established that in-place reserves of 76 BCM; Field Development Plans have been submitted for the blocks, and approvals are awaited. ONGC has planned investment of Rs. 5,000 crores.[29]

Assuming a 15% recovery ratio, and 20 years life, these reserves could produce about 7 mmscmd of NG. This is indeed a significant volume of production, and would add about 4% to the annual output at current levels.

Great Eastern Energy Corporation (GEEC) has developed the Raniganj block in West Bengal, with an estimated gas potential of 27 BCM. [30]It produces about 0.57 mmscmd presently; the output is scheduled to rise to 3 mmscmd after all 300 wells are completed in next few years. [31]

The foregoing shows that CBM could add significantly to the NG production in the country.

Discussions indicate that each well requires about 50 to 150 acres land, depending on the local situation. The number of wells is also large - about 100 - 150 per mmscmd of output. The water requirement is large initially, at about 50 - 100 m3 per day per well, and reduces later to about one- tenth.

The progress of exploration and production is hampered by land acquisition issues, water availability, as well as conflict with Coal mining, etc.

Shale gas in India

Shale sands have been known for a long time. They have shot into prominence after the technology was developed in USA for commercial exploitation, and has been a game changer in the global oil and gas sector.

ONGC was the first to establish Shale gas presence in India. A Pilot Project in Damodar valleyestimated the resource there to be about 35 TCF with 8 TCF recoverable. [32]These are large numbers. If drawn over a period of 15 years, then it could average 40 mmscmd. A few more such projects could indeed make a large difference to the NG scenario in India.

ONGC plans to explore Cambay, Cauvery, and Bengal basins in alliance with ConocoPhillips. ONGC estimates the potential at 2 TCM of gas.[33]

This is more than the reserves of conventional gas at 1.33 TCM. Shale gas therefore merits close attention in India.

- There are various estimates for the shale gas resources in India. EIA USA (Apr'11) has reported a GIP concentration of 1170 TCF, risked gas-in-place of the order of 293 TCF, and recoverable level of 69 TCF from 4 Indian basins
- USGS (Jan'12) has estimated 6.1 TCF as technicalrecoverable in 3 Indian basins and mentions potential for Shale oil. [34]
- As part of a global study for the US Energy Information Administration (June 2013), the Advanced Resources International Inc. (ARI) assessed four priority basins. The study seems to be an evaluation of publicly available data. It notes that the data is limited, and the basins are geologically highly complex. Within these limitations, their estimates are as follows:

Table 24 Shale Resources as per US EIA / ARI June 2013

	Basin	Risked In-place resource	Technically recoverable resource
1	Cambay	146	30
2	Krishna Godavari	381	57
3	Cauvery	30	5
4	Damodar	27	5
	Total	584	97

- IHS - CERA (May 2013)studied the basins of Cambay, Cauvery, Krishna - Godavari and Assam Shelf, and concluded that the Gas in Place Resources are 586 TCF for Shale Gas.

Dr. V. K. Rao, who retired from DGH, notes the wide range in estimates of recoverable shale gas[35]:

USGS USA	EIA USA	McKinsey	Petrotech Veterans forum	NGRI
6	97	100	130	260

Dr. Rao's own judgment is at the level of 120 TCF. Even if one considers a slightly conservative level of about 100 TCF for our purposes, it amounts to about 2.8 TCM, which is double the Conventional resource estimated at 1.33 TCM. Clearly, Shale gas is worth exploring in detail.

Available data indicates that following sedimentary basins should be explored for Shale gas:
- Cambay Basin
- Gondwana Basin
- KG Basin
- Cauvery Basin
- Indo-Gangetic Basin
- Assam Arakan Basin

In addition, ONGC & CMPDI have taken up the task of identifying prospective areas of another 6 Basins / sub basins.

A map showing the sedimentary basins in the Indian sub-continentthat may have Shale gas is given below. [36]

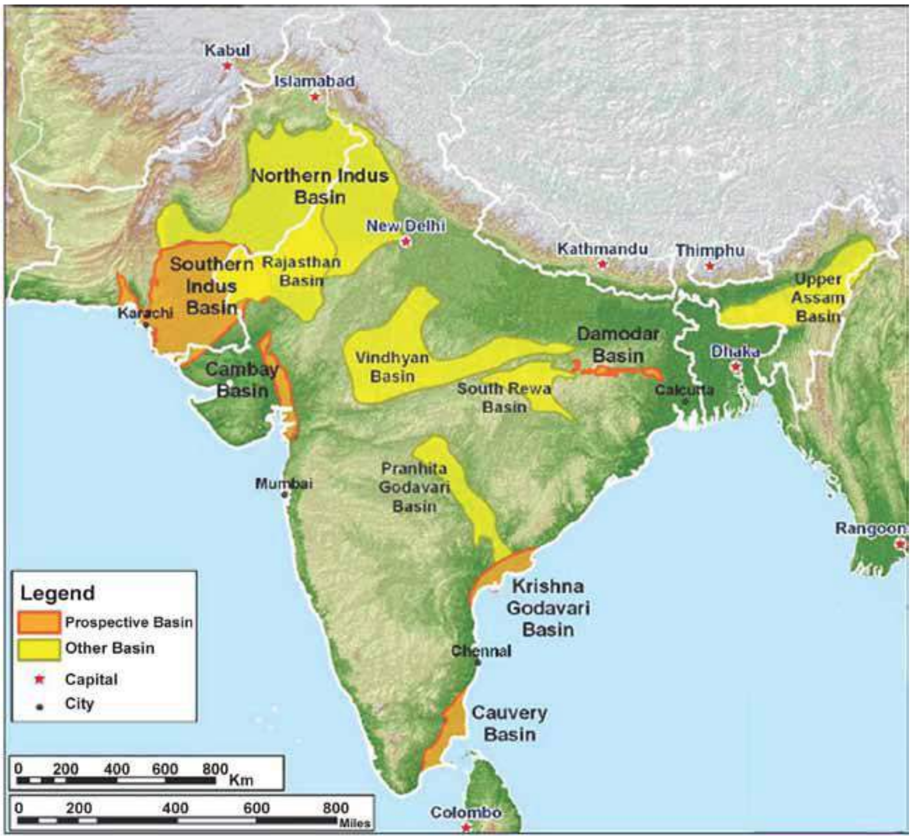


Figure 6 Sedimentary basins in india having Shale gas

ONGC conducted an R&D project to explore for Shale Gas in Gondwana Basin in two existing CBM Blocks. On drilling 4 Pilot wells, presence of gas was discovered.

A Multi Organizational Team of DGH, ONGC, OIL, GAIL has been formed by MoPNG to suggest the methodology for Shale Gas development in India.

The government of India is in the final stages of formulating the Shale Gas policy. This may require some amendments in P & NG Rules.

The major steps to be completed before commercial supplies begin are broadly:

i. Carving out and Offering of Blocks, based on availability of all necessary clearances and finalization of Shale Gas policy.
ii. Selection of parties and signing of agreements
iii. Environmental and other approvals for conducting exploration
iv. Assuming that commercial quantities of economically recoverable reserves are found, approvals for taking up development of the reserves
v. Obtaining approval from the government for price and allocation to customers as per the extant priority policy.
vi. Arranging for pipeline connectivity to evacuate the gas to consumer centres. Or, attracting user industries to the location, and getting the necessary approvals for them to set up their units.

ONGC, which has been in the forefront of efforts till now, has recognised two major operational issues:

- the local population may resist use of their land for drilling operations ,and
- availability of huge water resources required. [37]

It is estimated that all these steps will take several years, and there will be no real availability before the end of this decade.

TERI also cautions that the country may not be able to exploit shale resources, since the water requirements are large, which the country may not be able to spare, as India is already a water-stressed country, and is fast approaching the scarcity benchmark of 1,000 m3 per capita. Further, many of the potential shale gas bearing areas, such as Cambay, Gondwana, Krishna-Godavari, and the Indo-Gangetic plains are also areas that will experience severe water stress by 2030. It is therefore suggested that priority has to be given to conserving water resources, which is life giving, and seeking alternate means for developing NG resources[38].

It is also important to place the findings of the IHS study, mentioned above. It also covered two forms of Unconventional Gas, namely Shale Gas and Coal Bed Methane [CBM].

The basins studied were as follows:

Table 25 Basins studied for Shale Gas and CBM

Shale Gas		CBM
Cambay		Satpura
Cauvery		South Reva
Krishna - Godavari		Damodar
Assam Shelf		Assam Shelf
		West Bengal
		Mahanadi
		Pranhita - Godavari

The study concluded that the Gas in Place Resources are 586 TCF for Shale Gas, and 158 TCF for CBM, totalling 744 TCF. Of this, the unrisked Potential Recoverable gas is estimated at only 26%, i.e. 196 TCF. They further estimate that the Probable Net Recoverable gas is only 15 TCF, and that too at a gas price of about $ 15 / mmbtu. The medium case production estimate is for 1.1 BCF/day, i.e. 31 mmscmd by 2035, of which Shale gas would be 95%.

Thus, the Net Recoverable gas is just 2% of the Unconventional reserves. IHS compares the Shale gas resources in USA with those in India to explain the poor recovery factor:

Table 26 Shale Gas – Comparison between USA and India

	Aspect	USA	India
1	Mineral Rights	With landowner, who has incentive to provide access to land in return for share of earnings from the minerals	Not with landowner, leading to access difficulties
2	Location of unconventional resources	Most are in low land use areas	Most are in intensive agricultural areas
3	Water availability in resource areas	High	Low
4	Approval procedures	Fast Track large scale development plans allowed	Complex – will cause long delays
5	Development status of: – Service sector – gas pipeline infrastructure – E&P sector	Mature	Developing

Thus, even though Unconventional reserves are much larger than the Conventional reserves, the low recovery factor for Unconventional reserves leads IHS to conclude that India will have to depend on extracting as much as possible of the conventional gas, whose recoverable estimate is six times higher at 91 TCF.

Underground Coal Gasification (UCG)

In this process, coal buried deep underground is burnt in oxygen deficit environment and in presence of steam to generate Syngas, whichisthen brought to the surface for use. In order to sustain the burning, air / oxygen and steam has to be sent underground through pipes into the coal bed, and ignited. Another pipe is then provided to bring the gases above ground. The process of burning causes syngas to be produced, which is a mixture of Carbon Monoxide, Carbon Dioxide and Hydrogen. It should be noted that when NG is burnt, a similar mixture is formed.

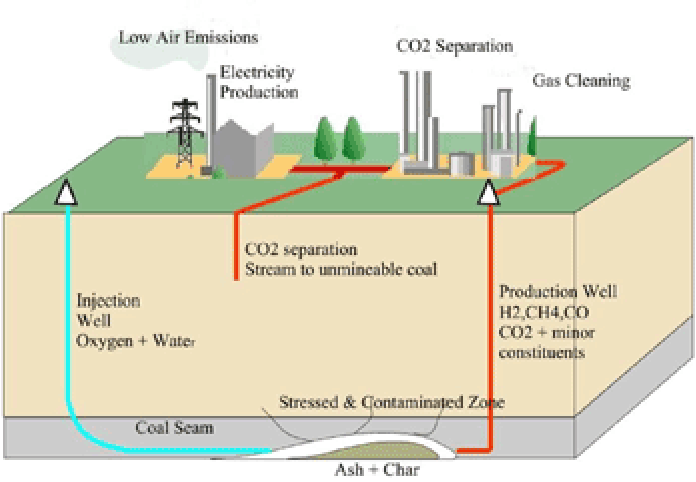


Chart 6 Schematic diagram for Underground Coal Gasifcation [39]

The advantage of the combustion occurring underground is that:

- No Gasifier has to be provided,
- No Coal Supply, Transport, Storage, Preparation and handling are required
- the ash and slag remains there, and does not create a disposal problem.

The maximum experience of UCG is with the FSU, where over 15 mil tonnes of coal has been gasified since 1950s. The combined experience in Australia, Europe and US is less than 100,000 tonnes.

The coal resources of India according to depth of occurrence are as given below[40] :

Table 27 Domestic Coal Resources by depth, in billion tonnes

Depth -wise (metres)	Proved	Indicated	Inferred	Total	%
0– 300	91.92	71.46	10.76	174.14	59.33
300– 600	11.04	58.42	16.26	85.72	29.21
0 – 600 (Jharia coalfield only)	13.71	0.50	0.00	14.21	4.84
600 – 1200	1.47	11.79	6.17	19.43	6.62
Total	118.14	142.17	33.19	293.50	100.00

Of the total coal reserves in India, about 1.5 billion tonnes is at a depth more than 600 metres. It is technically not feasible to mine these resources. UCG is one way to utilise them in situ.

Typically, coals of low rank, e.g. lignite and sub-bituminous, are the easiest to gasify,hence better suited for UCG. India has about 36 billion Tonnes of lignite resources, much of which is at relatively deeper depths or constrained by one or more factors for commercial mining. Thus, deposits which are otherwise deemed uneconomical could be exploited through UCG. [41]

Even the resources in the 300 to 600 metre zone can be utilised for UCG. They are presently earmarked for CBM. After the Methane is extracted, the coal lying there can be gasified as UCG. This would open up 8 times more resources at the Proven level.

Additional exploration will enable upgrading of some of the Indicated and Inferred resources to Proven category in both the 300- 600 metre group as well as the 600 - 1200 metre group. If say 30% of these resources move upto Proven category, they will provide another 27 bil tonnes for exploitation. To this can be added the Proven resources of 1.47 bil tonnes in 600 - 1200 metres depth, and the 11.04 bil tonnes in 300-600 metre depth, giving a total coal resource of about 40 bil tonnes that may be available for UCG.

NTPC had studied the subject of generating power from UCG in 2006. They estimate that the coal required by a 100MW plant for 30 years as 15 million Tons. If the usable resource of coal for UCG purposes is 15 billion tonnes, then it should suffice for 100,000 MW for 30 years.This is a large quantity, almost half of present total installed capacity.

Since UCG requires drilling expertise, ONGC is also active in this field. It has undertaken pilot studies with some Russian research institutes. It has identified the Vastan block in Gujarat for UCG exploration, and has applied for award of Mining Lease (ML), for the UCG pilot project from the Ministry of Coal.[42]

Based on its studies, ONGC estimates the UCG potential at a massive 195 TCM of gas. [43] This is 150 times the 1.3 TCM of conventional gas resources.

Clearly, these resources are large enough for providing a substantial chunk of our energy requirements - provided the technology is mastered. It would be worthwhile to have Technology Missions to master the multi-disciplinary issues involved so that a steady continuous supply of gas is maintained.

According to the UCG Association, power cost from UCG is less that other from other fuels.[44] These figures certainly need verification.

There is interest elsewhere also in this technology, especially in countries with large coal reserves. A recent news item states thata South Africancompany, CDE Process, is using its third-generation underground coal gasification (UCG), design for a 50 MWe power project in South Africa. CDE Process is responsible for the design, implementation, execution and management of the project, with the first phase aiming to provide power to the national grid by 2016.[45]

It should be noted that water is also required here to transport the gas to the surface from 600 + metres under the ground.

Petcoke Gasification

India has about 16 mil tpa of capacity of petcoke, of which 6 is with Reliance's Jamnagar refinery, and rest with other refineries at various places in India. For example, IOC's upcoming refinery at Paradeep will have capacity to make 1 mil tpa of petcoke. Similar capacities are / will be available at BPCL's Kochi refinery, and MRPL's refinery at Mangalore. Refineries are adding coker capacities in a bid to extract the maximum petroleum from crude, and to reduce the sulphur content in their other products.

It is well known that petcoke can be gasified to generate syngas, which can be used to make chemicals such as ammonia, methanol, and others. RIL has embarked on a major project for gasification of petcoke to make a variety of chemicals.

Syngas can also be burnt to generate power and steam. Examples are available from many parts of the world. Indian industry can also examine the viability of this option.

GE provides an example of gasifying one million tonnes of petcoke like residue to generate 550 MW power, steam of about 800,000 tonnes/year, and 316 mmsm3 of Hydrogen. All these could be used in the refinery.[46]

The principal consumer for petcoke is the cement industry, but reports indicate that it may not be able to absorb all the petcoke produced in the country, partly because the logistics is not favourable when the petcoke production location is far from the cement producing locations.

A possible opportunity may arise because the main determinant of the cost of petcoke is crude oil, whose price may decline in coming years, as mentioned above. On the other hand, the prices of domestic coal and gas are set to rise in the coming years. Availability can also be a constraint. Thus, the comparative costing may tilt in favour of petcoke.

Gas Hydrates[47]

Gas Hydrates are formed when molecules of natural gas, typically methane, aretrapped in ice molecules. Hydrates form in cold climates, such as permafrost zones and in deep water.

Global reserves are said to exceed all the other fuel sources combined.

First successful extraction of methane on experimental basis was reported earlier this year from Japan. To date, the economic liberation of hydrocarbon gases from hydrates has not occurred, but hydratescontain quantities of hydrocarbons that could be of great economic significance.

The Directorate General of Hydrocarbons (DGH), coordinates the National Gas Hydrate Program (NGHP), under the guidance of the Ministry of Petroleum and Natural Gas.The NGHP is a consortium of NationalE & P companies, namely ONGC, GAIL, OIL and national research institutions NIO, NIOT and NGRI.

During the period 1998 to 2003, data of various offshore Basins were studied by ONGC for assessing Gas Hydrate prospectivity. Based on this data, the first NGHP expedition was launched in 2006 wherein 21 sites weredrilled/ cored in Indian offshore. This discovered one of the richest known marine gas hydrate accumulations yet (KG Basin), as well as one of the thickest and deepest (612M) gas hydrate occurrences yet (Andaman Islands).

Two more expeditions are planned.

Early studies prognosticate the gas hydrate resources of India at a staggering level of 1,894 TCM. The USDOE in Feb 2012 estimated that the concentration of gas hydrate in sands within the gas hydrate stability zone is 933 TCF, or 26 TCM. Even this number is 20 times the conventional reserves mentioned above at 1.33 TCM.

There is global interest in Gas Hydrates, as they occur in many parts of the world. Progress in actually liberating the methane and trapping it successfully for use is, however, very slow. There is also concern that if the methane flows unchecked into the atmosphere it will have a strong green house effect, since it is 22 times more potent than CO_2.

The NGHP is moving forward with the help of various research and technology institutes in the country and abroad, especially US agencies. However, it may be noted that the Steering Committee of the NGHP held its 15th meeting in October 2013, after a gap of 3.5 years.

Summary of Domestic Resources

The above information is collated here.

Summary of Resources position of Conventional NG

The various estimates given above are summarised below:

IHS CERA (April 2013):	Yet to Develop	24 TCF = 680 BCM
	Yet to Find	67 TCF = 1,898 BCM
	Total Potential	91TCF = 2,578 BCM
DGH (April 2012)	Initial In-place reserves	3,712 BCM
	Ultimate Reserves	2,058 BCM
IndianPetro Group	Proven reserves	1,330 BCM
BP's Statistical Review	Proven reserves	1,330 BCM
US Geological Survey	Undiscovered resources	1,756 BCM

The foregoing shows that USGS and IHS CERA have similar estimates for the additional resources that may be discovered. At about 1800 BCM, they are about 40% more than the Proved Reserves of 1330 BCM.

Global standards for reporting

It appears that India has not adopted global standards for reporting of petroleum resources. These will ensure that the globally accepted criteria are used for describing resources, and for quantifying them.

Summary of Resources from Un Conventional NG

CBM potential	IHS CERA	4,475 BCM
	DGH	4,600 BCM
	ONGC	12,000 BCM
Shale gas	ONGC	2,000 BCM
	US EIA / ARI	16,540 BCM Risked In-place resource
		2,750 BCM Technically Recoverable
	IHS CERA	16,600 BCM Gas in Place Resources
UCG	ONGC	195,000 BCM
Petcoke	small	
Gas Hydrates	US DoE	26,000 BCM

It is seen that the Unconventional resources are much larger than the Conventional ones. From the standpoint of energy security, it would be worth investing major resources in developing these.

Estimate of Future Production

M/s ICRA has estimated the future gas production as given below. It includes some output from CBM, but none from either Shale gas or UCG. [48]

Table 28 Estimate for Future Gas Production (in mmscmd)

	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25
ONGC Nominated	65	65	66	73	80	80	80	80	76	73	69	65	62
OIL Nominated	7	7	8	8	9	9	9	9	9	9	9	8	8
RIL- KG D6/ Sat/NEC	26	14	15	15	15	24	26	31	38	38	38	38	38
GSPC- KG	0	0	2	2	3	4	4	4	4	5	5	5	5
ONGC-KG/Mahanadi	0	0	2	5	10	13	18	18	18	18	18	18	18
Other small fields	13	10	11	12	13	13	12	12	11	11	11	10	10
CBM fields	0	0	1	2	3	4	5	6	7	7	7	7	7
Total	**111**	**96**	**105**	**117**	**133**	**147**	**154**	**160**	**163**	**161**	**157**	**151**	**148**

If these numbers do materialise, unlike the experience in the recent past, then there is some hope for the power and fertiliser sectors, at least as far as quantity allocation is concerned. Affordability will be discussed later.

Overseas gas blocks

In order to ensure access to oil and NG, ONGC Videsh Ltd. has been formed as a subsidiary of ONGC to focus on acquiring and developing petroleum assets overseas, with a view to bring the products to India. OVL has till now obtained substantial reserves across ten countries, as of 31 March 2013:

Table 29 OVL Reserves

Category	BCM	Remark
P1	92.29	Possible amount, in addition to amounts below
P2	47.11	Probable amount, in addition to Proved amount
P3	19.51	Proved amount
Total	158.91	

Many Indian companies have invested in blocks overseas

- – RIL – large investment in US shale,
- – BP/Videocon/ OVL in Mozambique
- – BP/Videocon in Brazil
- – Gail in many parts of world

- Any gas found there can come to India only as LNG or by pipeline. It will be priced as per international norms
- Gail could not bring gas from Myanmar as Bangladesh did not permit a pipeline across its territory

A major acquisition has occurred in Mozambique, which is on the eastern coast of Africa, and therefore at a comparatively short distance from India. OVL and Oil India Limited (OIL) jointly signed definitive agreements with Videocon on June 25, 2013, to acquire 10% Participating Interest in Rovuma Offshore fields in Mozambique 1(Area 1), followed by ONGC signing a definitive agreement with Anadarko to acquire a further 10% stake in the project on August 24, 2013. Area 1 is the largest gas discovery in offshore East Africa, with recoverable reserves ~ 35 to 65 TCF. It has the potential to become one of world's largest LNG producing hubs;first LNG is expected by 2018.

OVL now has 32 Projects in 16 Countries, of which 14 are at the Exploration stage, 5 at the Development stage, and 11 are producing; 2 more are for pipelines. It produces about 3 BCM of NG overseas, which is too small a quantity to bring to India.

Reliance Industries Ltd. (RIL) has invested about US$ 3.5 billion in the Marcellus and Eagle Ford shales in USA through joint ventures with Chevron, Carrizo, and Pioneer. Marcellus has been described as the largest discovered unconventional gas field in the US; with estimated net recoverable resources of 318 trillion cubic feet (TCF) it is one of the largest worldwide, and is about 8 times as much as all the reserves in India. According to RIL's Annual Report for 2012–13, the break-even cost of shale gas production in the US is as low as US$ 3.50–4.00 per mmbtu. RIL's revenues from the shale gas business more than doubled to US$ 545 million in 2012 as compared to 2011. [49]It is hoped that RIL will bring the technology and experience gained there to explore for shale gas in India.

Oil India Limited (OIL), Indian Oil Corporation (IOC), and GAIL India Limited have also made investments in shale gas production in the US.

LNG as supplement to domestic gas

Since there is a shortage of domestically produced NG, the obvious alternative is to import the shortfall. Doing so is not simple, since there is a fundamental difference between NG and other commodities and its alternatives, such as crude oil, fuel oil, naphtha, coal, etc.: NG is a gas, at ambient temperatures, whereas the others are liquids or solids. A gas, by its very nature, occupies a large volume. Further, the physical properties of Methane are such that it becomes a liquid only at a very low temperature of (-)162 deg C at atmospheric pressure; if it is to be liquefied at room temperature, then it needs to be compressed to a very high pressure of about 320 bar. NG is also highly inflammable.

Thesefacts make the logistics of handling, storing and transporting NG very different, complicated and expensive. For consumers located at a distance from the gas fields, NG has to be transported to them, using special techniques. Unlike LPG, road transport is not a large scale option for NG. Where the route is entirely over land, pipelines are used that operate under pressure, since gas flows only from a zone at higher pressure towards a zone at lower pressure.

The transport over sea is possible only by major reduction in the volume occupied by NG, which is achieved by cooling NG to (-)162 deg C making it into a liquid ("Liquefied NG" = LNG) that occupies 600 times less volume, at atmospheric pressure. Thus, the import of NG by sea is always in the form of LNG.

LNG chain

The LNG business is complex and expensive. It can function only when all elements in the chain are available and functioning properly.

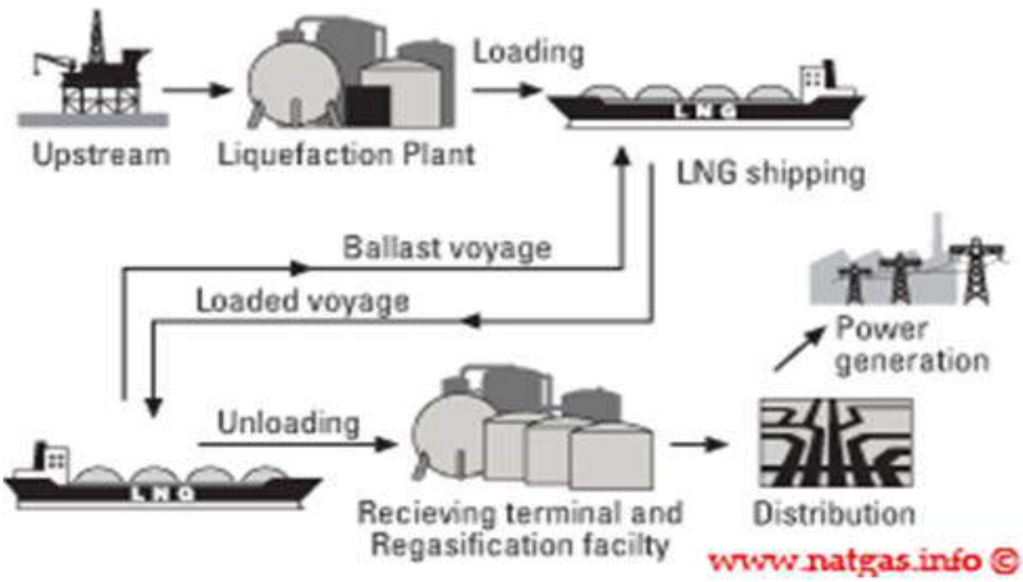


Figure 7 LNG Complete chain

A Liquefaction plant requires a steady un-interrupted stream of Natural Gas for efficient operation.

It is normally located as near as possible to the gas wells (called "Upstream" in above figure). At the Liquefaction plant, the input NG is cleaned, and cooled to cryogenic temperature of (-)162 deg C, making it into a liquid ("Liquefied NG" = LNG), that occupies 600 times less volume. It is then loaded onto special LNG tankers that can maintain the low temperature for NG to remain in liquid state. The cargo is unloaded into a Receiving terminal, again at the(-)162 deg C temperature. The LNG is then re-gasified under controlled conditions, and then distributed to customers through Pipelines.

It may be noted that in the case of domestic NG, the steps of Liquefaction, Cryogenic shipping and Re-gasification are not required. Hence, domestic gas is always much cheaper than LNG.

Investment structure LNG chain

The Upstream reserves of NG have to be large to support a Liquefaction plant, since this process is viable only at large volumes: the average capacity of 24 LNG trains commissioned all over the world in 2006-2012 was 4.9 million tonnes per year.[50]The NG supply required to feed a 5 mil tpa LNG plant will be about 6570 mil sm3 per year, at a conversion norm of 1,314 scm per tonne of LNG[51]. For a 20 year time horizon, the NG reserves required are about 132 BCM or 4.6TCF. These are large reserves: about 40% of the size initially estimated forKG D6.
LNG plants are located as close as possible to large sources of NG, in Qatar, Australia, Algeria, Russia, Indonesia, etc.

Liquefaction plants are highly expensive. The average global capital expenditure for liquefaction plants (excluding upstream and finance costs) was an average of $ 561/ton for projects completed between 2006 and 2010.[52]A 5 mil tpa LNG plant in this period would have cost about $ 2.8 billion. The same report indicates that the Capex for plants in subsequent periods would be twice as much, or about $ 5.5 billion, as seen in the chart below.
About 9% of the input NG is consumed in the process of liquefaction. [53]

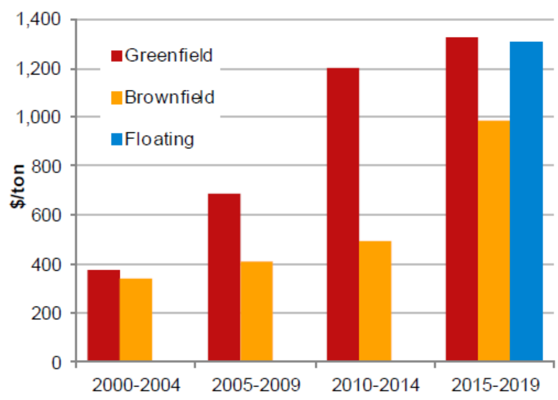


Figure 4.10: Average Liquefaction Unit Costs in $/ton (real), 1995-2019

Note: Only includes for existing and under construction projects.
Source: PFC Energy Global LNG Service

Chart 7 Average Liquefaction Capex per ton 2000 to 2019

The ships used to transport LNG must maintain the low temperature of (-) 162 deg C, which puts limitations on their size, and increases their operating cost. Most ships can carry about

135,000 cubic metres of LNG, while newer ships are larger at about 165,000 cu.m. They are also expensive: about $ 200 to 300 million apiece[54].

The 135,000 cubic metres of LNG carried by a typical carrier will expand 600 times on re-gasification to become 81 mil sm3 of NG. At full capacity, a 5 mil tpa Liquefaction terminal will send out 6,570 mil sm3 every year, as explained above. Thus, about 81 Shiploads have to be sent out every year.

If one ship can take 12 loads per year, then 7 ships will be needed, requiring an investment of around $ 1.750 billion. If the shipping distance is larger, then number of loads a ship may average in a year will be less; the investment will be proportionately higher.

The Regasification terminal with the LNG importer must have equally large receiving tanks to store the cryogenic cargo. LNG can then be warmed up ("Re-gasified") to change its physical state back to gas (to get R-LNG), which is then pumped through pipelines to local customers. The LNG receiving terminal being set up by Petronet LNG Ltd.at Kochi costs about Rs 4,600 crores for a capacity of 2.5 million tonnes per annum. This would be about $ 1 billion; extrapolating for a 5 mil tpa plant, it would be about $ 2 billion, considering recent changes in rupee value.

The cost of re-gasification presently charged by Petronet LNG is Rs 35 or $0.65/mmbtu on Gross Calorific Value; it increases 5% every year. Import duty at 5.15% is also payable on the CIF value of LNG, plus port charges etc.

Finally, a suitable Pipeline infrastructure is needed to evacuate the NG. The annual throughput of 6,570 mil sm3 mentioned above corresponds to a daily throughput of 18 mil mmscmd. Assuming that adequate customers to absorb this volume of gas are located at average 500 kms distance from the Regasification terminal, the pipeline infrastructure will cost about Rs 2,500 crores, applying a thumb rule of Rs 5 crores / km. If customers are further away, the costs will increase.

The total cost of the entire LNG chain for the example of a 5 mil tpa LNG plant works out to be:

Liquefaction:	$ 5.5 billion
Shipping	$ 1.75 billion
Re-gasification	$ 2.0 billion
Pipeline	$ 0.4 billion
Total	$ 9.65 billion

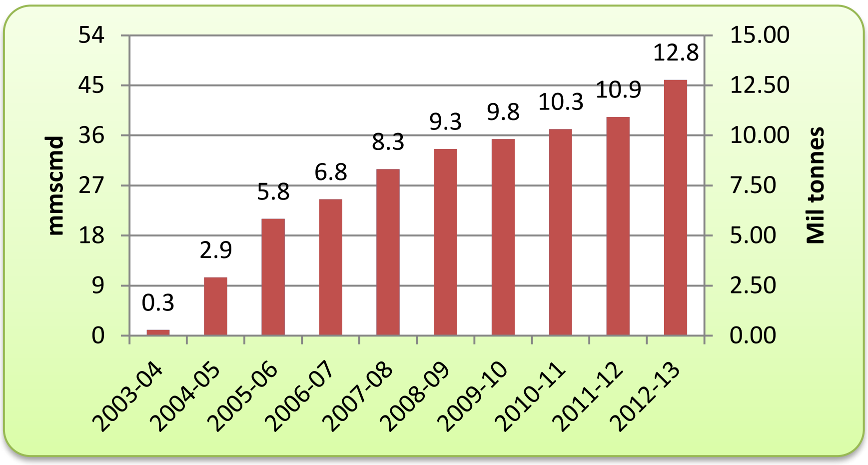
The large investments in each step of the chain causes the contracts to involve stiff penalties for non performance by any member of the chain. It is also very expensive to operate. Obviously, the final customer foots the total bill!

LNG import facilities in India

There are presently only two terminals operating regularly for imports for past several years:
- Petronet LNG Ltd, Dahej, and
- Hazira LNG Pvt Ltd, at Hazira.

Imports started in 2003-04, at Dahej. In the period shown, only Dahej and Hajira terminals were operative.

Table 30 LNG imports by India from 2003-04



These two terminals are well connected to the gas pipeline network set up by Gail and Gujarat State Petronet, on which there are several fertiliser, power, petrochemical and other large consumers:

- Hajira Bijaipur Jagdishpur, HBJ, line goes through Gujarat, Madhya Pradesh, Rajasthan and UP.
- Dahej Uran line DUPL via Hajira, goes to Maharashtra
- Dahej Vijaipur line DVPL

All the customers on these lines were set up on the basis of allocations of domestic gas; they supplement the shortfall in domestic supplies with LNG.

Two more terminals have been recently commissioned:

- PLL Kochi, at Kochi, and
- Ratnagiri Gas and Power Ltd, at Dabhol.

A very small quantity was imported at Dabhol for the first time in 2012-13. Kochi was commissioned this year, in 2013-14.

LNG Projected Import Capacity

Several more terminals are planned.[55]

Table 31 LNG Terminals Proposed in India

Companies	Location	Capacity	Year
BPCL	Mangalore, Karnataka		2018-19
Indian Oil	Ennore, Tamil Nadu	5 MMTPA	2016
Indian Oil	Odisha	5 MMTPA	
Shell and Reliance ADAG	Andhra Pradesh	5 MMTPA	2014-15
PLL	Gangavaram, Andhra Pradesh	5 MMTPA	
APGDC	Kakinada, Andhra Pradesh	3.5 MMTPA	
GSPC	Mundra, Gujarat	5 MMTPA	
H Energy	Raigad, Maharashtra	8 MMTPA	
Swan Energy	Pipavav, Gujarat	3 MMTPA	

Assuming that not all the capacities proposed on the East and West Coast will come up, the projected R-LNG terminal capacity in India would be as follows.[56]

Table 32 Projected capacity of R-LNG terminals

LNGterminal	2013-14	2014-15	2015-16	2016-17	13thPlan (2017-18–2021-22)
Dahej	12.5	12.5	15	15	15
HLPLHazira	5.0	5.0	7.50	10	10
Dabhol	5	5	5	5	5
Kochi	5	5	5	5	10
Ennore	0	0	5	5	5
Mundra	0	0	5	5	10
EastCoast	-	-	-	5	15
WestCoast	-	-	-	5	10
TotalCapacity(MMTPA)	27.50	27.50	42.50	55	80
TotalCapacity(MMSCMD)	101	101	156	202	294

If all these proposals do get implemented, then the R-LNG capacity would double by 2017, triple by 2022.

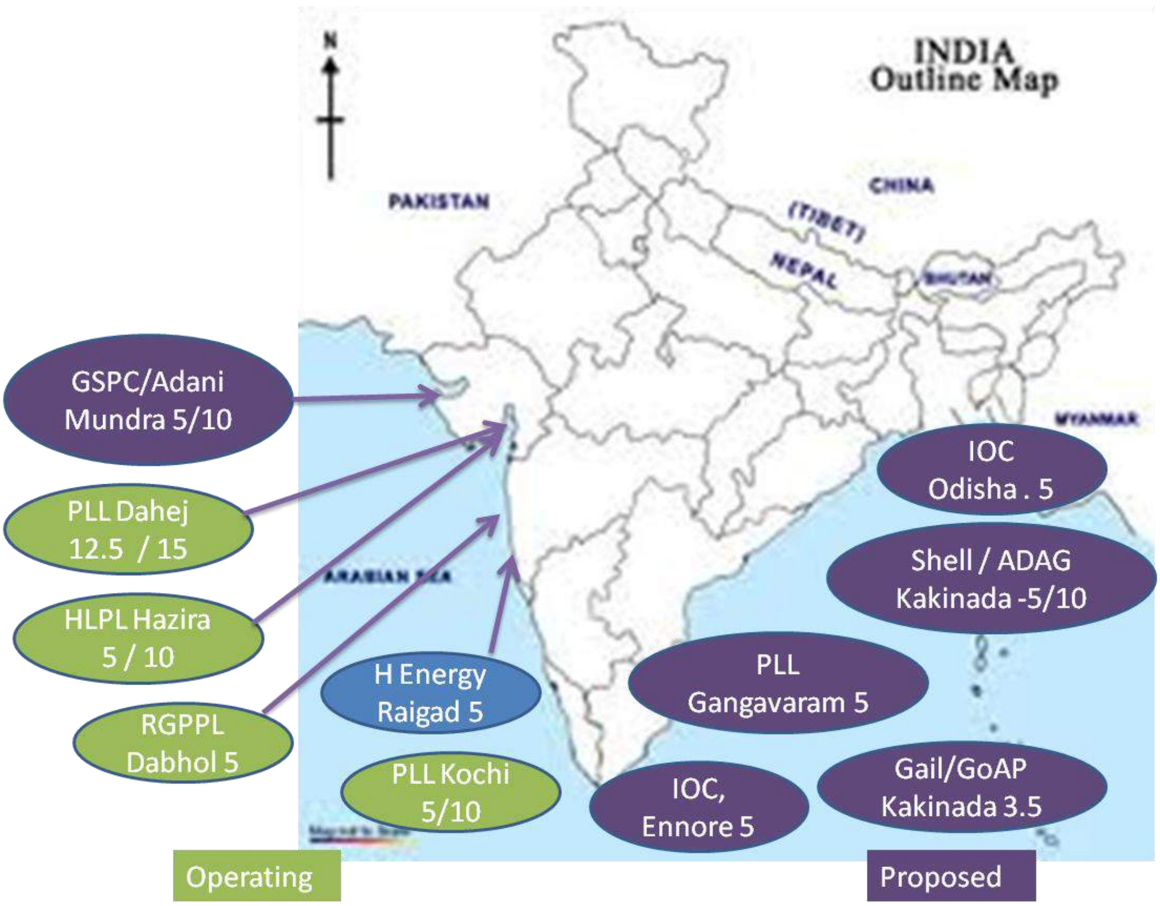


Figure 8 LNG Terminals – Existing and Proposed

Cost of LNG Imports

The landed cost of NG is estimated here for some long term contracts that will play a major role in determining the future of LNG in the country.

The Hajira terminal was set up by two multinationals, Shell and Total; as they have a strong presence in the global LNG market, they did not enter into long term contracts for either supply or sales. They operate on purchase of spot cargoes, and spot sales.

On the other hand, the Dahej terminal, which was set up by a consortium of public sector companies, entered into a long term 25 year supply contract with Ras Gas Qatar for 5 mil tonnes LNG from 2004 onwards, increasing in 2009 to 7.5 mil tonnes, which is about 28 mmscmd. As this had a Take or Pay clause, they also entered into long term contracts with buyers, with matching conditions. The contract set the FOB price in $/mmbtu GCV by a formula as [1.9/15 * JCC], where JCC is the average price of Japanese Custom Cleared crude oil for the previous 12 months. For the period 2004 to 2008, the value of JCC was capped at $ 20, which meant that the FOB price never exceeded $ 2.53/ mmbtu. For 2009 to 2013, a partial moving cap applies, in order to provide a smooth transition to a cap free situation from 01 January 2014, when the formulasimplifies to 12.67% of JCC price. The price changes every month.

According to a recent GoI report, PLL has signed another contract with Exxon-Mobil for import of
1.44 mil tpa of LNG from its Gorgon venture in Australia, which is scheduled to be commissioned at the beginning of 2015. The contract sets the monthly FOB price at 14.5% * JCC, where JCC is the import price 3 months earlier. [57]

The same report indicates that the freight cost from Qatar to Dahej for LNG being imported under long term contract since 2004 is estimated at $ 0.30 / mmbtu. For the LNG that will be imported from Australia for the Kochi terminal from 2014 onwards, the rate is reported to be $0.75/mmbtu.

The cost of re-gasified LNG ex-terminal is calculated below, for supplies from Dahej and Kochi.

Table 33 Cost build up of Re-gasified LNG for buyer in another state

	Item	Qatar LNG Dahej 2014	Australia LNG Kochi 2015
1	JCC oil price $/bbl	110	110
2	Formula linkage	12.67%	14.5%
3	FOB price$/mmbtu	13.94	15.95
4	Shipping cost$/mmbtu	0.3	0.75
5	Insurance$/mmbtu	0.0025	0.005
6	CIF cost$/mmbtu	14.24	16.71
7	Import duty $/mmbtu	0.73	0.86
8	Port charges $/mmbtu (assumed)	0.1	0.1
9	Landed$/mmbtu	15.07	17.67
10	FOB price at Rs 63/ USD	949.59	1112.91
11	Re-gas charge (5% inc p.a)	38.60	50.00
12	Gujarat Purchase Tax 4%	39.53	0.00

	Item	Qatar LNG Dahej 2014	Australia LNG Kochi 2015
13	Central Sales Tax 2%	20.55	23.26
14	Marketing Margin	10.70	11.30
15	Total Cost GCV Rs/mmbtu	1058.97	1197.47
16	Total Cost NCV - Add 10%Rs/mmbtu	1164.87	1317.22
17	Total Cost NCV - $/mmbtu	18.49	20.91

If the buyer is in the same state, then the Gujarat Purchase Tax and the CST will not apply; the local VAT will apply. Also, the above calculation does not include the transmission charge from the terminal upto the customers' premises, as that will vary from customer to customer.

It is seen that the minimum cost for an outside state buyer will be about $ 18.5/mmbtu for Qatar LNG in 2014, and about $ 20.9 for Australian LNG in 2015, if present JCC remains the same.

Use of R-LNG by Fertiliser and Power sectors

If R-LNG alone is to be used for making fertilisers, or for generating power, then the cost of the end product will be as follows:

a) Manufacture of Fertilisers: about 20 mmbtu of gas is required to make 1 tonne of Urea. Assuming that R-LNG is available at $ 20/mmbtu, then the cost of gas alone in Urea will be about $ 400/tonne. In addition, there will be other operating and capital related costs of the order of $ 150/tonne, taking the total cost to $ 550/tonne. This is much higher than the present import cost of about $ 300/tonne. Thus a Urea plant based on R-LNG alone will not be viable.

b) Generation of power: about 1800 kcals are required to generate one unit (kwh) of power. This is about 0.0071 mmbtu. The gas cost alone will be $ 20 * 0.0071 / kwh, i.e. $ 0.142/kwh. At an exchange rate of Rs 63/$, this works out to Rs 9/ kwh. This is only the fuel cost, and is much above that for coal based power. At this high value, an LNG based power plant is not likely to get enough demand, under the merit order dispatch rule, to be financially viable.

If R-LNG is to be used by these sectors, then it can only be as a small supplement to the domestic gas presently available in the band $ 4 - 8 / mmbtu.

Operational issues for new LNG terminals

In order to be successful, all new terminals need to fulfil four conditions:

- sign up with enough customers to off-take all the R-LNG that they bring.
- ensure adequate pipeline connectivity to deliver the R-LNG to their customers.
- offer R-LNG at rates that are affordable.
- Sell enough R-LNG to be financially healthy.

The Dabhol terminal, owned by Ratnagiri Gas and Power Private Ltd (RGPPL), is able to operate only under fair weather conditions, as a break wall has to be completed in the sea to protect the harbour from the rough seas that prevail during the monsoon period. This will be ready by 2014.

Even though the Dabhol terminal was set up as part of the original Enron plant with the intention of using the LNG for generating power, the present view is that the LNG will not be used for power generation. Instead, the LNG will be sent through a pipeline from Dabhol toBengaluru. The line is being laid at cost of about Rs 4,600 crores over a distance of about 1,000 kms and with carrying capacity of 18 mmscmd. It will supply gas to customers in the cities of Ratnagiri and Kolhapur in Maharashtra, and Belgaum, Dharwad, Haveri, Davanagere, Chitradurga, Tumkur and Bengaluru in Karnataka. To run the power plant, the GoI allotted 7.8 mmscmd of gas from KG D6. However, following the decline in output, the gas flow has stoppednow, and so has the power plant.

The Kochi terminal has presently few customers, due to limitations on the pipeline evacuation capacity, and due to high price of LNG. The 2.5 mil tpa terminal cost Rs 4,600 crs. It has an LNG import contract with Gorgon, Australia for 1.5 mil tpa for 20 years from 2016 ?, with FOB GCV price at 14.5% * JCC. The anchor customer was to be NTPC's second power plant 50 kms away at Kayamkulam, but the ex-terminal cost of about $ 21 / mmbtu NCVstymied the idea. In the absence of bulk customers like Urea and power, the sales must be to city gas units, for piped gas (as substitute for LPG), CNG (for transport), and industrial / commercial uses.

It is presently supplying to nearby industries like Fertilisers and Chemicals Travancore, Nitta Gelatine and BPCL refinery. Since the fertiliser plant FACT was using Naphtha, its substitution by gas / R-LNG was mandated by GoI, under the Urea subsidy scheme. For the same reason, a pipeline is under construction from Kochi to Mangalore, in order to supply about 1 mmscmd R-LNG to Mangalore Chemicals and Fertilisers Ltd. at Mangalore. Another pipeline is under construction from Kochi to Bengaluru. Both pipelines will also supply gas to in between towns for domestic / transportation / industrial / commercial uses.

The pipeline to Bengalurutraverses large sections of Tamil Nadu, whose government has sought re-routing of the line, in order to avoid farm land. This has held up work. To be useful, a pipeline has to be 100.00% complete, as even a one metre gap makes the entire line un-usable.

It may be noted that city gas is not a bulk consumer of gas: a large city like Mumbai used 2 mmscmd in 2012-13, after 10 years of MGL operations.Thus, in order to fully consume the 9 mmscmd from Kochi, City Gas Distribution networks have to be set up in about, say 15 small cities. The process of CGD is regulated by the Petroleum and Natural Gas Regulatory Board which is authorised to determine locations for setting up CGD, inviting bids, and authorising entities to set up CGD networks. This is a lengthy process.

In order to make R-LNG more acceptableto customers, PLL has been urged to re-negotiate the price with the Australian suppliers.

Thus, the Kochi terminal is expected to have a slow ramp up to full capacity utilisation. It will be a case study for other investors in LNG terminals.

Import contracts India

In addition to the two contracts discussed above by PLL, several contracts have been entered into by GAIL:

- Short /medium term contracts with Marubeni of Japan, GDF Suez of France and GNF of Spain for a combined 1.36 MMTPA of gas.
- Long term contracts, for about 20 years:
    - 5.8 MMTPA from Cheniere and Dominion of the USA, and
    - 2.5 MMTPA from Gazprom of Russia

All contracts have strict Take or Pay clauses, meaning thatPLL / Gail must offtake the contracted quantities within the timelines agreed upon in the contract, otherwise they have to pay the full value to the suppliers. It is essential for Gail to get long term customers for all the quantities they have contracted, so as to avoid heavy penalties. As an example, the lifetime value of the Gorgon contract is estimated at $ 20 billion over 20 years.

Global LNG scenario[58]

In 2012, the global trade in LNG was 240 MT, of which India's share was just 12 - 13 MTs, or 5%.

As much as 70% of the global trade was under contract, with the balance on spot basis. Indian trade was on similar lines.

There are about 362 LNG carriers available globally to transport LNG.

As of the end of 2012, global Liquefaction capacity was 281 Mil Tonnes, whereas Regasification capacity was more than double at 642 Mil Tonnes. Thus, demand as represented by Regasification capacity was far higher than the Supplyas represented by Liquefaction capacity.

In another 5 years, that is by 2017, it is estimated that Liquefaction capacity will rise to 366 MTPA whereas Re-gasification capacity will rise to 750 MTPA. Thus, demand will continue to run far ahead of supply.

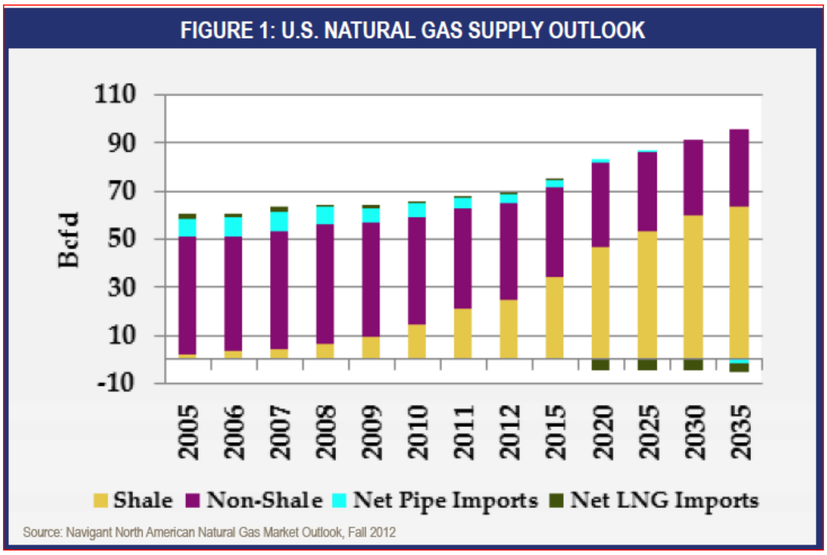
Almost all the new capacity will come on-stream in 2016-17, when many of the Australian and Papua New Guinea projects now under construction, and the first of the US projects, come on-stream.

In the next two years, significant amount of Liquefaction capacity will come on stream in Australia, which will ease the supply situation. Shortly thereafter, about 75 mil tpa Liquefaction capacity is expected to come up in North America, that is USA and Canada.

Impact of US Shale revolution on LNG pricing

The US shale revolution is having long lasting and worldwide impact on both crude oil and Natural Gas markets.
The chart below shows clearly how Non-shale gas production is forecast to reduce in the period 2005 to 2035, and how Shale gas output is expected to increase in the same period.[59]Shale gas production has risen from a small level of 2 BCF/d level in 2005 to 26 BCF/d in 2013. As a result, shale gas accounts for about 40% of the total gas production of 65 BCF/d in 2013.[60]

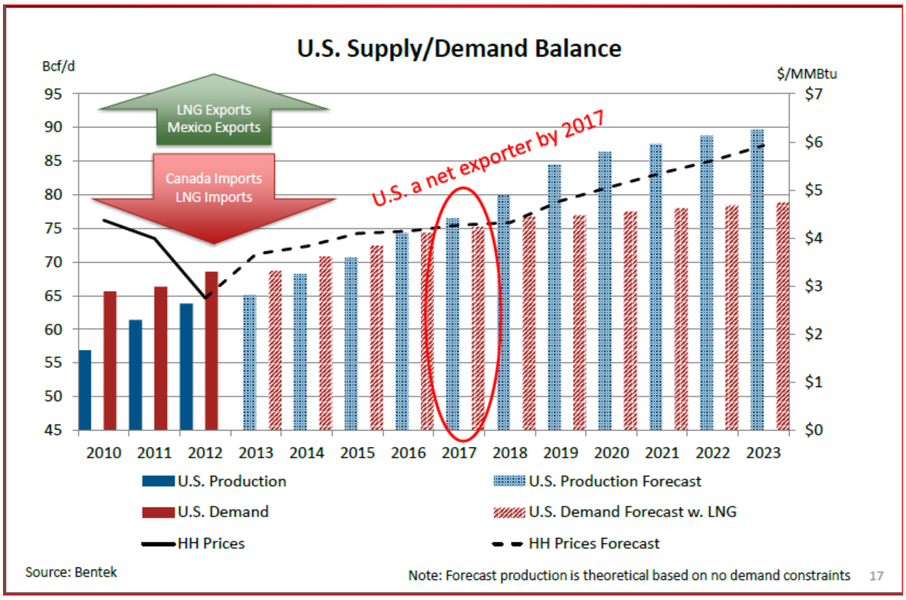
Table 34 US Natural Gas supply outlook, by source, to 2035



As the production of shale gas continues to rise to over 60 BCF/d by 2035, the pipeline imports from Canada will decline and stop. Further, the negative bars after 2015 indicate that exports of gas will commence.

The following chart illustrates the views of Bentek Energy that the production of domestic gas will exceed demand by 2017, which will enable exports to take place.[61]

Table 35 US Supply/ Demand balance for Natural Gas



The great significance of this is that, prior to the development of technology for extracting gas and oil from shale sands, the USA was expected to become a major importer of Natural Gas, since its output of non shale gas is forecast to drop from a level of about 50 BCF/d in 2005 to about 25 in 2035, as shown in

Table 34 US Natural Gas supply outlook, by source, to 2035. In anticipation of the USA becoming a major importer of gas, the state of Qatar had invested heavily in setting up the world's largest LNG facilities totalling 77 mil tonnes per annum, which is about 10 BCF/d.The Shale gas revolution will make North America as big an exporter of LNG as Qatar, who is now compelled to actively seek alternate outlets for its LNG.

LNG Cost Build up

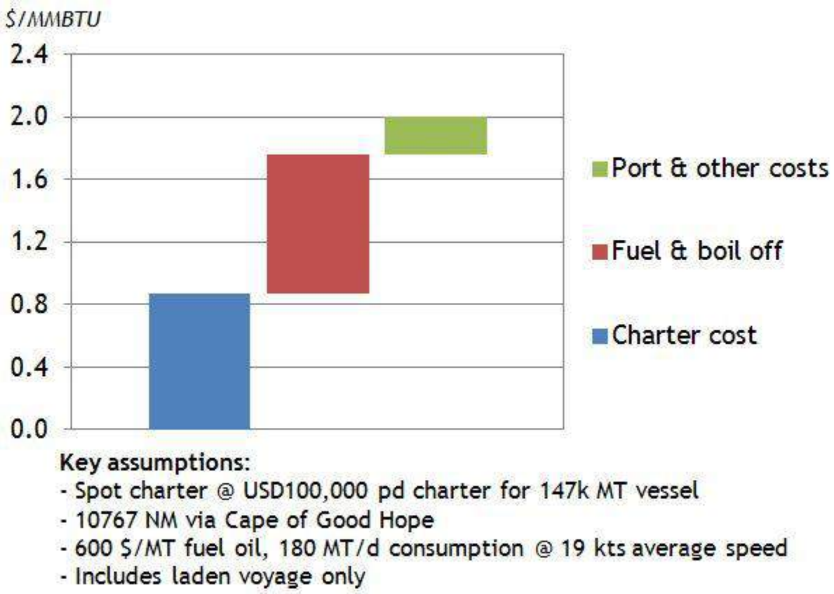
An estimate of how the costs build up for an export cargo of LNG is given below:

Table 36 Cost Build up for LNG being exported

	USA	Australia
Adapted from Oct 2013 paper[62]		
Base cost	3.5	4.5
Local transmission upto Liquefaction plant	0.5	0.5
Liquefaction cost	3.0	3.5
Shipping cost to Japan	3.2	1.5
Breakeven FOB cost to Japan DES 2018	10.2	10

The following table illustrates how the shipping cost itself gets built up, for transport of a cargo from Nigeria to Japan, via the Cape of Good Hope.

Table 37 LNG – components of shipping cost



Crude Oil Price developments

In crude oil too, developments in the USA are changing the global scenario on lines similar to that described for Natural Gas.

The following chart shows that crude oil consumption has reduced from the peak of 20 + mil barrels/day in 2005 – 2007, and is showing a slow declining trend. On the other hand, production is moving upward, with the result that imports have been steadily declining (blue line) to about 11 mil barrels/day[63].

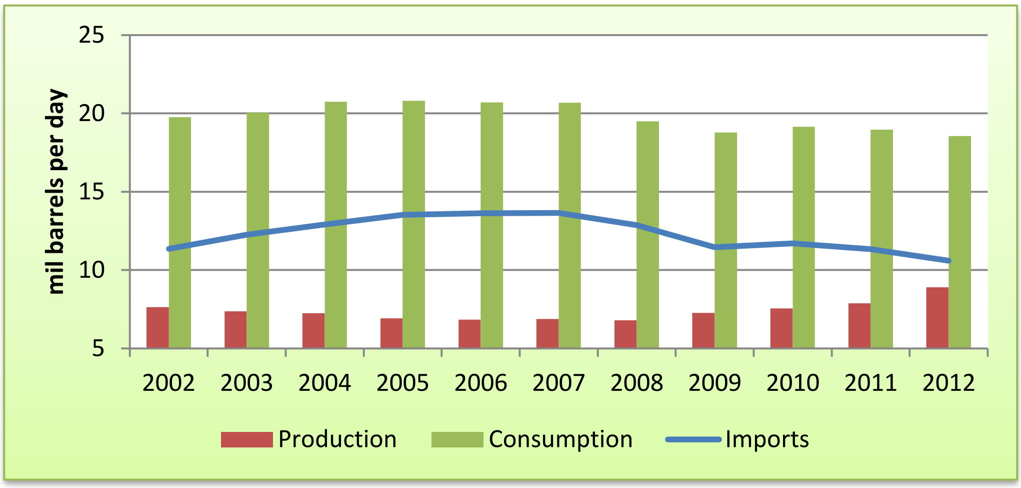


Chart 8 USA Crude oil data

In addition to a lot of shale oil being produced, large discoveries of oil in the Gulf of Mexico are expected to enable US oil production to almost double from 5.5 in 2010 to 10.5 mil barrels/day by 2019. If consumption remains at the levels seen in recent years, the higher production will enable USA to reduce imports to around half the present levels. In the chart below, Bentek Energy indicates that Brent oil prices may slide from present $110 / barrel to the $ 90 level by 2019[64].

This augurs well for LNG users in India, whose purchase prices are linked to JCC.

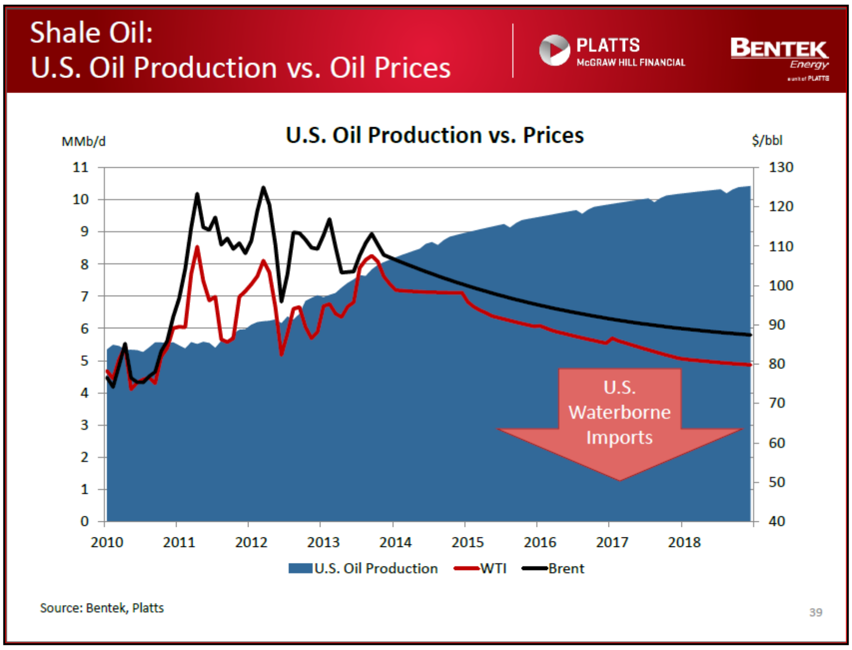


Chart 9 US oil production vs crude oil prices

Scope for reduction in FOB price of LNG

According to the PSC Report[65], the "average price of liquefaction costs with older plants is of the order of $ 2.5/mmbtu3. For plants which started deliveries in 2010 or after, the liquefaction cost is of the order of $ 3.5 to 4.0/mmbtu. A recent contract signed by GAIL with the Sabine Pass facility in United States of America for supplies to commence in the year 2016 from a brownfield project is around $ 3.0/mmbtu."

By adding the known gas prices to liquefaction costs, a rough idea of the FOB price can be obtained:

Table 38 LNG – build up for FOB cost

In $/mmbtu	Qatar	Australia	USA
Gas cost	1 – 2	5.4 [66]	4
Liquefaction costs	2.5	3.5 – 4	3
Others	0.5	0.5	0.5
Total	4 – 5	9.4 – 9.9	7.5
Actual/ proposed FOB	13.94	15.95	–
Scope for Reduction	9 – 10	6.5 – 8	–

LNG suppliers contend that their product competes in many places with crude oil derivatives. Crude oil is sold at around $ 100 / barrel, which is also much above the cost of production in the Middle East. As gas and oil are extracted in a similar manner, the sellers seek price parity between gas and oil. A barrel of crude oil contains roughly about 6 mmbtu. So, one mmbtu of energy should cost 1/6 of the cost of a barrel, which works out to 16.67%. Thus, sellers argue that a formula of 12.67% of JCC (Qatar contract) or 14.5% of JCC (Australia contract) provides a significant discount to crude oil.

In this context, it is a welcome development that the forecast for crude oil prices is for a reduction to $ 90 in next few years, from present levels of $ 110/ barrel.

LNG Price Trends

More than 50% of global LNG is imported by Japan and South Korea, who have no energy resources. They were earlier importing fuel oil for generating power, and have substituted it by LNG now. So, it was logical to price LNG with reference to the crude / fuel oil being displaced. This practice has then been extended to other importers, such as India and China.

In case of India, the largest use of gas is for generating power. But India already has a huge power generation industry based on coal, because of our large coal resources. Thus, Indian buyers want LNG price to be on parity with domestic coal.

Clearly, there is a huge disconnect between Indian expectations and the global situation.

Fortunately, there is also concern in Japan that energy prices should be reduced. Having closed nuclear power plants, Japan has stepped up its LNG imports, which led to price increases. The average price for 2012 was over $ 16 / mmbtu. These were being passed on to domestic consumers, who have started to protest. The Energy Ministry has now decided that "utilities ... will not be able to pass costs on to electricity customers beyond a new ceiling..." While a final decision is awaited, it is anticipated that it may be around $ 13 / mmbtu in another year or so.[67]

Both Japan and South Korea have started promoting competition between LNG suppliers to reduce prices, and end the 'Asian premium'. A study by Bentek Energy shows that the Breakeven cost of LNG delivered ex ship to Japan 2018 from various sources could be:

Table 39 LNG Delivered cost to Japan

	LNG Source	$/mmbtu DES Japan 2018
1	Canada West Coast	9.35
2	USA East Coast	10.18
3	Australia	9.94
4	Papua New Guinea	7.03
5	Indonesia	7.60

Clearly, a lot of LNG can reach Japan at a price around $10/mmbtu. This is much less than the India cif prices of $ 14 and $ 16.5 seen in the calculation above for LNG from Qatar and Australia. Just like the Japanese are doing, there is an attempt by Gail / PLL to re-negotiate the price with the Australia consortium.

The strong competitionfor existing LNG suppliers, has already led them to accept the need to reduce prices.New contracts are hybrid – part linked to Hub gas prices, part to oil. The ratio to crude oil, called "slope",has dropped in some cases to 12%.

A major constraint today for transporting US LNG from the Gulf of Mexico is that the Panama canal is not wide enough for LNG ships. The project to widen the canal is likely to be completed by 2015, after which most LNG vessels will be able to use it. The shipping distance from the US GoM to Japan will drop from 16,000 to 9,000 miles which will increase their competitiveness vis–a-vis Australian LNG exports.

Pipeline network

The maximum length of NG pipelines have been laid by GAIL India Ltd, which was set up by GoI for the purpose of developing a gas transmission and marketing business.It operates themajor gas pipelines in India: the 1,740-mile Hazira-Vijaipur-Jagdishpur, (HVJ), line runningfrom Gujarat to Delhi, and the 480-mile Dahej-Vijaipur, (DVPL), line.

Map of Pipeline Network in India

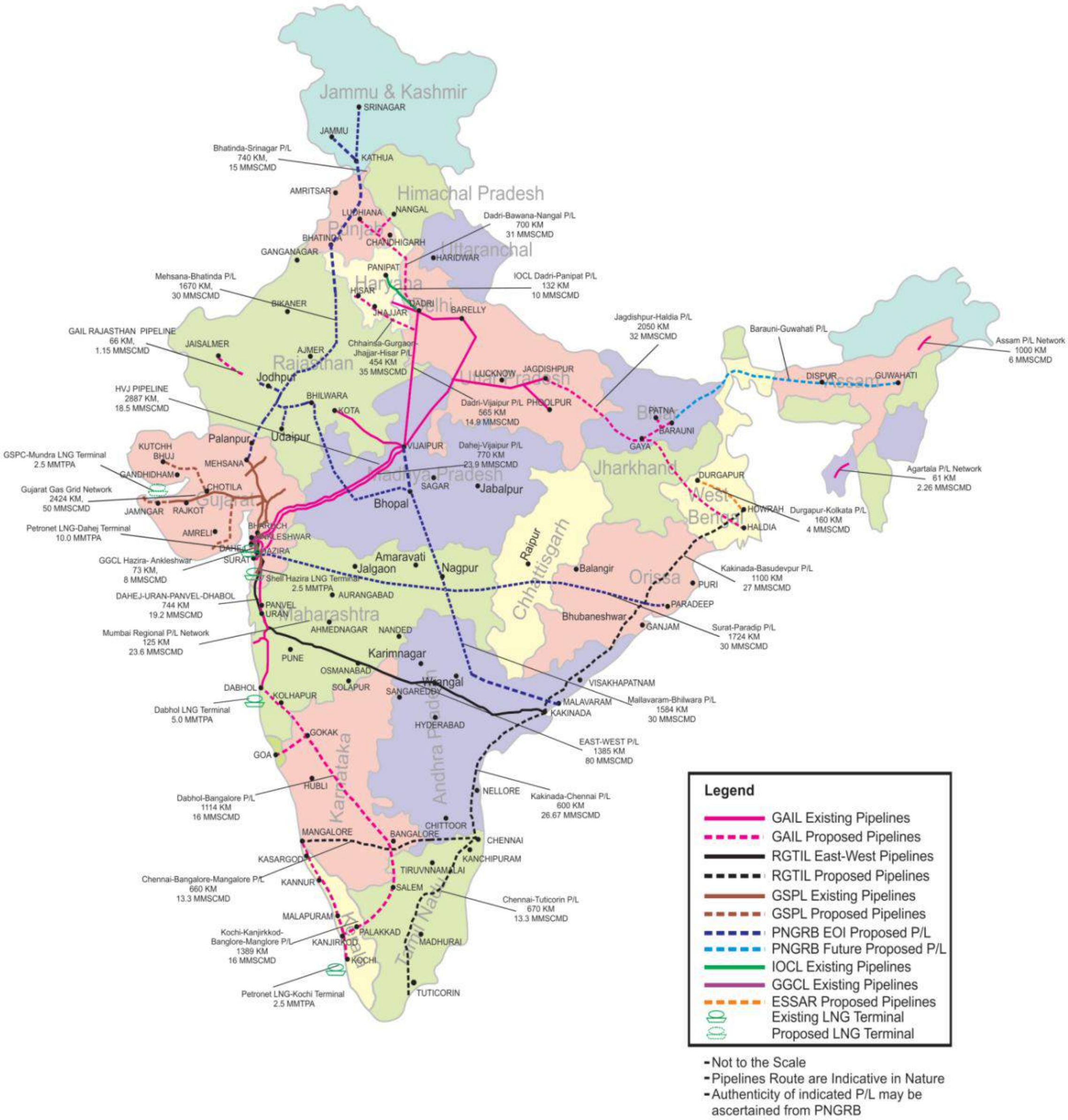


Figure 9 Gas Pipeline network in India

East – West pipeline of RGTIL

RIL promoted another company, Reliance Gas Transmission and Infrastructure Ltd., to construct this pipeline to transport upto 120 mmscmd of KG D6 gas from Kakinada to Bharuch. It was commissioned in April 2009. It cost Rs 17,900 crores for length of 1,375 kms, i.e. about Rs 13 crores per km; on a per km per mmscmd basis, the cost works out to about Rs 10.8 lakhs.

The transmission tariff was set on the basis of 80 mmscmd throughput expected from the KG D6 field at that time. At peak, it carried 60 mmscmd of gas for a few months. It now carries less than about 15 mmscmd of gas, due to problem of limited gas quantity available from KG D6. Since supplies have been reduced by the gas supplier, they cannot invoke "Take or Pay" conditions. The pipeline business is clearly in a difficult financial situation.

Many pipelines are not being pursued as enough gas / LNG / Customers not available.

Pipeline issues

In case there are enough customers at the prices on offer, then the NG will have to be sent through pipeline to them. But, pipelines are expensive, and can cost about Rs 5 - 15 crores / km, depending on capacity, terrain, total length, etc. Further, the transmission tariff for pipelines is set by the Petroleum and Natural Gas Regulatory Board on the basis of a minimum economic life of 25 years. Thus, they have to be of certain minimum size for purposes of viability, and must be assured of regular business on long term basis, in order for the investment in a pipeline to be an economic proposition.

This is a typical "chicken-and-egg" question: potential customers will not commit to buy NG in the absence of pipeline, whereas gas transmission companies will not invest in pipelines until they have enough customers. The only way to resolve this dilemma is for both customers and transmission companies to have detailed discussions on the business models of each other, to develop the required facilities in coordination and synchronisation. This will reduce the risks for both.

Many pipelines were proposed, but few are active since the availability of gas at the right price is a major question mark.

Gas transmission companies seek to reduce their risk by requiring customers to agree to bear standing charges for the pipeline upto their premises. These standing charges are payable on a monthly basis, whether or not any NG actually flows through the line. The charge typically takes care of the capital related expenses incurred on laying the line upto the customer's premises from a trunk pipeline owned by the gas transmission company. In those cases, where such fixed monthly charges are not levied, another condition of minimum drawal quantity is placed. Here, the customer agrees to pay transmission charges for minimum daily quantity even if lesser quantity of NG is drawn. In addition, there are onerous penalties for drawing higher quantities than contracted.

Further, gas marketing companies want to ensure the continuity of sales by requiring customers to accept "Take or Pay" conditions in the Gas Sales and Purchase Agreements (GSPA). This means that customers agree to pay for a minimum daily quantity of NG even if they do not purchase it. This is a condition that can be accepted only by those customers who have assured sales of their downstream products and sufficient margins to absorb the delivered price of NG.

Pipeline construction must run the gamut of issues such as:

- route selection
- Land acquisition / Right of Use
- natural hurdles - rivers, mountains, roads, etc.
- population density
- approvals for traversing farm land / forest land / reserved land etc.
- safety precautions as NG is inflammable.

These issues have impinged on the growth of the pipeline network in India.

Overseas Pipeline supplies

India has entered into negotiations with gas rich countries in its neighbourhood for obtaining NG.
There are three such proposals, of which two are for on-land lines, and one for an underwater line in the sea.

An Iran - Pakistan - India (IPI), pipeline has been under discussion for several years; so has a Turkmenistan - Afghanistan - Pakistan - India (TAPI), pipeline.

A political row with Iran has prevented the IPI line from moving forward, though the Iran Pakistan part may go forward.

In case of TAPI, the participating countries (Turkmenistan, Afghanistan, Pakistan and India), signed a framework agreement in 2010, and agreed on unified transit tariffs for the route in early 2012. In May 2012, GAIL has executed a Gas Sales Agreement (GSA), with TurkmenGaz of Turkmenistan for importing asizeable 38 mmscmd of gas through the (TAPI) pipeline for a 30 year period. In early February 2013, India's government approved a special purpose legal entity to which participating members of the pipeline would contribute investment funds. The Asian Development Bank has been appointed as a Transaction Advisor in mid 2013.

However, neither pipeline may be expected to be realised in next decade or so, considering the geo-political issues that bedevil the region.

SAGE: Underwater deep sea pipeline Oman to India: estimated length 1150 kms with 31 mmscmd capacity of NG, at an investment of $ 3 billion. The estimated transmission tariff was $ 1.8 / mmbtu. Proposal is pending since 2008.

International Scenario

Global Gas Price scenario

The complications of transportation prevent the development of a single global price for Natural Gas. It cannot be easily transported from a region of low price to a region of high price, so as to even out the prices.

The annual energy review published by BP for 2012 provides data on prices at important regions of the world[68]. The trend of prices since 2000 in the chart below shows that the prices were in a small band during the period 2000 to 2005, but have thereafter diverged. The price at which Japan imports LNG closely follows crude oil prices. Gas prices in Germany and UK also follow the directional trend of crude, but absolute prices are much lower. Only in USA and Canada have gas prices dipped after 2010, and have moved in opposite direction to other gas prices.

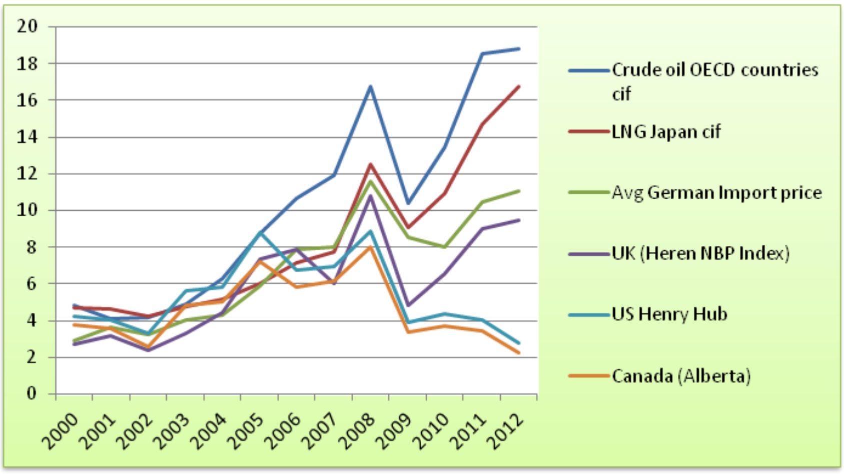


Chart 10 Price trend crude oil, LNG and Gas at major regions

The International Gas Union has compared prices of NG across the world.[69] The prices inthe Asia Pacific regionare seen to be high because the highest rates of $ 15.5 to 16.5 / mmbtu are seen in Japan, Singapore, Taiwan and South Korea, who are dependent on LNG; further, their imports exceed 60% of total LNG trade.

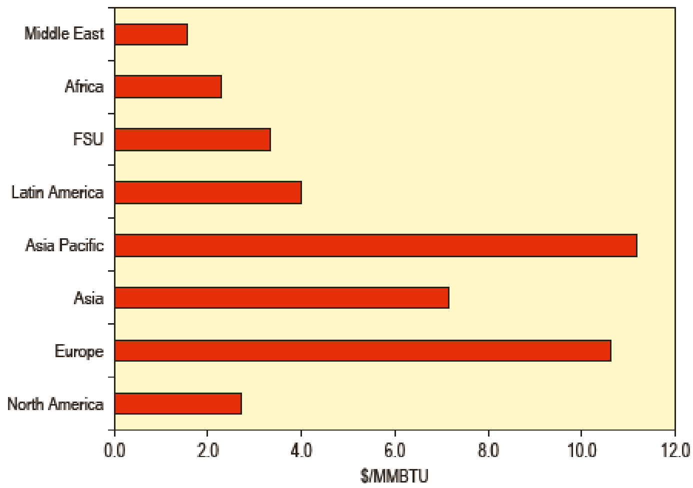


Chart 11International Wholesale Gas Prices 2012

Another chart in the document provides some indication of the rates by country.[70]These read as follows:

- China above $ 8/ mmbtu,
- India above $ 6,
- Indonesia $ 5,
- Australia $ 4.5,
- Trinidad $ 3.5,
- USA $ 3,
- Nigeria $ 1.5,
- Qatar / Oman / Saudi Arabia $ 1,
- Algeria $ 0.5.

It will be observed that the countries after India are exporters of LNG, or will soon be. It is recommended that these numbers should be considered for working out the netback to LNG exporters in the new price formula to be applied for domestic gas in India under the New Pricing Guidelines.

International Gas Trade

Export of NG occurs by two means:

- As NG by pipeline over land, and
- As LNG by ship, over sea.

In 2012, Pipeline exports were 706 BCM, and LNG 328, totalling 1,034 BCM.

The maximum pipeline imports occurred in Europe at 377 BCM, followed by North America 129 BCM.
The largest exporters by pipeline are the Russian Federation at 186 BCM, followed by Norway 107 BCM, and Canada 84 BCM.

In LNG, the largest importers are Japan 119, S Korea 50, Spain 22, India 21, China 20, Taiwan 17 BCM.

Power Sector

Gas based power plants had received a firm allocation of 31.2 mmscmd gas from KG D6, which has been completely stopped from early this year.

At present, there are many companies who had invested in power and other sectors after they received allocations of KG D6 gas, but after supplies were curtailed are now either not operational or operating at lower levels or with expensive alternates. Gas-based generation has been in decline for the past two years: in 2011-12, generation declined by 6.8 per cent, whereas in 2012-13 it was down by 28.5 per cent. The average plant load factor (PLF), of gas-based power stations came down to 22 per cent in the September 2013 quarter, from around 41 per cent in the corresponding quarter a year ago.

Many are in financial difficulties, such as RGPPL and many power generation companies; steel and petrochemical units have also been hit badly. In some cases, they are unable to service their borrowings, and have turned into NPAs. Clearly, such a situation should not be allowed to repeat.

Table 40 Gas Supply status to Power sector 2013

	Capacity	Gas Requirement at 85% PLF	Gas Supplies in March 2013	Unmet Demand
Operationalunits	MW	MMSCMD	MMSCMD	MMSCMD
CentralSector	6616	30.2	11.0	19.2
StateSector	4920	24.1	10.2	14.0
PrivateSector	7294	33.0	7.5	25.5
Overall	18830	87.3	28.6	58.6
CommissionedcapacitywithNoGassupply	2568	11.7	-	11.7
Capacityunderadvancedstageofcommissioning	3355	15.3	-	15.3
Total	24753	113.3	-	84.7

Domestic Gas allocation policy:

The policy has evolved over the past several decades as domestic gas became available.

Exploration for oil started in the early part of last century. After independence, the Oil and Natural Gas Commission was established with the mandate to undertake Exploration and Production in India. Another public sector agency was Oil India Limited, ("OIL"), whose activities were in North East India. At that time, Government of India ("GoI"), allotted certain fields to ONGC and OIL for this purpose. These are called Nominated fields. Initially, GoI had no buyers for the NG produced from these fields (including Bombay High), and it used to be flared. However, a few courageous entrepreneurs ventured into the business of buying the NG for use in various industrial activities, such as making petrochemicals, fertilisers, power, steel, glass, etc. The NG produced from Nominated fields of ONGC & OIL was sold to them at a price determined according to the Administered Pricing Methodology, for which reason it is described as APM gas.GoI allotted the NG to customers as per the then prevailing policies. These contracts cannot be changed.

In 2005, GoI distinguished between use of APM gas for core and non-core sectors, by differential pricing:

- Power and fertilisers were considered as Core sectors; the price applicable to them was raised to $ 4.2/mmbtu
- For all othersectors, the price was raised to $ 4.75/mmbtu, which was raised a few years later further to $ 5.25/mmbtu. These Non-core sectors included refineries, petrochemicals, steel, etc. These are usually referred to as "non-APM" sectors.

The quantum of domestic gas going for core sector applications was estimated at 50 mmscmd in early 2013, and for non-core at 23 mmscmd.

Domestic Gas supplied from Pre-NELP fields was allocated to consumers as per the then prevailing policies. Selling prices were settled as per the contractual arrangements made at that point of time. The largest such allocation was for the Panna -Mukta -Tapti field in the Western Offshore Region. This field is operated by a consortium consisting of ONGC 40%, BG 30% and RIL 30%; the operator is BG. Output rose to about 17 mmscmd in 2006 or so, but has now declined to less than half.

The first major production of Natural Gas has come from the KG D6 field, which is operated by a consortium consisting ofRIL 60%, BP 30% and Niko Resources 10%; the operator is RIL. This field was allocated under NELP 1. It became clear in 2007 that the output from this field would be significant. Demand for gas had also risen significantly in the country at that time. Hence, GoI invoked some provisions in the contract that authorised them to allocate the output in terms of a gas policy framed by GoI. An Empowered Group of Ministers was formed that decided that Gas from this field would be allocated as per the following order of priority:[71]

1. Fertilisers
2. LPG
3. Power
4. City Gas, for household and transport sectors
5. Refineries, sponge iron, petrochemicals, etc.
6. New power plants

It is important to note that new power plants were given very low priority. The main reason was due to the fact that there were many existing gas based plants that were short of gas. Another important reason was that the Field Development Plan for KG D6 showed that the production profile showed a ramp up period of about 3 years when output would rise to a peak level of about 80 mmscmd, followed by a plateau period of about 7 years, and lastly a decline phase of 3 years which would exhaust the field. Thus, if any new power plant were to be set up to be run exclusively on KG D6 gas, it would compulsorily have to search for alternate sources of gas after 7 years or so.

It may be noted that the business group that had announced the most ambitious plans for gas based power plants, namely ADAG, did not invest in this area after the priority policy was formulated; however, others did, even though they had no allocation of gas, and are now seeking relief.

The unexpected reduction in output from KG D6 has converted the euphoria of 2007/ 2008/ 2009 into gloom. Many power plants and some steel plants (Welspun Max and Ispat industries at Uran), are in dire financial straits.

The key lessons to be learnt from the above are that:

– investments should be planned only after careful understanding of the Production Profiles and Field Development Plans of the gas fields from where gas is being sourced;
– the total allocation of gas should maintain some cushion for under-performance of the field, that is lower output, and delayed output.

In mid 2013, the GoI decided that the allocation of domestic gas to the fertiliser sector should be capped at 31.5 mmscmd till 2015-16; any additional gas output that may become available till then will be given to the power sector, in view of the stoppage of supplies from KG D6. Further, the situation would be reviewed in 2015-16, to determine the future gas allocation policy, depending on the then estimates of domestic gas production and availability.

Estimate of gas required for fertiliser sector based on future expansions

According to the Fertiliser Association of India, the Fertiliser sector received,in March 2013, 44 mmscmd gas, of which 11 was LNG (contract + spot).Following conversion of all Naphtha and Fuel Oil based urea plants to gas, plus some de-bottlenecking, present Fertiliser plants require about 57 mmscmd of gas. This includes all Urea plants, and Ammonia based fertiliser plants.[72]

Though the country produces about 22 mil tpa of Urea, it is still short of requirements by 8 mil tpa. About 25% of urea requirements are imported. This shortfall will increase as food demand is continually rising.
Considering this future requirement, the FAI had proposed that an additional 20 mmscmd will be required for 10 new Urea plants, of which 4 are expected by 2017, and the balance in due course. Thus, the total future requirement is estimated at 77 mmscmd.

However, the supply of NG to fertiliser sector has been capped at 31.5 mmscmd till 2015-16; any additional gas output will be given to power sector.The GoI will review the situation in 2015-16, as additional gas may be available.

NG for power sector in Indiain future

There is no doubt that the power sector is currently reeling under severe shortage of NG. It is also clear that fertilisers will always get priority over power, from both strategic and financial perspectives.
New units should be set up in the power sector until after they have credible assurance of NG supplies for a long term period that will ensure that their financial obligations on debt are fulfilled, and investors' payback is assured. This may be possible, only after the NG requirements of all the existing units are properly fulfilled

Gas Pricing

This is a contentious matter, which has till now been the purview of the GoI, and is not with the Petroleum and Natural Gas Regulatory Board.

Present Pricing Structures

There are a wide variety of prices prevalent in India, due to historical reasons. These are summarised below.

Table 41 Prevailing prices for Gas from various sources

	Source	Selling Price of Gas
1	NOCs' APM Gas	\$2.52 – \$ 4.2/mmbtu
2	NOCs' Non-APM Gas	\$5.25/mmbtu
3	PMT	\$ 4.2 – \$ 5.73/mmbtu
4	Ravva	\$ 4.2/mmbtu
5	Ravva Satellite	\$ 4.3/mmbtu
6	KG-D6	\$ 4.2/mmbtu
7	Niko-Hazira	\$ 2.673 – \$ 5.346/mcf
8	CB-OS/2	\$ 4.75 – \$ 6.22/mmbtu
9	CB-ONN-2000/2	\$ 6.6/mcf
10	Hermac	Rs. 9.02 – Rs.11.67/scm
11	Joshi Technologies (Dholka)	Rs. 4.80/scm
12	CBM	\$ 5.1 – \$6.79/mmbtu
13	Focus Energy (RJON/6)	\$ 4.11/mmbtu
14	HOEC (PY-1)	\$ 3.63/mmbtu

<u>APM and other supplies</u>
Gas produced from Nominated fields of ONGC & OIL is termed as APM gas.
It was allocated in the past as per the prevailing policies. These contracts cannot be changed.
The Government has distinguished between use of APM gas for core and non-core sectors, by differential pricing:

- Supplies to the core sector, namely power and fertilisers, are charged at \$ 4.2/mmbtu, and
- Supplies to Non-core sector, namely all othersectors such as refineries, petrochemicals, steel, CGD, LPG, are charged \$ 5.25/mmbtu; this is commonly called non-APM sector / price.

The quantity of APM gas is about 50 mmscmd, and non-APM gas is about 23 mmscmd.

Price build up

The above are the prices at the well head, or the delivery point at the gas producing location.
However, customers are usually located elsewhere. Gas has to be transported to that location through pipelines, which are owned by another entity such as Gail India Ltd, or Gujarat State Petronet Ltd., or Reliance Gas Transportation Infrastructure Ltd. They have to be paid their transmission charges.

The commercial structure requires the Buyer to enter into two separate contracts:

- one with the gas Seller for purchase of gas, called the Gas Sale and Purchase Agreement (GSPA), and
- another with the gas Transporter, for transmission of gas from the Seller's delivery point upto his plant. This is called a Gas Transmission Agreement (GTA). It is the responsibility of the gas Buyer to ensure that the Gas Seller transfers the correct quantity and quality of gas into the Transporter's pipeline. The Buyer is also responsible for removing the correct quantity of gas from the pipeline into his plant for his use.
- Often, the locations of Buyer and Seller are such that more than one pipeline is needed. In that case, the Buyer has to enter into independent contracts, and sign separate GTAs with each pipeline owner.

The taxation structure requires the Buyer to payCentral Sales Tax (if Buyer and Seller of gas are located in different States), or Value Added Tax (if Buyer and Seller of gas are located in the same State). Further, service tax is chargeable on the gas transmission charges. Since these are industrial activities, in most cases the Buyer is able to obtain set off credit for the VAT and Service Tax paid on the gas purchase and transmission charges.

Table 42 Cost Build up of KG D6 at customer end

Item	Rate
Ex-delivery flange $/mmbtu NCV	4.205
Marketing Margin $/mmbtu	0.135
Subtotal $ / mmbtu	4.34
In Rs / mmbtu at Rs 63/USD	273.4
CST 2%	5.5
Transmission– East West Pipe Line	67.0
Transmission – Hajira Bijaipur Jagdishpur Pipe Line	30.8
Transmission sub total	97.8
Total Cost NCV Rs / mmbtu	376.7
Total Cost NCV $ / mmbtu	5.98

There is strong pressure from the gas producers to increase the price of domestic NG.

Auction for CBM

One of the first events in this direction was the auction of CBM gas by Reliance Industries in February 2012. RIL required bidders to submit quotes based on the following formula:

Gas Price in US$/mmbtu on GCV basis at the Delivery Point = 12.67% * JCC + 0.26 + "V", where JCC is the price of Japan customs cleared crude oil in USD/ barrel, and "V" is a positive or negative biddable number in USD/ mmbtu. Buyer would also have to pay a Marketing margin of USD 0.15 per mmbtu, all taxes, duties and levies on the sale of gas, plus Transportation tariff and any taxes there on.

It will be noticed that this is the same formula used by Ras Gas Qatar to sell LNG to India, except for the V factor, which was introduced here only for the purpose of the auction. Just like LNG, this formula price was on GCV basis, which is a major change from the current practice of selling all domestic gas on NCV basis; as customers can use only the Net Calorific content of gas, the effective cost to them would be 10 - 11% more than the GCV figure. Thus, the supplier wanted to sell NG on total import parity, despite the fact that he does not have to incur any of the costs of liquefaction, overseas shipping, import duty, port charges, and re-gasification. Considering the shortage of NG in the country, the auction received tremendous response from all potential usage sectors in the country, including fertilisers, power, city gas, etc. RIL claimed that the highest bids placed V at zero, meaning that there was a section of buyers willing to buy at full import parity price. The bids have been submitted to the MoPNG, whose decision is awaited.

Auction for conventional NG GSPCL

The Gujarat State Petroleum Corp Ltd. held anE-auction in March 2013 for sale of NG it will be producing from Deen Dayal West gas field of Block KG-OSN-2001/3. It expected production to start in late 2013, and that the peak production would be 5.24 mmscmd in 18 - 24 months.

They also put forward a formula similar to that of RIL, which would provide parity with LNG: Gas Price in US$/mmbtu on GCV basis at Delivery Point= 12.67% * Brent crude price + 0.26 + / - V , where V is a positive biddable number in USD/ mmbtu, such that the Floor price of NG would be $ 8.5 / mmbtu, irrespective of V; also, the value of Brent crude oil would be subject to a floor of $ 65 and cap of $ 110/ barrel. As before, customers would also have to pay Marketing margin of Rs 10.21/mmbtu (5% annual escalation), all taxes, duties and levies on the sale of gas, and transportation tariff and any taxes there on as applicable .

The highest bids put V =0, i.e. some bidders willing to pay equivalent of LNG from Qatar. The bids have been submitted to the MoPNG, who felt that customers of each priority category should have been asked to bid separately, since each has different affordability. The suppliers felt that this would have led to cartelisation, with all players bidding the floor price. The final decision is awaited.

Proposed Price for NG from April 2014

There have been requests for increase in price from NG producers, especially from the participants in the KG D6 block, since the price fixed for them in September 2007 had mandated that the price would be revised after 01 April 2014.

Even ONGC has indicated that it is presently earning a margin of about $ 0.58/mmbtu when APM gas is sold at $ 4.21/mmbtu. This leaves them an effective margin after taxes &dividend of just US$ 0.21/mmbtu, which is not sufficient to support major investments in future gas projects or exploration.[73]

The Rangarajan committee was formed to look into various matters pertaining to Production Sharing Contracts, including the price matter. It submitted its report in December 2012.

The MoPNG prepared a Cabinet Note for obtaining approval of the pricing formula. "During the course of circulation of the Cabinet Note, the Planning Commission suggested a price of 11.18 $ per MMBTU, Ministry of Finance 6.99 to 8.93 $ per MMBTU, Department of Fertilizer 6.68 $ per MMBTU, whereas Ministry of Power opined that we should stick to the present cost plus regime which comes to around 4.14 $ per MMBTU." [74]

After further deliberations, the matter was taken to the Cabinet Committee on Economic Affairs, which on 28 Jun 13, approved the Natural Gas Pricing Guidelines, 2013for next five years, from April 2014 for all domestically produced gas, excluding some contractual cases.

These Guidelines derives competitive price of gas at global level by taking:
- First, netback price of Indian LNG term imports at the wellhead of exporting countries
- Second, taking weighted average of prices in major markets, viz (a) Henry Hub USA (b) National Balancing Point UK (for Europe), and (c) netback price at the sources of LNG supply for Japan.
- Third, taking a simple average of above prices. This will be deemed as economically appropriate estimate of arm's length competitive prices for India.

While no sample calculations have been made public, it is reported that the formula will increase domestic gas price to $ 8.4/mmbtu from April 2014, at the delivery point near the well head.

Impact of Proposed Price on Power sector

it is learnt that the Ministry of Power had expressed the following views on the proposal to increase price of NG:
- It estimated that a well head price of $ 8.4 / mmbtu would lead to a delivered price of about $12/mmbtu, which will make Fuel Cost of Generation around Rs 5.40/kwh. At that Fuel Cost, gas based generating stations may not get schedule on merit order basis; New gas based projects may become NPAs. In addition, the units will have to bear huge Take or Pay/ Ship or Pay penalty in the Gas Purchase and Transportation Agreements.
- Discoms will not be able to draw gas based power; but mayhave to pay the fixed cost of these plants.
- The power sector is the largest consumer of gas. If the gas price is too high for power sector, demand for gas will slump drastically,which is not in the interest of producers and consumers or the nation.
- Gas price for power sector should be fixed such that it is competitive against the competing fuel, coal.

A study conducted by the Indian office of ICF, an international consultancy firm in the energy area, has concluded that "There is virtually no demand for gas at $8.5/mmbtu from power sector– let alone for LNG with 14.5 % linkage".[75]This was the result of a simulation run on a linear programming model formulated by ICF for the power generation industry, containing data on all power plants in India, (fuel type, fuel source, fuel cost, PPA, tariff etc.), and having the objective function of calculating the despatch that leads to the systemwith the least cost of generation, taking into consideration constraints on fuel supply, transmission and others.

The fact that domestic gas prices are denominated in US Dollar terms causes fluctuations in exchange rate to impact the cost of gas for buyers. The large depreciation of the Indian Rupee vis-a-vis USD in recent months has made gas that much more expensive.

A sensitivity study shows that, at the NG delivered cost of $ 12/mmbtu (anticipated after April 2014), and an exchange rate of Rs 63/ USD, the overall cost of power is estimated at Rs 7/ kwh, on the basis of assumptions mentioned alongside.[76]

Table 43 Sensitivity Analysis for Power Cost vs NG cost and Exchange rate

Gas Price	Exchange Rate								
	55	57	59	61	63	65	67	69	71
6	3.8	3.9	4.0	4.1	4.2	4.4	4.5	4.6	4.7
8	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.7
10	5.4	5.6	5.8	5.9	6.1	6.3	6.4	6.6	6.8
12	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
14	7.0	7.3	7.5	7.7	7.9	8.2	8.4	8.6	8.9
16	7.8	8.1	8.3	8.6	8.9	9.1	9.4	9.7	9.9
18	8.6	8.9	9.2	9.5	9.8	10.1	10.4	10.7	11.0
20	9.4	9.8	10.1	10.4	10.7	11.0	11.4	11.7	12.0

Station Heat Rate -1850 Kcal/Unit
GCV - 9500 Kcal/scm
Specific Gas Consumption - 0.19 Scm/ Unit
Plant Load Factor - 85%
Gas Requirement - 3.97 MMSCMD/1000 MW
Ex Rate – Re 60/$

In comparison, the Power Purchase Cost for Utilities as Approved by SERCs for FY 2013-14 averaged Rs 3.38, with the highest being Rs 4.62/kwh. It would appear that gas based power plants would be outpriced after April 2014.

In case R-LNG is purchased in order to make up the deficit of domestic gas, it will be at a higher price of around $ 18 to 20/mmbtu, as shown in Table 33 Cost build up of Re-gasified LNG for buyer in another state. This will aggravate the cost situation, and make gas based power even more expensive.

Use of gas for peaking power plants

It may therefore be considered that gas based power plants should serve as peaking power plants.

During peak hours, when there is load shedding, industrial and commercial customers use DG sets, where power costs are Rs 14-17/Kwhr. It is estimated that upto ~23000 MW of power gets so generated, using ~ 8.5 MMT of HSD. Discoms also purchase power at higher rates for public distribution. Retail tariffs have been slowly increasing in recent years, in response to customers' willingness to pay more, and the need to improve financial health.

ICRA estimates that a dedicated peak power plant may operate for 8-10 hours per day, resulting in 30-40% PLF only. Its fixed costsper unit of power sold would be roughly thrice that of the base load gas based plants. The all inclusive power generation cost could be in the region of Rs 8-10/Kwh for gas cost $10-14/MMBTU. [77]

There is likely to be an adequate market for higher cost of power. However, in order for this to happen, some policy changes are needed. ICRA suggests:

– Penalties on DISCOMs by SERCs for load shedding beyond a reasonable level
– Minimum procurement of peaking power in the overall power procurement mix
– Suitable amendments in the agreements with gas supply companies.

At present, agreements for Gas supply and gas transmission require that the gas should be drawn continuously throughout the 24 hours. Variations of just 5 to 10% are allowed, failing which stiff penalties are levied. Take or Pay conditions are strictly enforced.

If NG is to be drawn only during peak power demand times, then Gas supply companies need to relax these conditions.

If these conditions are not relaxed, the gas based power plants will no longer be able to purchase gas. The total demand for gas will reduce drastically, since power sector is even today the largest customer for gas, and is expected to be so even in future. If gas supply companies wish to retain their sales levels, then they will need to find solutions to such issues.

If peaking policy is implemented, the requirement of NG for such plants will be proportional to their (reduced) PLF. Thus, overall demand for NG from the power sector, which is presently calculated at 85% PLF level, will reduce accordingly.

One alternative that may be thought of is to set up gas storage facilities, which would be continually replenished by the supplier, but the consumer will draw as per his requirement. Unfortunately, the storage of NG is a major problem, since its volume cannot be reduced by easily converting to a liquid. An attempt to build individual storage for a single peaking plant involves the following numbers: assume a plant of 125 MW, its gas requirements would be about 0.5 mmscmd on a continuous basis; if it is to run for say 8 hours a day, then it would require 0.17 mmscmd NG, which would have to be stored. So the storage facility should be of say 200,000 cubic metres. This is a very large storage tank, which would cost an enormous amount.

One option can be to compress the CNG, so that the volume will reduce. To get an idea, the case of CNG cylinders used in cars can be considered. The empty CNG cylinder fitted in cars has a 50 litre-water-carrying capacity and weighs 48 kg. The maximum pressure in a CNG cylinder is up to 200 kg/cm2(g).[78]

As per Gail, 1,000 litres of NG at a standard temperature and pressure weighs 0.76 kg. As per MNGL, the CNG cylinder in a car weighs 48 kgs and has a volume of 50 litres, and is filled with NG at pressure of about 150 kg/cm2g. This CNG will occupy a volume 150 times as much if it is at standard temperature and pressure, i.e. 50 litres (cylinder capacity) * 150 (pressure multiple) = 7,500 litres.
So if 200,000sm3 of NG is to be stored as CNG, then the weight of the containers required will be 128,000 tonnes. These unfavourable numbers make storage of large volumes of NG a difficult activity.As NG is flammable, it would also be subject to a host of safety features, including a large safety distances to be kept all around the tank.

It may not therefore be possible to attempt such storage on a standalone basis for a single small plant. It would have to be done through institutional means for which the concept has to be developed in dialogue with the various stakeholders.

A similar problem is faced in cold regions of Europe, USA and elsewhere, where demand for NG rises in winter for heating purposes. There, NG storage is widely practised on a large scale. Specialised companies are involved in NG storage, where they use salt caverns, depleted gas reservoirs, and aquifers. These storage facilities are then connected through pipelines to consuming centres. Obviously, there is a cost attached to all these facilities, including the interest cost of storage. Storage companies are also able to earn by buying when price is low, and selling when price is high.

A separate study will be required to see if such facilities can be created in India. As of now, it would appear that Gail is in the most suitable situation to conduct such a study and implement it.

Another possibility is to use abandoned coal mines for such storage of gas.[79]

Impact of Proposed Price on Fertiliser sector

The Department of Fertilisers has also expressed its reservations that the high price of domestic gas will increase the subsidy bill of the GoI, to levels that will create ever more serious cash flow problems for manufacturers.

According to the Mininster of State for Chemicals and Fertilisers, Mr. Srikant Jena, the cost of producingurea will rise by $ 25/MT for every $ increase in gas price. As about 18 million tonnes are presently produced from Natural Gas, the proposed gas price increase of $ 4.2/mmbtu will raise the national cost of producing urea by $ 1.89 billion, or Rs 11,900 crores (at Rs 63/$).

The arrears due to the Fertiliser companies as on 31 March 2013 were Rs 31,500 crores [80], which is about half of the Rs 65,974 crores provided toward fertiliser subsidy in 2012-13 (Revised Estimates). The Fertiliser subsidy is actually a reimbursement of costs incurred by the industry; its delay by a period of several months creates serious cash flow problems for manufacturers. Even today, the subsidies are so much delayed that the Fertiliser Association of India has filed a case in Delhi High court against the Department of Fertilisers in July 2013, seeking interest for non-payment of subsidy in the stipulated time of 45 days after the fertiliser issold[81].

The moot question is that if there is difficulty in paying the present subsidy amounts, then how will the additional burden be managed?

An increase in the retail selling price of Urea to farmers does not seem to be on the cards, since the price has hardly changed in the past decade.

Addition of New Capacities in Urea

Since the country imports about 25% of its urea requirements, the GoI has announced a New Investment Policy in 2012 to encourage investment in urea plants. Initially, about 20 units submitted proposals, for a total capacity of about 25 mil tpa urea. However, the continued shortage of NG has whittled this down to about four units.

The proposed increase in domestic gas price to $ 8.4 /mmbtu has created further problems for the new capacities proposed. It happens to coincide with a period of global over capacity in urea, which has pushed urea downwards from the $ 400 level to the $ 300 level (fob). FAI estimates that the cost of manufacturing urea at delivered gas cost of $ 12/mmbtu will be close to $ 375/mt. As shown below, this is close to the import parity price of urea.

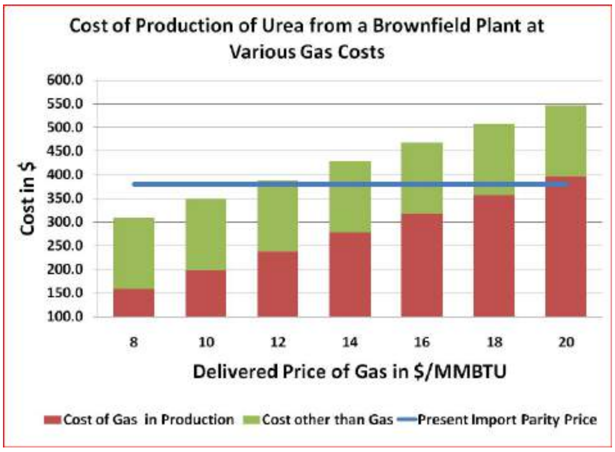


Figure 10 Urea: Import cost vs Production cost at different NG costs [82]

There is now a line of thinking which suggests that urea should be imported whenever it is cheaper than domestic production. In effect, this withdraws the guaranteed offtake clause provided in the Urea policy to new urea capacities. If this clause is removed, then the new urea capacities may have to sell their product in the global market; however, they would not be competitive, because if they were, then the GoI would have bought from them. Investors are now unsure about the viability of new urea capacities. Even if the guaranteed offtake clause is retained, investors are aware that the proposed domestic gas price makes domestic production uncompetitive against imports for next few years. So they will apprehend that the guarantee may be withdrawn some time or the other. In this high risk scenario, there is high possibility that the new capacities may not materialise.The nations' level of Food / Fertiliser security will reduce.

In this situation, there is a clear possibility that the future demand for NGfrom the fertiliser sector will remain at the present level, without any increase due to new capacities.

Effect on total demand for NG

It is thus seen that the increase in demand from the Power and fertiliser sectors may not materialise. It may stagnate at the present levels, which are:
Fertiliser sector: 57 mmscmd (Reference on page 66)
Power sector: 113 mmscmd (Reference on page 11)

Thus, the total demand for NG in the country may remain at the level of about 293 mmscmd forecast for 2012-13 (reference Table 3). Growth may continue in the non-price sensitive sectors such as City Gas, Industrial, Refineries, etc. As this reduces the total volume of NG sales, the impact on the pipeline and LNG sectors needs to be evaluated.

As regards, City Gas, a demand projection from Crisil forecasts slower growth, with demand reaching only 40 mmscmd by 2020 [83], as against 55 mmscmd in the forecast for the 12th / 13th Plan. CGD is operational in around 50 cities with another 200 cities identified for roll out. However, the fourth round of bids was indefinitely postponed in 2012, and has not occurred yet. CGD growth can occur only after more bidding rounds are held.

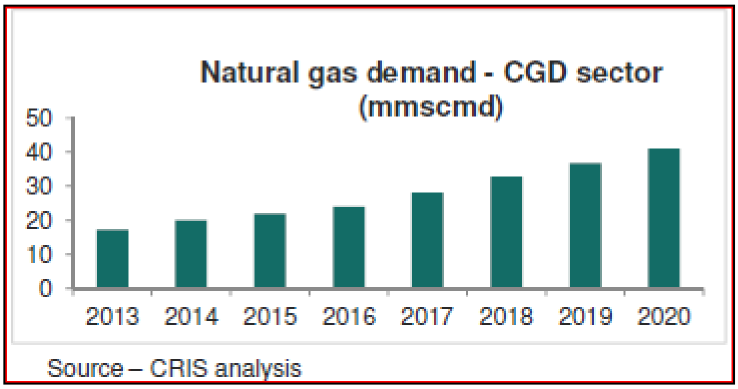


Chart 12 Crisil's estimate of CGD demand

Crisil estimates that the weighted average affordability of CGD (at 100 $/ bbl crude cost) is in the range of $ 18- 19 / mmbtu at city gate station, considering that it has to compete with Domestic LPG, Commercial LPG, Diesel, and Furnace Oil. If prices of LPG, petrol and diesel are gradually freed, then the affordability of LNG for CGD will increase.

Thus, CGD can support the expansion of NG infrastructure in coming years.

Conclusion

The proposed increase in domestic gas prices to above $ 8/ mmbtu ex-wellhead is likely to make the two major consuming sectors uncompetitive:

- manufacture of fertilisers with respect to imports, and
- generation of power vis-a-vis the coal sector.

The anticipated growth in demand from these sectors may not materialise. Existing plants may continue to operate, but addition of new capacities will be affected.

Gas based power plants may be run intermittently to meet peaking load, provided that Take or Pay clauses are modified to enable them to draw NG intermittently as per requirement; policy support may also be needed from Electricity regulators.

The reduction in demand from Fertiliser and power sectors will mute the demand for LNG, as domestic NG may suffice to meet needs of remaining sectors. The number of terminals required may reduce. This can affect the need for pipeline capacity. These will now have to depend on growth of CGD, which is also subject to revival of the bidding process.

It is seen that the large quantum of NG may be availablefrom unconventional sources, such as CBM, shale, UCG, petcoke and hydrates. However, these will take time to fructify. Even so, these need to be encouraged for us to be able to obtain the benefits of the resources available in the country. More technology development is required in these areas.

In sum, it is seen that the scope for generating additional power by expanding gas based capacity is presently limited by both supply and pricing of NG. Alternate fuels should be considered for augmenting power capacity.

Annexure 1

Technical Abbreviations

Abbreviation / Definition	Full form	Usage
Measures of QUANTITY		
BCM	Billion cubic metres	To describe large volumes of NG, e.g. quantity used in a year, or for size of resources
BCF	Billion cubic feet	Same as above. Used in USA. 35.3 cubic feet = 1 cubic metre
TCF	Trillion cubic feet	Used for size of resources or reserves
Mmscmd	Million Standard Cubic Metres Per Day	Quantity of gas per day.
Mmscfd	Million Standard Cubic Feet Per Day	Same as above. Used in USA.
MMT	Million Metric Tonnes	Used for crude oil, and for Liquefied Natural Gas (LNG). As the name signifies, LNG is a liquid, and is transported by ship, where its quantity is measured in metric tonnes.
mmtoe	million tonnes of oil equivalent	When quantities of oil and NG are reported together, the NG is converted to equivalent quantity of oil. The combined total is then measured in terms of this hybrid unit. 1 million barrels oil equivalent = 5.61 BCF = 0.16 BCM
Measures of HEAT CONTENT		
GCV, or **GHV, or** **HHV**	Gross Calorific Value, or Gross Heating Value, or Higher Heating Value	Measure of heat content in the NG supplied. The three terms are synonymous
NCV or **NHV or** **LCV**	Net Calorific Value or Net Heating Value or Lower Calorific Value	Measure of heat content available to the user of NG. The three terms are synonymous

Annexure 2
Some Important Definitions:

GCV and LCV:
In the determination of gross calorific value, the products of combustion are cooled to 15°C. This means that almost all of the water vapour, whether formed from the combustion of the hydrogen within the fuel or through the evaporation of the fuel's moisture content, is condensed to liquid water. This condensation gives up latent heat, which is therefore included in the GCV.

Since this latent heat is not recoverable in combustion plant such as boilers, it ought to be discounted. This results in the Net Calorific Value or NCV, which is more representative of the heat obtainable in practice from the combustion of the fuel.

The difference between GCV and NCV depends on the moisture content and the hydrogen content of the fuel. For natural gas, which is effectively dry and is composed predominantly of methane (25% hydrogen and 75% carbon by weight), NCV is approximately 10% lower than GCV. For most dry fuels the difference is less than 10%, typically 4% – 6% for coals and oil fuels. For wood containing 60% moisture the ratio NCV/GCV is approximately 0.75.[84]

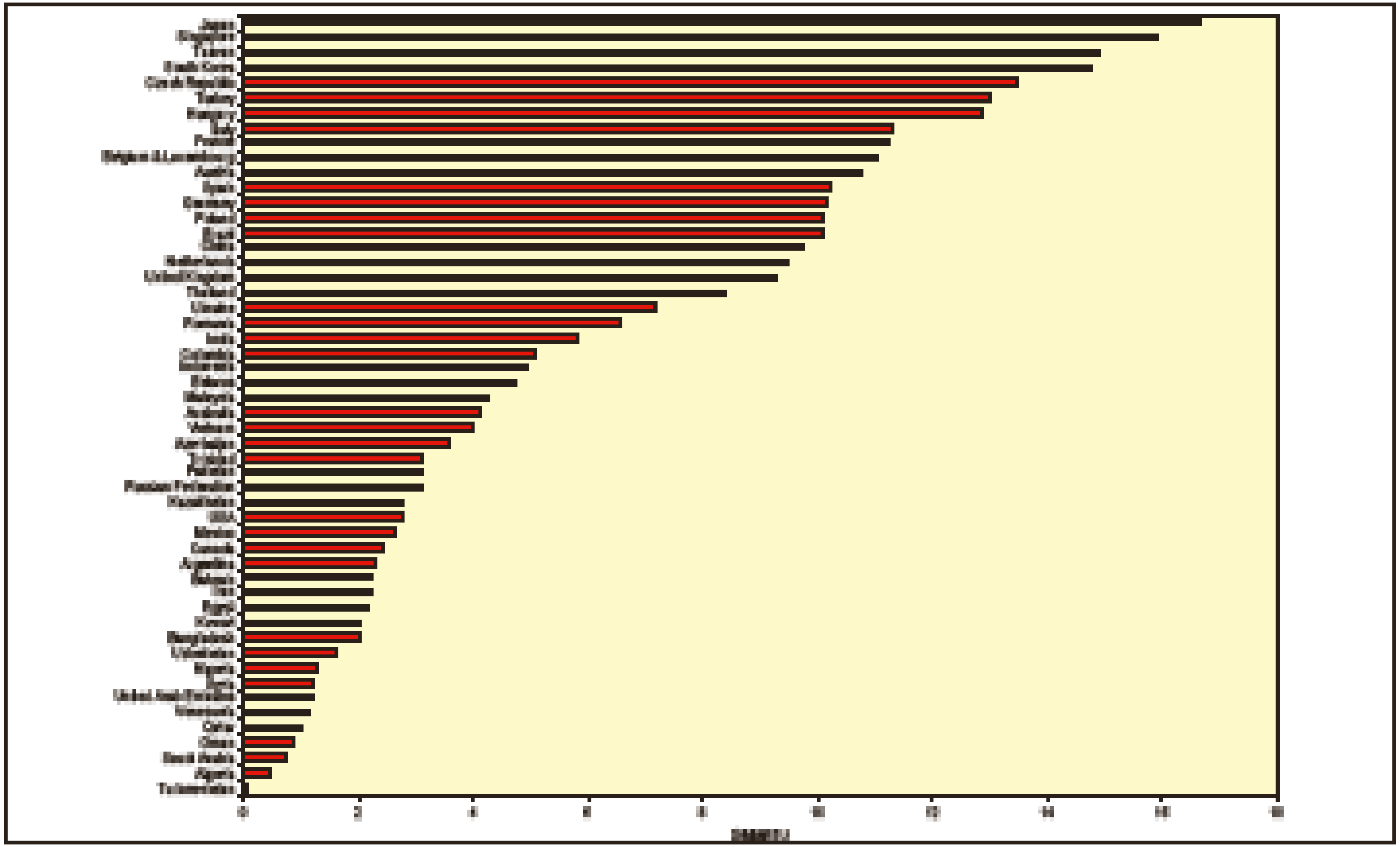
Resources vs Reserves:
the measurement of how much oil or NG is present deep under the ground is estimated by trained geologists who interpret the data generated by a variety of instruments and techniques. Perfection is not possible.

1) Lead = potential accumulation that needs more data
2) Prospect = potential accumulation that has enough data to be a viable drilling target
3) Contingent Resource
4) Reserve

Annexure 3
General Abbreviations

E&P	Exploration & Production
CBM	Coal Bed Methane
DGH	Directorate General of Hydrocarbons
GAIL	Gail India Ltd
GSPC	Gujarat State Petroleum Corporation
HLPL	Hazira LNG Private Limited
JCC	Japanese Custom Cleared crude oil price
MoPNG	Ministry of Petroleum and Natural Gas
NELP	New Exploration Licensing Policy
NG	Natural Gas
OIL	Oil India Ltd.
ONGC	Oil and Natural Gas Corporation Ltd
PLL	Petronet LNG Ltd
PNGRB	Petroleum and Natural Gas Regulatory Board
RIL	Reliance Industries Ltd

Figure 3.16. Wholesale Prices in 2012 by Country



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ANNEXE 3

METHODOLOGY FOR QUANTIFYING PREFERENCES ACROSS EVALUATIVE SUB-ATTRIBUTES & PAIRED COMPARISON SCORES

Annexe 3

Methodology for quantifying preferences across evaluative sub-attributes & Paired comparison scores

In its present form, the main comparison tool, the TA matrix is a multi-dimensional matrix having a mix of quantitative and qualitative data for 16 technologies across 18 sub-attributes. It should be appreciated that none of the considered technologies are superior to other technologies across all attributes and in such a scenario, combining weightages, (which are numbers), with the matrix cell data, (which can be a quantity or a narrative), and deriving a priority order through narrative logic based arguments does not seem to be possible.

The alternative to not using the tool is to derive technology priorities without considering weightages but even this can be done only through an opaque mechanism that will subconsciously consider only some sub-attributes, (depending on who looks at it), while totally discounting others. And in this case, the weightages assigned to the main attributes will be of no consequence.

Considering the difficulty of evaluating technologies across all attributes, the project team realized that it was relatively easy to define technology preferences across each evaluative sub-attribute. This realization served as a basis to combine sub-attribute-level weightages with the sub-attribute level preferences to derive the final order of priority.

In this background, quantifying the analysis seems to be the only possible way to integrate weightages with the data/narrative in the TA Matrix.

Quantification of preferences – Methodology

As the evaluative parameters are a mix of qualitative and quantitative data, the method used for quantification is based on a linear paired comparison scale. To ensure commonality between comparisons across qualitative parameters, qualitative preference statements were converted into a quantitative preference scale assuming one technology as reference. The representation made apaired comparison of the reference technology with all other technologies using a defined scale to transform preferences into an interval scale. Quantitative data based comparisons were also converted into this scale. Figure 1 demonstrates the use of the scale for paired comparisons across attributes. Figure 2 explains the preference scale.

Row Item as compared to Column Item

Sub-attribute 1	T1	T2	T3	T4
T1	50	52.5	20	15

Sub-attribute 2	T1	T2	T3	T4
T1	50			

Sub-attribute 3	T1	T2	T3	T4
T1	50			

Preference Scale	
0-10	Extremely Not Preferable
10-25	Highly Not Preferable
25-45	Moderately Not Preferable
45-50	Marginally Not Preferable
50	Equally Preferable
50-55	Marginally Preferable
55-75	Moderately Preferable
75-90	Highly Preferable
90-100	Extremely Preferable

Figure 1 Preference scale and paired comparison table *(refer narrative)*

Preference Scale		Explanation of scale
0-10	Extremely Not Preferable	Same as 'Extremely Preferable' except in reverse order
10-25	Highly Not Preferable	Same as 'Highly Preferable' except in reverse order
25-45	Moderately Not Preferable	Same as 'Moderately Preferable' except in reverse order
45-50	Marginally Not Preferable	Same as 'Marginally Preferred' except in reverse order
50	Equally Preferable	The performances/characteristics for the attribute/sub-attribute considered are exactly the same between the two technologies
50-55	Marginally Preferable	There is only a slight difference in the performances/characteristics between the two technologies. The difference is very small but needs to be noted.
55-75	Moderately Preferable	There is a noticeable difference in the performances/characteristics between the two technologies across the attribute/sub-attribute, which needs to be highlighted.
75-90	Highly Preferable	The difference between two technologies is significant and has to be explicitly factored in the analysis
90-100	Extremely Preferable	The difference between technologies is the highest possible in the sense that the two technologies represent exactly contradictory preferences for the sub-attribute under consideration. This range is only used under exceptional cases with clear justification for the use of this scale.

Figure 2 Preference scale and its explanation

For each paired comparison, T1 (or any arbitrary technology) earmarked as the reference technology is assigned a value of 50 and all other technologies are then compared with T1 using the preference scale as shown in Figure 1.

For example, if for sub-attribute 1, T1 is assessed to be marginally preferable to T2, the corresponding value in the T1T2 cell should be in the range of 50-55. We start by assigning a value of 52.5 (average of the range). Moving on, based on TA matrix comparisons, if we perceive T1 to be highly not preferable to T3, the corresponding values in the T1T3 cell will be 17.5 (mid range value for the range 10-25).

If now T4 is also considered to be highly preferable to T1, (or T1 is highly not preferable to T4), the value of the T1T4 cell will also be 17.5. After the filling of all cells, the cells having common valueswill be considered and technologies evaluated. For example as in this case, both T3 and T4 are at 17.5, they will be compared and if it is assessed that T4 is marginally preferable to T3 then the values of T1T3 and T1T4 cells will be modified accordingly to 20 and 15 using the spread of the range 10-25 (Values will be reassigned in multiples of 2.5. If there is only a marginal difference a value of 2.5 will be added or deducted from the already assigned value, for a moderate difference a value of 5 will be used, for high difference a value of 7.5 and so on). Care will be taken to avoid extreme range values so as to maintain the distinction between each preference scale range. It is to be noted that that most of the quantitative data, (Capex, emissions, etc.), will also be transformed into a similar preference scale. It is also to be noted that values are assigned to the preference scale based on the inputs derived from the TA matrix.

It is to be further noted that the specific use of the preference scale is in line with standard conventions used in paired comparisons where cell quantities indicate row item preference values as compared to column items. Understandably, the proposed representation suggests that the lower the value, the better the technology across that sub-attribute.

The next step will be a simple mathematical operation of multiplying sub-attribute level weightages with the preference scale values of each technology and summing up the product across each technology to derive the final weighted value of that technology. Mathematically, the equation for deriving the final weight of technology, $T_{a,}$ is shown below

Final weight T_a = $_{i=1\ to\ n}\Sigma$ Weight of ith Sub-attribute, x Preference score of T_a across the ith sub-attribute **(eq. 1)**

The final weights of all technologies are derived using equation 1. Based on the adopted methodology, technologies with a lower score will be accorded a higher order of priority.

A graphical representation of the methodology is shown in Figure 3.

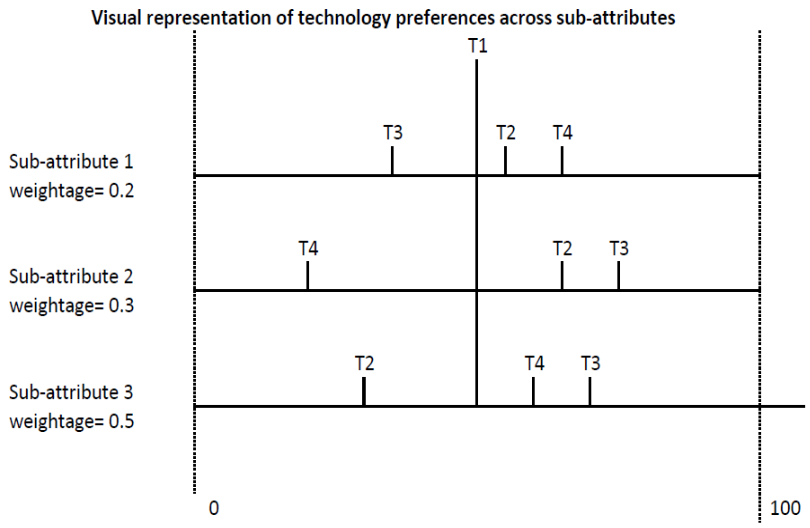

Figure **3** Graphical representation of the preference scoring methodology

Explanation of preference scores

For the purpose of representation in the comparison table, each technology/ sub-technology/resource is assigned a specific nomenclature, T1 to T16, as given in the table 1 below.

Table 1 Technology Nomenclature

Technology Nomenclature	
T1	Supercritical PC with Domestic coal
T2	Supercritical PC with Imported coal
T3	Supercritical CFBC with Domestic coal
T4	Supercritical CFBC with Imported coal
T5	Ultra supercritical PC with Domestic coal
T6	Ultra supercritical PC with Imported coal
T7	IGCC with Domestic coal
T8	IGCC with Imported coal
T9	UCG
T10	OCGT with Domestic gas
T11	OCGT with Imported gas
T12	CCGT with Domestic gas
T13	CCGT with Imported gas
T14	RoR
T15	Storage Based Hydro
T16	Pumped Hydro

As explained in the methodology, for the purpose of paired comparison, one technology is chosen as the reference technology. **In this exercise, Supercritical PC with domestic coal is chosen as the reference technology (T1) and is** compared with each technology using paired comparison. The following narrative covers the paired comparison scores for each attribute.

Sub-attribute - GHG emissions in CO2 equivalent
Weightage: 9.2
Main Attribute/: Climate

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	42.5	47.5	42.5	42.5	40	42.5	40	30	40	40	17.5	17.5	5	5	5

The preference score for "climate" is evaluated based on the CO_2 equivalent footprint of each technology. With reference to the sub-matrix in Chapter 4 in the main report, supercritical PC with domestic coal, the reference technology, has the highest CO2 footprint of 0.94 kg/kWh among all technologies, with hydro technologies having the lowest emissions at 4-14 g/kWh.

Supercritical CFBC (domestic coal) with a value of 0.9 kg/kWh of CO2 equivalent is assessed to be marginally superior and is assigned a score of 47.5.

Supercritical PC (imported coal), Supercritical CFBC (Imported coal), Ultrasupercritical PC (domestic coal), Ultrasupercritical (imported coal), IGCC (domestic coal), IGCC (Imported coal), OCGT, all with average values of around 0.85 kg/kWh of CO2 are assessed to be moderately preferable to T1. UCG with a lower emissions footprint of 0.7kg/kWh is also considered as moderately preferable. An initial score of 35 is assigned to all these technologies.

On the other hand, CCGT technologies (both domestic gas and LNG) with an emissions footprint of 0.5-0.6kg/kWh are assessed to be highly preferable and are assigned a score of 17.5. Hydro technologies are considered to be extremely preferable to the reference technologies and are assigned a score of 5.

As the next step, all the technologies having the same preference scores are compared to each other to find their relative preferences and the spread of the range is used to work out scores of different technologies. Ultrasupercritical, IGCC and OCGT are assessed to be less preferable to UCG. Further, considering the marginal difference in emissions value of Ultrasupercritical and IGCC based on imported coal as compared to domestic coal, imported coal based choices are given a marginally higher preference.

Based on this assessment, the final scores are shown in the paired comparison table above

Sub-attribute - Air Pollution (SPM, SOx, and NOx)
Weightage: 5.72
Main Attribute: Environment

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	50	22.5	22.5	47.5	47.5	35	35	12.5	15	15	12.5	12.5	5	5	5

Preference score for “air pollution” is evaluated based on the SOx, NOx and SPM footprint of the technology per unit of generation. Supercritical PC with domestic coal is compared with the every other technology on the basis of the quantitative value of SPM, SOx, and NOx emissions. From the TA matrix it became evident that there is hardly any notable difference in the emission characteristics of a technology due to domestic or imported based fuel. Supercritical PCwith domestic coal, (SO2 - 3.3 g/ kWh, SPM - 0.12 g/ kWh, NOx - 1.0 g/ kWh) has the highest emissions in the suite of technologies, while hydro technologies (RoR, storage based and pumped hydro) emit negligible SOx, SPM and NOx. Therefore hydro based technologies can be considered as extremely preferable over supercritical PC and a preference choice of 5 is assigned to the hydro technologies

Ultra supercritical PC having slightly lower emission characteristics (SO2 - 3.2 g/kWh; SPM - 0.1 g/kWh;NOx – 0.96 g/kWh) becomes moderately preferable over the reference technology.Therefore a preference score of 47.5 is assigned to Ultrasupercritical PC(domestic and imported coal). Supercritical CFBC have significantly lower SO2 and SPM emissions (SO2 - 0.4 – 0.8 g/kWh; SPM - 0.12 g/ kWh; NOx - 0.2 – 0.25 g/ kWh) than supercritical PC. UCG, OCGT and CCGT have negligible SO2 and SPMemissions. Eventhough they emit small quantities of NOx, they can be considered as highly preferable over supercritical PC Therefore a preference value of 17.5 is initially assigned to supercritical CFBC, UCG and OCGT. IGCC having lower emissions level (SO2 - 0.7 g/ kWh, SPM - 0.04 g/ kWh, NOx – 0.4 g/ kWh) can be considered to be moderately preferable over the reference technology and a preference value of 35 is assigned

The next step involves comparing the technologies having the same score. UCG and CCGT, with almost the same emission characteristics, are found out to be highly preferable among these technologies and therefore the lowest value of 12.5 in the range was assigned to these technologies. Supercritical CFBC is the most inferior technology among the cluster and therefore 22.5 isassigned to this technology. OCGT was moderately preferred over Supercritical CFBC and according to the percentage variation in emission; a value of 15 was assigned to the technology

Sub-attribute - Water use & Pollution
Weightage: 5.78
Main Attribute: Environment

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	42.5	50	42.5	47.5	40	35	27.5	27.5	12.5	12.5	22.5	22.5	5	5	5

The preference score for "water use and pollution" is evaluated based on the extent of the impact of the concerned technology on water in terms of consumptive water use and in terms of generating untreatable waste water. Based on the sub-attribute matrix, supercritical PC domestic coal appears to have the highest water consumption of 2.2 - 2.5 m3/MWh with hydropower technologies having very limited water consumption (other than water losses from evaporation). The water pollution impacts from lifecycle generation, including coal mining and transport, also appear to be the highest for this technology.

Imported coal based supercritical technologies avoid the water pollution and the impact of water use related to coal mining (acid drainage, drainage of leachates, etc.) and are assessed to be moderately preferable to domestic coal based technologies and are assigned a value of 35. Ultra supercritical PC with a slightly lower water consumption of 2.1 - 2.2 m3/MWh than the reference technology is assessed to be marginally preferable to supercritical and is assigned as score of 47.5.

IGCC and UCG are also assessed to be moderately preferable to domestic coal based supercritical PC technology and are assigned an initial preference score of 35. OCGT consumes negligible water for operation and CCGT consumes 0.8 - 1.0 m3/MWh for operation. These values are significantly low as compared to supercritical PC and therefore OCGT and CCGT are assessed to be highly preferable to supercritical PC technology and a value of 17.5 is assigned to these technologies.

Considering the low water use values of hydro in addition to lower water pollution impact, all hydro technologies are assessed to be extremely preferable to the reference technology (supercritical PC based on domestic coal) and are assigned a value of 5.

In the next step imported coal based technologies, UCG and IGCC with scores of 35 are compared to assess their relative preference. IGCC (imported coal) and UCG is assessed to be highly preferable to imported coal based technologies and hence IGCC (imported coal) and UCG are reassigned a score of 27.5, while imported coal based technologies are reassigned a score of 42.5. Among imported coal based technologies, Ultrasupercritical technology is assessed to be marginally preferable to supercritical technology and is reassigned a score of 40. For gas based technologies, with scores of 17.5, the high difference in water consumption between OCGT and CCGT is captured by spreading the scores from the average with OCGT reassigned a score of 12.5 and CCGT reassigned a score of 22.5.

Sub-attribute - Land Diversion and Land Use
Weightage: 3.69
Main Attribute: Environment

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	27.5	52.5	27.5	42.5	27.5	50	27.5	12.5	17.5	12.5	22.5	17.5	35	47.5	47.5

The preference score for "land diversion and pollution" is evaluated based on the potential of the technology to divert land from other uses (forests, agriculture) and its ultimate impact of land pollution that results in the change of land use. Supercritical PC with domestic coal is compared with every other technology on the basis of the quantitative value of land diversion for plant and mining, and qualitative impacts on land use.

Based on the sub-attribute matrix in Chapter4, the land requirement for domestic coal based technologies is assessed to be significantly more than that of technologies based on imported coal, considering the significant impact of coal mining on land use. It is assessed that even after considering the land use in importing coal and associated transport, the overall land use impact of imported coal will still be moderately less than that based on domestic coal. Supercritical PC, CFBC, Ultra supercritical PC, IGCC based on imported coal, are therefore assessed to be moderately preferable as compared to supercritical PC (domestic coal) and are assigned an initial value of 35.

For domestic coal capacities, Supercritical CFBC with domestic coal with a land area requirement of 1.1-1.2 Acres/MW as compared to 1.04 Acres/MW for supercritical PC (domestic coal) is assessed to be marginally inferior and is assigned a preference score of 52.5. Ultra supercritical PC with domestic coal with a moderately lower area requirement of 0.77 Acres/MW as compared to supercritical PC (domestic coal) is assessed to be moderately preferable and is assigned an initial score of 35.

Compared to the reference technology, land requirements of UCG, OCGT and CCGT are significantly lesser than those of supercritical PC and are assigned an initial value of 17.5. However, considering the difference between land use of domestic gas based capacities (from gas extraction to transport) as compared to imported gas (LNG) and the difference in the plant sizes between OCGT and CCGT, imported gas based OCGT is assessed to be marginally preferable to domestic gas based OCGT and moderately preferable to imported gas based CCGT. Based on this assessment, the scores assigned to OCGT (Imported gas) and CCGT (Domestic gas) are reassigned as 12.5 and 22.5 respectively. UCG with the lowest land use is assessed equally preferable to OCGT with imported coal and is assigned a score of 12.5.

While hydro technologies have the potential to divert huge tracts of land, it is assessed that the land diversion potential of hydro is almost the same, or probably lower, as compared to coal based technologies if we consider the lifetime land use and land pollution impact of coal mining compared to those of hydro. Based on this, storage based and pumped storage hydro technologies are assessed to be marginally preferable to supercritical PC (domestic coal) and are assigned a score of 47.5. Run of the River with pondage is assessed to have lower land use and pollution impacts and is assigned a score of 35.

Sub-attribute – Loss of Biodiversity
Weightage: 4.2
Main Attribute: Environment

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	20	50	20	50	20	50	20	35	35	15	35	15	65	82.5	82.5

The preference score for "loss of biodiversity" is evaluated based on the potential for loss of biodiversity in terms of loss of fauna and flora and endemic species. The comparison of technologies for this sub-attribute is based on qualitative data. In this context, the impact of resource type (domestic or imported) has a significant impact on land use and biodiversity loss.

Based on the sub-attribute matrix in chapter 4, Supercritical PC, CFBC, ultra supercritical PC and IGCC using domestic coal are assessed to have higher impact on biodiversity loss as compared to technologies based on imported coal. All the domestic coal based technologies are assigned a preference score of 50, the same as the reference technology- supercritical PC based on domestic coal.

The technologies based on imported coal, OCGT and CCGT based on imported gas were found to be extremely preferable due to the complete absence of local mining as compared to the domestic coal based technologies. Major impacts would be related to *loss* of coastal habitats and depletion of marine resources and aquatic species due to thermal pollution. But these would be significantly lower than that of coal mining. Initially a preference value of 17.5 was assigned to all technologies based on imported fuel. Imported coal based technologies are assessed to be highly preferable and are assigned a score of 17.5. OCGT (Imported gas) and CCGT (Imported gas) with significantly lower impact are also assigned a preference score of 17.5.

UCG has minimum impact on biodiversity due to absence of coal mining compared to other domestic based coal technologies. OCGT and CCGT with domestic gas cause some extent of loss of biodiversity due to gas extraction and pipeline infrastructure, though they are considerably less than domestic coal.UCG, OCGT and CGGT based on domestic gas are assessed to be moderately preferable to domestic coal based technologies and are assigned a score of 35.

Loss of biodiversity in hydro development can be due to the construction activities involved in building the dam, embankments and power plant, the modification of river flow, possibly generating major ecological changes. Loss of biodiversity is the highest in the hydro projects among all the technologies. Run-of-river (ROR) hydropower plants are generally less damaging than reservoir power plants, because of the absence of a large reservoir for storage. Hydro technologies, mainly storage and pumped storage, are assessed to have an even higher impact on biodiversity compared to domestic coal based technologies as these imply the loss of rich riparian vegetation and animals through submergence. These technologies are assessed to be highly not preferable and are assigned a score of 82.5. RoR with limited impacts, mainly because of changes in river flows, is assessed to be moderately not preferable to the reference technology and is assigned a value of 65.

It is further assessed that OCGT and CCGT based on imported gas are assessed to be moderately preferable to imported coal based technologies considering their lower land use requirements because of the absence of coal handling, ash handling, etc. Based on this assessment, OCGT and CCGT based on imported coal are reassigned a score of 15 (from 17.5), while imported coal based technologies are reassigned a score of 20.

Sub-attribute - Public Health
Weightage: 5.62
Main Attribute: Society

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	35	50	35	50	35	35	22.5	12.5	17.5	17.5	17.5	17.5	5	5	5

The preference score for "public health" is evaluated based on the extent of the impact of the concerned technology on public health due to emissions and pollution (land, air, water). The comparison is mainly in qualitative terms. Based on the sub-attribute matrix in Chapter 4, a clear distinction is drawn between domestic coal based capacities and imported coal based capacities considering the adverse health impact of coal mining. All the domestic coal based supercritical and Ultrasupercritical technologies are assigned a preference score of 50- the same as the reference technology, supercritical PC with domestic coal. All imported coal based capacities, are assessed to be moderately preferable and are assigned a preference score of 35.

IGCC based on domestic coal is however assessed to be moderately preferable considering its better performance in controlling air pollution and is assigned a preference score of 35. IGCC (Imported coal), UCG, OCGT and CCGT are assessed to be highly preferable to the reference technology and are assigned an initial score of 17.5. Hydro based technologies are re-assessed to be extremely preferable and are assigned a score of 5.

In the next step, IGCC (imported coal), UCG, OCGT and CCGT, which are assigned an initial preference score of 17.5 are compared with each other. Among these technologies, it is assessed that UCG and CCGT seem to be highly preferable to IGCC (Imported coal) and moderately preferable to OCGT. Based on this assessment, UCG and CCGT are reassigned a score of 12.5 and IGCC (imported coal) is reassigned a score of 22.5.

Sub-attribute – Displacement Potential
Weightage: 4.35
Main Attribute: Society

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	37.5	50	37.5	50	37.5	50	37.5	30	32.5	30	32.5	30	65	82.5	82.5

The preference score for "displacement potential" is evaluated based on the potential of the technology for displacement of people (mainly small village people and tribal) from their natural habitat/shelters. Supercritical PC with domestic coal is compared with the every other technology on the basis of qualitative data. Based on the sub-attribute matrix in Chapter 4, a clear distinction is drawn between domestic coal based capacities and imported coal based capacities considering larger displacement potential from coal mining. Considering the large difference in the displacement potential of plant infrastructure as compared to coal mining, differences in infrastructure related displacement are not captured.

Based on this, all domestic coal based supercritical, Ultrasupercritical and IGCC technologies are assigned a score of 50- the same as the reference technology. Imported coal based capacities are assessed to be moderately preferable to domestic coal based capacities and are assigned an initial preference score of 35.

UCG, OCGT and CCGT technologies are also assessed to be moderately preferable to domestic coal based technologies considering the potential for displacement due to gas extraction, gas drawal and transportation (extraction and pipelines in case of UCG and domestic gas and port and pipeline in the case of imported gas). All these assigned an initial score of 35.

Among hydro technologies, storage based hydro and pumped storage are assessed to be highly not preferable to domestic coal technologies considering the submergence of large areas near river valleys that are more densely populated. They are assigned a preference score of 82.5. RoR with pondage, with a relatively lower displacement potential impact is still assessed to be moderately less desirable than domestic coal based technologies and is assigned a score of 65.

All imported coal based technologies, all gas based technologies and UCG, which are assigned a preference score of 35, are compared to reassign scores. Domestic gas based technologies, which are considered marginally preferable to imported coal based technologies, are reassigned a preference score of 32.5 while imported coal based technologies are reassigned a score of 37.5. UCG and imported gas based technologies are assessed to be marginally preferable to domestic gas based capacities are therefore reassigned a score of 30.

Sub-attribute – Employment Generation
Weightage: 3.06
Main Attribute: Society

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	65	50	65	50	65	50	62.5	62.5	67.5	70	65	67.5	65	62.5	62.5

The preference score for “employment generation” is evaluated based on the potential of a technology to create employment through its life cycle (employment generation potential from the resource extraction stage to final delivery of electricity at the generator bus bar. The comparison of technologies for this sub-attribute is based on quantitative and qualitative data. A clear distinction is drawn between domestic coal based capacities and imported coal based capacities considering the larger employment generation potential from coal mining. Domestic coal mining is assessed to generate the highest employment of approximately 3.88 persons/MW. Manpower requirement during construction and operation are almost similar for all coal based technologies

Supercritical PC, CFBC, ultra supercritical PC and IGCC using domestic coal are assumed to have the same employment generation potential and so the preference score of 50 is assigned to these technologies. Imported coal technologies, which generate a lower number of employments because of the absence of coal mining are assessed to be marginally not preferable and are assigned an initial preference score of 65.

UCG, OCGT, CCGT based on domestic and imported gas were also assessed to have lower potential for employment generation (for extraction, transport and operation) and a preference score of 65 is assigned initially. Hydro technologies with an operations support requirement of1.9 persons /MW are assessed to have for permanent employment and are therefore also assigned an initial preference score of 65.

In the next step, all imported coal based technologies, all gas based technologies, UCG and hydro technologies, which are assigned a preference score of 65 are compared to reassign scores. IGCC (imported coal), UCG and hydro based technologies are assessed to have marginally higher employment generation potential as compared to imported coal but moderately higher preference as compared to domestic gas based technologies. Imported gas based technologies are assessed to be the least preferable from an employment generation perspective. Based on this assessment, IGCC (imported coal), UCG and hydro technologies are assigned a score of 62.5

while OCGT(domestic gas) and CCGT(imported gas) are reassigned a score of 67.5. OCGT (imported gas) is assessed to be marginally less preferable to OCGT (domestic gas) and is reassigned a score of 70

Sub-attribute -Cost of Generation

Weightage: 7.59

Main Attribute: Economy

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	60	50	60	50	60	70	70	60	77.5	87.5	70	82.5	52.5	62.5	67.5

The preference score for "cost of generation" is evaluated based on the expected range of cost of electricity ex-bus as estimated by a regulator expressed in Rs/kWh. The comparison of technologies for this sub-attribute is based on the quantitative data available on calculated cost of generation. The high cost of imported gas, makes cost of generation of gas based technologies using imported gas the highest among the fleet of technologies.

Costs of generation of Supercritical PC, Supercritical CFBC, and Ultra supercritical PC with domestic coal are in the same range of 2.1-2.8 Rs/kWh. The slight variation in the cost of generation of each of these technologies is not considered in the scoring and these technologies are considered to be equally preferable and a preference score of 50 is assigned to them. International coal based Supercritical PC, Supercritical CFBC, Ultra supercritical PC, and UCG (domestic coal),IGCC with domestic/international and CCGT (domestic gas) withhigher cost of generation between the ranges 3.2-5 Rs/kWh are assessed to be moderately less preferable and assigned an initial score of 65.

OCGT with domestic gas (5.8 Rs/kWh), imported gas (11 Rs/kWh) and CCGT with imported gas (8 Rs/kWh) are assessed to be highly less preferable to the reference technology - supercritical (domestic coal) and are therefore assigned a preference score of 82.5.

Based on the sub-attribute matrix in Chapter 4, RoR is considered to be marginally less preferable to the reference technology and is assigned a value of 52.5. Storage and pumped hydro are assessed to be moderately less preferable and are assigned an initial preference score 65.

In the next, step, imported coal based technologies, UCG, domestic gas based technologies and storage based hydro technologies, with an initial score of 65 are compared. Considering higher costs, IGCC is assessed to be highly less preferable as compared to other imported coal based technologies. Based on this assessment IGCC and CCGT (domestic gas) with costs in the range of Rs 4-5/kWh are reassigned a preference score of 70 while other imported coal based technologies and UCG are reassigned a score of 60. OCGT (domestic gas) is assessed to be moderately preferable to CCGT (imported gas) and highly preferable to OCGT (imported gas) and is reassigned a preference score of 77.5, with OCGT (imported gas) reassigned a score of 87.5.

Storage based hydro and pumped hydro with an initial preference score of 65 are compared and considering the marginally higher costs of pumped hydro, storage based hydro is reassigned a score of 62.5 while pumped storage hydro is reassigned a score of 67.5.

Sub-attribute –CAPEX

Weightage: 5.91

Main Attribute: Economy

	T1	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**	**T8**	**T9**	**T10**	**T11**	**T12**	**T13**	**T14**	**T15**	**T16**
T1	50	50	65	65	65	65	82.5	82.5	65	27.5	27.5	42.5	42.5	60	65	67.5

The preference score for "CAPEX" is evaluated based on the expected range of capital costs of the concerned technology expressed in Rs. per MW. Comparison of technologies for this sub-attribute is done on the basis of quantitative data for CAPEX. CAPEX of technologies is independent of the resource.

Based on the sub-attribute matrix in Chapter 4, supercritical CFBC and Ultra supercritical PCand UCG with a CAOEX range of Rs 70—75 Million/MW are assessed to be moderately less preferable to supercritical technology and are assigned a score of 65. IGCC with significantly more CAPEX outlay as compared to supercritical PC technology is assessed to be highly less preferable and is assigned a preference score of 82.5. OCGT and CCGT technologies with significantly lower CAPEX are assigned an initial score of 35 while hydro technologies are assessed to have moderately higher CAPEX requirements and also assigned a preference score of 65.

In the next step, considering the high difference between the costs of OCGT and CCGT, the scores of OCGT technologies are reassigned as 27.5, while those of CCGT technologies are reassigned to 42.5. Among hydro technologies, CAPEX for RoR are assessed to be moderately lower than those of storage based hydro, while the CAPEX of pumped hydro are assessed to be marginally more than RoR. Based on this assessment, RoR is reassigned a score of 60, while pumped storage is reassigned a score of 67.5.

Sub attribute –OPEX

Weightage: 6.13

Main Attribute: Economy

	T1	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**	**T8**	**T9**	**T10**	**T11**	**T12**	**T13**	**T14**	**T15**	**T16**
T1	50	50	52.5	52.5	50	50	65	65	65	52.5	52.5	52.5	52.5	47.5	50	52.5

The preference score for "OPEX" is evaluated based on the expected range of variable costs of the concerned technology expressed in Rs. per MW. Comparison of technologies for this sub-attribute is done on the basis of quantitative data for OPEX. As the OPEX is resource independent, the same preference score is assigned to a particular technology.

Supercritical PC, Ultra supercritical PC, and storage based hydro have the same OPEX of approximately Rs 1.5 Million/ MW/Year and are assigned a preference score of 50. Supercritical CFBC, OCGT, CCGT and pumpedstorage hydro is estimated to have OPEX of approximately Rs 1.75 Million/ MW/ Year i.e. marginally higher OPEX as compared to supercritical PC and therefore the preference value of 52.5 is assigned to these technologies. IGCC and UCG, with estimated OPEX costs of 2.5 Million/ MW, are assessed to be moderately less preferable and are reassigned a score of 65. RoR is assessed to have marginally lower OPEX costs as compared to supercritical PC technology and is assigned a score of 47.5. Pumped storage based is assessed to have marginally higher OPEX costs than storage based units and is reassigned a score of 52.5

Sub-attribute – Technology Maturity
Weightage: 6.82
Main Attribute: Technology

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	50	70	70	65	60	87.5	77.5	77.5	50	50	50	50	50	50	52.5

The preference score for "technology maturity" is evaluated based on the current state of readiness of the technology in terms of its commercial availability. Comparison of technologies for this sub-attribute is done on the basis of qualitative facts available. For the purpose of comparison the present level of maturity, level of indigenization, and number of plants currently installed are also considered.

Technologies like supercritical PC, OCGT, CCGT, RoR and storage based hydro are assessed to be mature and are assigned a score of 50. Pumped hydro storage is assessed to be only slightly less mature, considering the operational experience-especially in India, and is assigned a preference score of 52.5.

Supercritical CFBC and Ultrasupercritical PC, relatively new technologies, are assessed to be moderately less preferable and are assigned an initial preference score of 65. In contrast, considering the limited number of plants and lack of operational expertise, IGCC and UCG are assessed to be highly less preferable and are assigned an initial preference score of 82.5.

In the next step, supercritical CFBC and Ultrasupercritical PC technologies, with an initial score of 65, are compared to assess their relative preferences. Ultrasupercritical technology (imported coal) is assessed to be highly preferable to supercritical CFBC considering its operational record and is reassigned a preference score of 60, while CFBC technologies are reassigned a score of 70.

Sub-attribute – Net Efficiency
Weightage: 7.05
Main Attribute: Technology

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	47.5	50	47.5	42.5	40	50	47.5	30	50	50	27.5	27.5	12.5	12.5	22.5

The preference score for "net efficiency" is evaluated based on the ratio of useful electricity output and total energy input (thermal + auxiliary energy) if any. Comparison of technologies under this sub attribute is done on the basis of quantitative data available for the expected efficiency of each technology.

As the assessment is resource independent, the net efficiencies of combustion technologies are assessed with conversion efficiency of hydro technologies. Net efficiency of supercritical PC, supercritical CFBC, and IGCC with domestic coal and OCGT with domestic gas/international gas is assessed to be approximately around 37% and these technologies are considered equally preferable and are assigned a preference score of 50. Supercritical PC, supercritical CFBC, and IGCC with imported coal with an efficiency figure of approximately 38% are assessed to be marginally superior and are assigned a preference score of 47.5.

Ultra supercritical PC with domestic coal (38-40%)/international coal (41%), UCG (47-54%) and CCGT (54-56%) are assessed to be moderately preferable to supercritical PC (domestic coal) and are assigned an initial preference score of35. Hydro based technologies with a net conversion efficiency of over 90% are assessed to be highly preferable to the reference technology and are assigned an initial score of 17.5.

In the next step, Ultrasupercritical PC, UCG and CCGT, with an initial score of 35, are compared to assess their relative preferences. Considering the significantly higher net efficiencies of CCGT (54-56%) as compared to Ultrasupercritical technology (38-41%), CCGT technologies are reassigned a score of 27.5 while Ultrasupercritical technology is reassigned a score of 42.5. To factor in the difference between Ultrasupercritical PC based on domestic an imported coal, Ultrasupercritical imported coal based technology is reassigned a value of 40. Considering the marginal difference in the net efficiency of UCG as compared to CCGT, UCH is reassigned a preference score of 30. All hydro technologies with an initial score of 17.5 are assessed. Considering the lower net efficiency of pumped hydro storage as compared to RoR and storage based hydro, pumped storage is assessed to be highly less preferable and is reassigned a score of 22.5, while RoR and storage are reassigned a score of 12.5.

Sub-attribute – Fuel Flexibility
Weightage: 4.78
Main Attribute: Technology

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	50	17.5	17.5	50	50	50	50	50	50	50	50	50	50	50	50

The preference score for “fuel flexibility” is evaluated based on theability of a technology to work with varying levels of fuel mix. Comparison of technologies under this sub attribute is done based on the qualitative facts available. Supercritical CFBC boilers accommodate the maximum range of fuel variations among the fleet of technologies. Therefore, supercriticalCFBC can be considered highly preferable as compared to the reference technology.

Supercritical PC, Ultra supercritical PC, and all hydro technologies are not meant for fuel flexible operation. Therefore they are considered to be equally preferable. IGCC, UCG, OCGT and CCGT are considered to be slightly moreflexible than supercritical PC as syngas can be fired in gas based power plants and gas can be fired in UCG and IGCC based plants. Therefore these technologies are marginally preferable over supercritical (domestic coal)

Sub-attribute –Infrastructure
Weightage: 5.77
Main Attribute: Infrastructure

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	60	50	60	50	60	50	60	35	52.5	70	52.5	70	30	35	40

The preference score for “infrastructure” is evaluated based on thebuilt Physical Infrastructure: requirement of additional investments for rails, road, ports, etc. Comparison of technologies is done based on the qualitative data available. Technologies based on domestic fuel have almost the same infrastructure requirements. Supercritical PC, Supercritical CFBC, ultra supercritical PC, IGCC with domestic coal, all require the same infrastructure like rail, road, water infrastructure etc. For OCGT and CCGT based on domestic gas, requirement of large pipeline networks suggests almost the same infrastructure requirements. Based on this assessment, domestic gas based technologies are assigned a preference score of 50.

Similarly Supercritical PC, Supercritical CFBC, ultra supercritical PC, IGCC with imported coal, OCGT and CCGT with imported gas all may have a similar extent of infrastructure requirements like ports, rail and road to power plant (for imported coal), regasification plants and pipeline infrastructure (for imported LNG). Therefore initially a preference score of 65 is assigned to all these technologies. UCG requires moderately low additional infrastructure since no coal mining or transportation are involved. Therefore it is assessed to be moderately preferable to the reference technology and is assigned a score of 35.

For hydro technologies, it is assessed that the requirements of a single point and single location civil infrastructure for a large hydro plant will be moderately less compared to those of domestic coal based technologies, Based on this assessment, all hydro technologies are assigned an initial score of 35. Considering the moderately lower requirements of RoR and moderately higher infrastructure requirements of pumped hydro (tail pond reservoir), RoR is reassigned a score of 30 while pumped storage hydro is reassigned a score of 40.

In the next step, imported coal based technologies and imported gas based technologies with preference scores of 65 are compared to reassign preferences. It is assessed that OCGT, CCGT with imported gas would have larger infrastructure requirements (dedicated LNG Ports and pipelines) than technologies based on imported coal. Therefore, imported coal based capacities are assessed to be moderately preferable to imported gas based technologies and are reassigned a preference score of 60. Imported gas based technologies are reassigned a score of 70.

Sub-attribute – Resource Risk (Price)
Weightage: 4.55
Main Attribute: Policy Risks

	T1	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**	**T8**	**T9**	**T10**	**T11**	**T12**	**T13**	**T14**	**T15**	**T16**
T1	50	77.5	50	77.5	50	77.5	50	77.5	50	50	87.5	50	87.5	50	50	50

The preference score for "Resource risk (price)" is evaluated based on thepotential for risks arising from non-control over international coal and LNG prices, and risks arising from losing regulatory control over electricity costs due to pass through of fuel costs. The main difference is between the resource types. All domestic resources are assessed to have equal risks, while imported resources are assessed to have different risks depending on the resource type.

Based on sub-attribute matrix in Chapter 4, it is assessed that imported gas (LNG) and imported coal have very high risks of import prices and are therefore assigned an initial preference score of 87.5. All other technologies including hydro are assessed to be equally preferable and are assigned a score of 50 – the same as the reference technology.

In the next step, it is assessed that imported coal based technologies are highly preferable to imported gas based technologies and are therefore reassigned a score of 77.5. Imported gas based technologies are reassigned a score of 87.5.

Sub-attribute – Resource Risk (Availability)
Weightage: 5.83
Main Attribute: Policy Risks

	T1	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**	**T8**	**T9**	**T10**	**T11**	**T12**	**T13**	**T14**	**T15**	**T16**
T1	50	65	50	65	50	65	50	65	50	50	82.5	50	82.5	50	50	50

The preference score for "Resource risk (availability)" is evaluated based on thepotential for risks arising from international policy changes, non access to transport routes, resource nationalistic polices by exporting countries, disruption of supply chain, resource capturing, etc. Technologies using the same resource (domestic or imported) are assessed to have the same risk potential. All domestic resources are assessed to have equal risks, while imported resources are assessed to have different risks depending on the resource type.

Based on sub-attribute matrix in Chapter 4, it is assessed that the availability risk of gas is very high as compared to the availability risks of coal as coal resources can be procured from multiple locations while gas resources are limited mainly to the Gulf nations. Considering this, imported gas based technologies are assessed to have highest risks and are therefore assigned a preference score of 82.5. Imported coals based technologies, on the other hand, are assessed to have moderately higher risks as compared to domestic coal based technologies and are assigned a preference score of 65.

Sub-attribute – FE risks
Weightage: 3.94
Main Attribute: Policy Risks

	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16
T1	50	77.5	50	77.5	50	77.5	50	77.5	50	60	87.5	70	87.5	17.5	17.5	17.5

The preference score for "FE risks" is evaluated based on the potential for impact of technology on foreign exchange reserves exposure. Impacts of technologies as well as resources are considered in the assessment.

Domestic coal based Supercritical, Ultrasupercritical IGCC, and UCG are assessed to have equal technology import risks and are assigned a preference score of 50. Imported coal based supercritical, Ultrasupercritical IGCC are assessed to have similar technology import exposure but are assessed to have higher resource import exposure and are assigned an initial value of 82.5.

Domestic gas based technologies are assessed to have higher technology import exposure as compared to domestic coal based technologies and are assigned an initial preference score of 65. Imported gas based technologies are assessed to have a significantly higher impact and are assigned a score of 82.5. Hydro technologies are assessed to be highly preferable to domestic coal based technologies as they are assessed to have very low technology import exposure as compared to domestic coal based technologies. All hydro technologies are assigned a score of 17.5.

In the next step, imported coal based technologies and imported gas based technologies, with scores of 82.5 are compared to assess relative preferences. Considering the high technology and resource prices of imported gas, it is assessed to be highly not preferable to imported coal based technologies and is reassigned a preference score of 87.5. All imported coal based technologies are reassigned a score of 77.5. OCGT (domestic gas) is assessed to be highly preferable to CCGT (Domestic gas) considering lower costs and technology dependence. OCGT (Domestic gas) is thereby assigned a score of 60, while CCGT (domestic gas) is reassigned a score of 70.

Final Scores

Using the weightages (given in chapter 3 of main report) for each sub-attribute, the final score of the technology is calculated using equation 1 as illustrated in the methodology. The weighted average of each sub attribute is shown in table 2 and table 3.

Table 2 Consolidated scores of technologies

Sub-attributes	**T1**	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**	**T8**	**T9**	**T10**	**T11**	**T12**	**T13**	**T14**	**T15**	**T16**	**Weights**
GHG emissions	50	42.5	47.5	42.5	42.5	40	42.5	40	30	40	40	17.5	17.5	5	5	5	**9.3**
Air Pollution (SPM, SOx, NOx)	50	50	22.5	22.5	47.5	47.5	35	35	12.5	15	15	12.5	12.5	5	5	5	**5.7**
Water use & Pollution	50	42.5	50	42.5	47.5	40	35	27.5	27.5	12.5	12.5	22.5	22.5	5	5	5	**5.8**
Land Diversion and Land Use	50	27.5	52.5	27.5	42.5	27.5	50	27.5	12.5	17.5	12.5	22.5	17.5	35	47.5	47.5	**3.7**
Loss of Biodiversity	50	20	50	20	50	20	50	20	35	35	15	35	15	65	82.5	82.5	**4.2**
Public Health	50	35	50	35	50	35	35	22.5	12.5	17.5	17.5	17.5	17.5	5	5	5	**5.6**
Displacement Potential	50	37.5	50	37.5	50	37.5	50	37.5	30	32.5	30	32.5	30	65	82.5	82.5	**4.3**
Employment Generation	50	65	50	65	50	65	50	62.5	62.5	67.5	70	65	67.5	65	62.5	62.5	**3.1**
Cost of Generation	50	60	50	60	50	60	70	70	60	77.5	87.5	70	82.5	52.5	62.5	67.5	**7.6**
CAPEX	50	50	65	65	65	65	82.5	82.5	65	27.5	27.5	42.5	42.5	60	65	67.5	**5.9**
OPEX	50	50	52.5	52.5	50	50	65	65	65	52.5	52.5	52.5	52.5	47.5	50	52.5	**6.1**
Technology Maturity	50	50	70	70	65	60	87.5	77.5	77.5	50	50	50	50	50	50	52.5	**6.8**
Net Efficiency	50	47.5	50	47.5	42.5	40	50	47.5	30	50	50	27.5	27.5	12.5	12.5	22.5	**7**
Fuel Flexibility	50	50	17.5	17.5	50	50	50	50	50	50	50	50	50	50	50	50	**4.8**
Infrastructure	50	60	50	60	50	60	50	60	35	50	70	50	70	30	35	40	**5.8**
Resource Risk (Price)	50	77.5	50	77.5	50	77.5	50	77.5	50	50	87.5	50	87.5	50	50	50	**4.6**
Resource Risk (Availability)	50	65	50	65	50	65	50	65	50	50	82.5	50	82.5	50	50	50	**5.8**
Macro-economic risks	50	77.5	50	77.5	50	77.5	50	77.5	50	60	87.5	70	87.5	17.5	17.5	17.5	**3.9**
TOTAL SCORES	50	50.24	49.13	49.51	50.12	50.76	53.64	52.96	42.27	42.34	47.89	39.93	45.27	34.88	38.25	40.09	**100**

The final score obtained is used to derive the first priority order of the technologies. The technology with the lowest score becomes the most preferredchoice in the priority list and the technology with the highest score becomes the least preferred choice in the priority order

Based on this methodology and scoring process the first order priority is shown in table 3 below

Table 3 Final Technology Scores

Scores	**Rank**	**Technology Priorities**
34.88	1	Run of River Hydro
38.25	2	Storage based hydro
39.92	3	CCGT (Domestic gas)
40.09	4	Pumped Hydro
42.26	5	Underground Coal Gasification (UCG)
42.34	6	OCGT (Domestic Gas)
45.27	7	CCGT(Imported gas)
47.89	8	OCGT (Imported Gas)
49.13	9	CFBC Supercritical (Domestic Coal)
49.50	10	CFBC Supercritical (Imported Coal)
50	11	PC Supercritical (Domestic Coal)
50.11	12	PC Ultra Supercritical (Domestic Coal)
50.23	13	PC Supercritical (Imported Coal)
50.75	14	PC Ultra Supercritical (Imported Coal)
52.96	15	IGCC (Imported Coal)
53.64	16	IGCC (Domestic coal)

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ANNEXE 4

HYDROPOWER RESOURCES AND TECHNOLOGIES-FOR TRANSITION

Annexe 4
Hydropower Resources and Technologies – for Transition

Hydropower is a proven, mature, predictable and cost competitive technology. Hydropower projects are usually designed to suit particular needs and specific site conditions, and are classified by project type, head (i.e., the vertical height of water above the turbine) or purpose (single- or multi-purpose). Size categories (installed capacity) are based on national definitions and differ worldwide due to varying policies. In India, hydropower schemes up to 25 MW station capacities are classified as Small Hydropower and considered as renewable sources of energy.

Hydropower plants offer a number of advantages over their thermal and nuclear counterparts. Firstly, they need no fuel. Secondly, their efficiency is very high, generally ranging between 85-90%. Thirdly, the hydropower plants offer remarkable flexibility of operation: a running turbo-generator can increase its power output almost instantaneously whereas its startup takes only 1-2 minutes. Variation in load /demand has very little effect on the economical operation of the hydropower plant. Fourth, hydroelectricity is not subject to price changes once the plant is constructed, as there are no varying fuel costs.

With a very large reservoir (or very consistent river flows), HEPs can generate power at a near constant level throughout the year (i.e., operate as a base-load plant). Alternatively, in the case that the hydropower capacity exceeds the amount of available storage, the hydropower plant is referred to as energy-limited. In this case, the use of reservoir storage allows hydropower generation to occur at times that are most valuable from the perspective of the power system rather than at times dictated solely by river flows. Even with sufficient storage, hydropower generation may still be limited by downstream flow constraints such as irrigation, recreation, etc.

Hydropower plants also offer operating flexibility in that they can start generating electricity with very short notice and low start-up costs, provide rapid changes in generation and have a wide range of generation levels over which power can be generated efficiently (i.e. high part-load efficiency) . The ability to rapidly change output in response to system needs makes hydropower plants well suited for providing the balancing services like regulation and load-following. RoR HEPs operated in cascades in unison with an upstream storage hydropower can also provide significant benefits, as the flow releases can be timed with the system needs. Pumped storage hydro plants can be established specifically to meet the peak load as well as the balancing / spinning requirements.

Hydropower plants come in three main project types: Run-of-river (RoR), Storage hydro and Pumped storage hydro. A brief description of each of these configurations is presented below

1. **Run of river hydropower**: As per the CEA, Run-of-River schemes are schemes that either have sufficient pondage to meet the diurnal variation of the power demand or have no upstream pondage (i.e. all the incoming water is fed into the turbine at the same time). (Ref: Best Practices and Benchmarks in Hydro Power Projects, CEA, Chapter 2, Page 21)
   RoR hydropower projects have small intake basins with limited or no storage capacity. Power production therefore is dependent on the hydrological cycle of the watershed. For RoR HEPs, the generation varies as water availability changes, and thus they may be operated

as variable power plants in small streams or as base-load power plants in large rivers. Large scale RoR HEPs may have some limited ability to regulate water flow, and if they operate in cascades in unison with storage hydropower in upstream reaches, they can contribute to the overall regulation and balancing ability. Most of the RoR plants with pondage have limited storage capabilities (daily, maximum weekly).

2. **Storage Hydropower:** As per the CEA, these are the schemes that have a reservoir with a large storage capacity to store excess water in the monsoon months and to generate power in non-monsoon months. (Ref: Best Practices and Benchmarks in Hydro Power Projects, CEA, Chapter 2, Page 22)
   Hydropower projects with a reservoir are called storage hydropower since they store water for later consumption. The reservoir reduces the dependence on the variability of inflow. The generating stations are located at the dam toe or further downstream, connected to the reservoir through tunnels or pipelines. *Hydropower projects with a reservoir (storage hydropower) deliver a broad range of energy servic*es as base load**,** peak load or as general system regulators by providing frequency or voltage support services. In addition, they often deliver services that go beyond the energy sector, including flood control, water supply, navigation, tourism and irrigation.

3. **Pumped storage Hydropower:** As per the CEA, pumped storage schemes have two reservoirs, upper & lower. Water flows from the upper reservoir to the lower for generation during peak hours and vice versa for pumping back water during off-peak hours. (Ref: Best Practices and Benchmarks in Hydro Power Projects, CEA, Chapter 2, Page 22)
   Pumped storage plants are not energy sources, but are instead storage devices. In such a system, water is pumped from a lower reservoir into an upper reservoir, usually during off-peak hours, while flow is reversed to generate electricity during the daily peak load period or at other times of need. Although the losses of the pumping process make such a plant a net energy consumer overall, the plant is able to provide large-scale energy storage system benefits. By reversing the flow of water, electrical energy can be produced on demand, with a very fast response time. Pumped hydropower storage plants can also use the output from thermal plants during low load times. The hydraulic, mechanical and electrical efficiencies of pumped storage determine the overall cycle efficiency, which ranges from 65% to 80%**.**
4. **Future Hydropower Technologies:** A fourth category, in-stream (hydrokinetic) technology, which utilizes ultra low head (< 3m) to generate power, is less mature and functions more like a Run of River hydro turbine without any regulation.

A4.1. Hydro Turbine technology

The net head available to a hydro turbine dictates the turbine technology for a particular site. The flow rate considered for the plant dictates its capacity. Hydro turbines come in two basic configurations: impulse turbines and reaction turbines. The turbine configurations are based on the manner in which the water causes the turbine runner to rotate.

Impulse Turbines

An impulse (Pelton) turbine has one or more free jets discharging directly to impact the buckets of the turbine runner. The impulse turbine exhibits high efficiency of over 90% (Ref: Page 8, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011). Single nozzle turbines typically have a very flat efficiency curve and could work with relatively high efficiency at close to 20% of rated capacity (Ref: Page 8, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011). For multi-nozzle units, the range is broader because the number of operating jets can be varied.

Maintenance costs for an impulse turbine are less than for a reaction turbine as they are free of cavitation problems. Excessive silt or sand in the water, however, will cause more wear and tear on the runner of an impulse turbine as compared to the runner of most reaction turbines.

A cross flow turbine is an impulse type turbine with partial air admission. Performance characteristics are similar to an impulse turbine. This turbine also has a relatively flat efficiency curve over a wide range of flow and head conditions. Maximum efficiency of this type of turbine is about 60-65%. (Ref: Page 17, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011)

Reaction Turbines

Reaction turbines operate with their runners fully flooded. The reaction of the water pressure on the runner blades produces a torque, unlike in the case of impulse turbines, which operate in the air and convert the energy of water pressure into kinetic energy. Reaction turbines are classified as Francis (mixed flow) or axial flow. Axial flow turbines are available with both fixed blades (Propeller) and variable pitch blades (Kaplan). Both axial (Propeller & Kaplan) and Francis turbines may be mounted either horizontally or vertically. The peak efficiency of a Francis turbine is assessed to be 93-94% (Ref: Page 5, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011).

A Francis turbine runner has fixed blades (vanes), usually nine or more, and the water enters the turbine in a radial direction, and is discharged in an axial direction. A Francis turbine may be operated over a range of flows approximately 40 to 110% of the rated discharge. However, operating below 40% of the rated discharge can cause vibration problems and power surges. (Ref: Page 5, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011)

The graph below is a standard load efficiency curve for hydro turbines. It can be observed that the drop in the efficiency of Francis turbines is steeper when operated below 40% of the rated capacity.

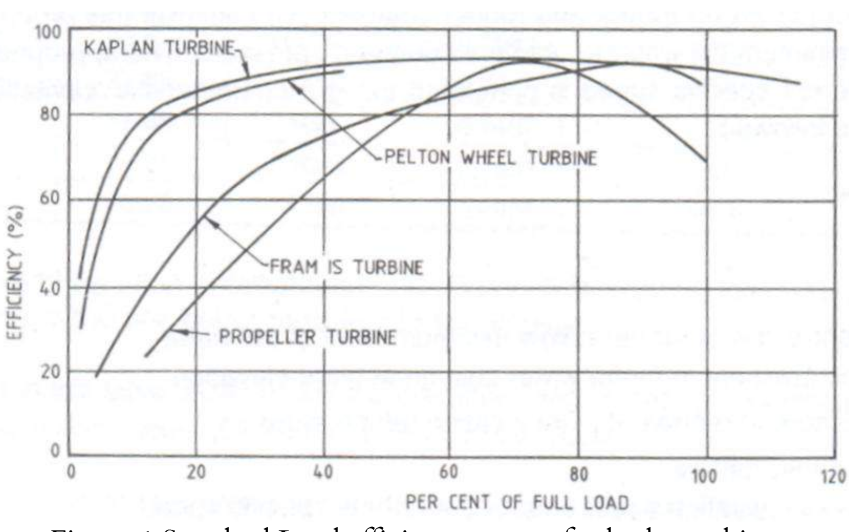

Figure 1 Standard Load efficiency curves for hydro turbines

Impulse turbines have highest efficiency at low loads as compared to reaction turbines; the advantage of Kaplan turbines is they exhibit high efficiency from 30-100% of the rated capacity.

A4.1.1. Selection of Hydro Turbines

Turbines are selected based on head available in the location. The criteria for a unit vary based on its utility. Base load plants can have high water conductor lengths between reservoir and tail race. Peak load plants, however, require small L/H ratios (Length to Head ratio) for faster response times.

Flow rate determines the capacity. In reaction turbines, efficiency increases as the size or throat diameter increases and they have a slower response time to varying load requirements as compared to impulse turbines as they are limited by the design flow rate of water in the penstock. Impulse turbines have an application in high head low flow conditions and are more amenable to quick load changes.
Civil construction costs could be typically higher in case of reaction turbines (Ref: Page 6, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011). Francis turbines are efficient across varying head flow but their operating range is 40/60% to 100% (Ref: Page 5, Guidelines for Selection of Turbine and Governing System for Hydroelectric Projects, AHEC, April 2011). On the other hand, axial flow turbines exhibit a wide range of operation and can virtually start from zero loads.

The selection procedure for turbines should consider the utilization factor of location and the utility of the plant (for peaking or base load). Impulse turbines are better suited for cycling operations. Reaction turbines, on the other hand, provide maximum output for the rated capacity and are better suited for varying heads. Turbines used for peaking purposes exhibit ramp rates of 4-6% per second. In low head units, the L/H ratio will determine the ramp rates, in most cases longer design lengths lead to slower response times of the units. The mechanical limitations for turbine response time are higher than the rates mentioned above, however, flow limitations in the penstock limit the response time of these units.

Another determining factor for the selection of turbines is the number of turbines to be used for a plant. Efficiencies of larger units are higher than those of smaller units of the same type. For a given plant capacity, total cost of the power plant will increase if, the numbers of units are increased. If discharge is uniform or slightly fluctuating, large turbine units are the preferred option so as to reduce cost and avail of the maximum output benefits. A very large discharge variation resulting in large variations in power generation may require a larger number of small units in order to retain high efficiency.

When there is variable demand, it is preferable to have smaller sized turbines to handle the variations better.

In the case of pumped storage, the sizes of the upper and lower reservoirs are dependent on the head available and the capacity of the plant. Both upper and lower reservoirs have usually enough storage to provide full capacity power for about 6 to 8 hours. Some pumped storages could be designed for more than 20 hours of storage and it may vary according to site characteristics. Indian reservoir plants, where some units have been operating in pumped mode, have not been in operation because of the delay in the construction of the tail pool race dam. The lower reservoir is constructed by building a dam across a small stream.

For pumped storage, use of adjustable speed units helps to manage the speed of the pump according to the prevailing head and the required output. The principle behind adjustable speed was the development of a two speed synchronous motor-generator.

Francis turbines are commonly used in modern power Pumped Storage power plants. In conventional units, the single speed reversible pump turbine is designed for operating at constant speed along the fixed curve in the Head vs Discharge curve for the pump. The positioning of wicket gates in conventional systems is such that the changes in pumping speed are the least. In adjustable speed turbines the operating range along the Head vs. Discharge curve is extended because alternating power input allows the pump to reduce power inputs at lower heads, avoiding reverse flow in high head low speed operation by adjusting the pumping power through better frequency control.

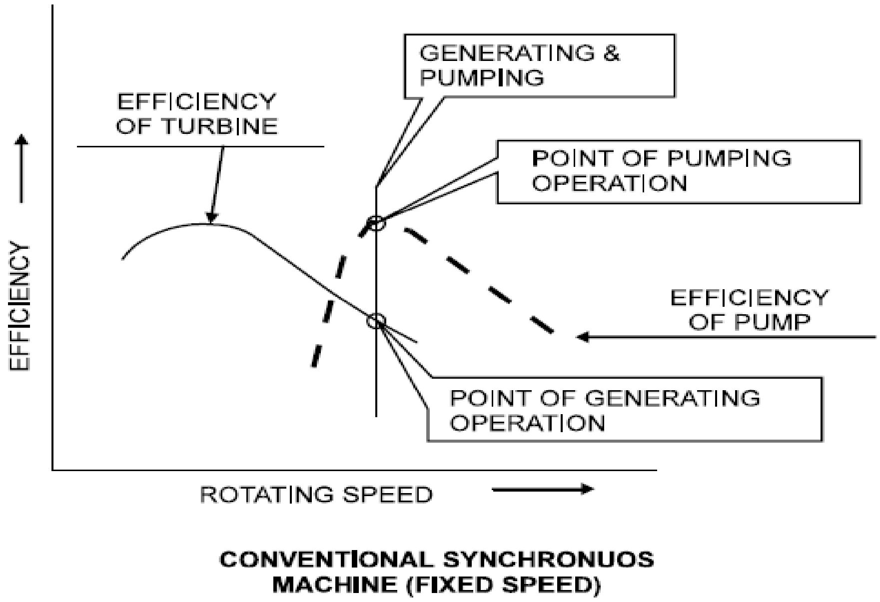

Figure 2 Conventional units Efficiency vs. Rotating sped

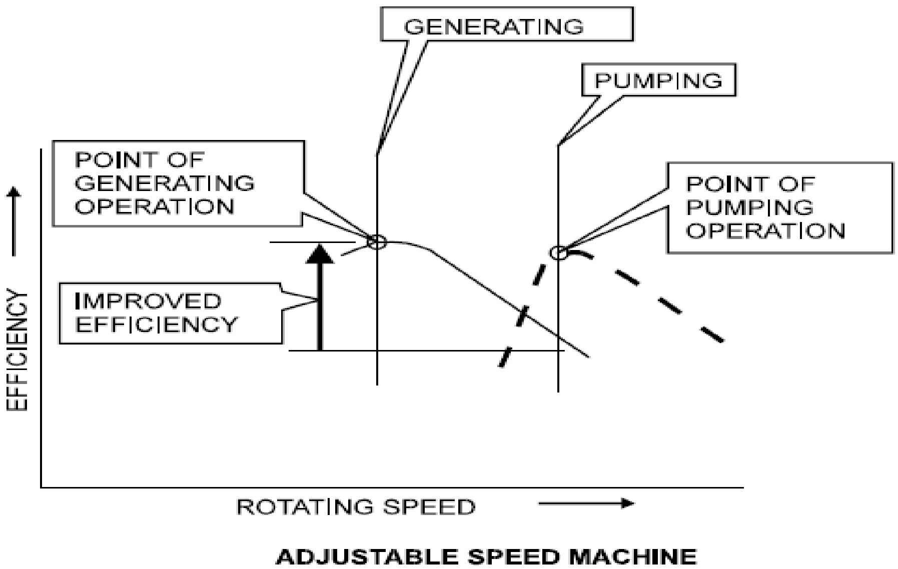

Figure 3 Adjustable units Efficiency vs. Rotating sped

Source: Technical Analysis of Pumped storage and Integration with Wind power in the Pacific Northwest, By MWH, Aug 2009, Page A-12.

Conventional units are designed to operate at the highest efficiency in one of the operating modes (pumping or turbine operation modes), as shown in the figure 2 above. In case of adjustable units the highest efficiency points can be achieved in both modes giving it the advantage of higher output and low input power (for pumping mode) which is shown in figure 3.

Case Study: Pumped storage Hydro -Gravity Power Module (GPM)

[Ref: http://www.gravitypower.net/Technology.aspx]

The technology in this case is developed by Gravity Power to be utilized as pumped storage hydro.

The GPM uses a very large piston that is suspended in a deep, water-filled shaft, with sliding seals to prevent leakage around the piston and a return pipe connecting to a pump-turbine at ground level. The piston is made of reinforced rock and, in some cases concrete. The shaft is filled with water at the start of operations and is then sealed. As the piston drops, it forces water down the storage shaft, up the return pipe and through the turbine, and spins a motor/generator to produce electricity. To store energy, grid power drives the motor/generator in reverse, driving the pump to force water down the return pipe and into the shaft, pushing up the piston to its original location. Figure 4 shows the diagram of the system

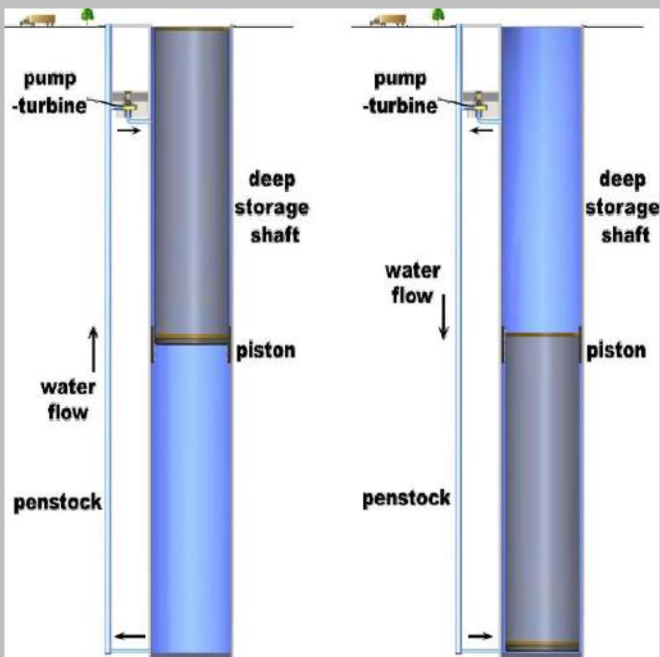

Figure **4** Storage Hydro System (Gravity Power concept)

According to the technology developers, large MW size storage capacities can be built using this technology. The storage efficiency is also high as pump-turbines have low losses and friction is negligible at modest piston speeds.

A4.2. Cost trends for hydropower technologies

Hydropower is often economically competitive with current market energy prices, though the cost of developing, deploying and operating new hydropower projects will vary from project to project. Hydropower projects often require a high initial investment, but have the advantage of very low O&M costs and a long lifespan.

Investment costs for hydropower include costs of planning; licensing; plant construction; impact reductions for fish and wildlife, recreational, historical and archaeological sites; and water quality monitoring. Overall, there are two major cost components: the civil construction costs, which normally are the greatest costs of the hydropower project; and electromechanical equipment costs. The civil construction costs follow the price trends in the country where the project is going to be developed. In the case of developing countries, the costs are likely to be relatively low due to the use of local labor and local materials. The costs of electromechanical equipment follow the trend of prices at a global level.

In hydropower projects where the installed capacity is less than 5 MW, the electromechanical equipment costs tend to dominate. As the capacity increases, the costs are increasingly influenced by the cost of civil structures. The components of the construction project that impact the civil construction costs most are dams, intakes, hydraulic pressure conduits (tunnels and penstocks) and power stations; therefore, these elements have to be optimized carefully during the engineering design stage. Specific investment costs (per installed kW) tend to be reduced for a higher head and higher installed capacity of the project. With higher head, the hydropower project can be set up to use less volume flow, and therefore smaller hydraulic conduits or passages. The size of the power equipment is also smaller and related costs are lower. Table 1 collates cost related information of different hydro projects from various studies

Table 1 Cost ranges for Hydropower – Summary of main cost parameters from 10 studies

Source	Investment Cost (IC) (USD $_{2005}$ /kW)	O & M Cost (% of IC)	Capacity Factor (%)	Lifetime (Years)	Discount rate (%)	LCOE (cents/ kWh)	Comments
Hall et al. 2003 *Ref: Hall et al. (2003)*	< 500 - 6,200; Median 1,650; 90% below 3,250		41 - 61				2,155 Projects in USA 43,000 MW in total Annual Capacity factor (except Rhode Island)
VLEEM - 2003 *Ref: Lako et al. (2003)*	< 500 - 4,500; Median 1,000; 90% below 1,700		55 - 60				250 projects for commissioning 2002 - 2020 Total capacity 202,000 MW Worldwide but mostly Asia and Europe
WEA 2004 *Ref: UNDP/UNDESA/WEC (2004)*	1,000 - 3,500; 700 - 8,000		35 - 60; 20 - 90			2 – 10; 2- 12	Large Hydro; Small Hydro (<10MW) (Not explicitly Stated as levelized cost in report)
IEA-WEO 2008 *Ref: IEA (2008a)*	2,184	2.5	45	40	10	7.1	
IEA-ETP 2008 *Ref: IEA (2008b)*	1,000 - 5,500; 2,500 - 7,000	2.2 - 3			10; 10	3 – 12; 5.6 -14	Large Hydro; Small Hydro
EREC/Greenpeace *Ref: Teske et al. (2010)*	2,880 in 2010	4	45	40	10	10.4	

Source	Investment Cost (IC) (USD $_{2005}$ /kW)	O & M Cost (% of IC)	Capacity Factor (%)	Lifetime (Years)	Discount rate (%)	LCOE (cents/ kWh)	Comments
BMU Lead study 2008 *Ref: BMU (2008)*	2,440				6	7.3	Study applies to Germany only
Krewitt et al 2009 *Ref: Krewitt et al. (2009)*	1,000 - 5,500	4	33	30		9.8	Indicative average LCOE year 2000
IEA – 2010 *Ref: IEA (2010b)*	750 - 19,000 in 2010 (1,278 average)		51	80; 80		2.3-45.9; 4.8	Range for 13 projects from 0.3 to 18,000 MW; Weighted average for all projects
REN21 *Ref: REN21 (2010)*						5 – 12; 3 – 5; 5 - 40	Small Hydro (<10MW); Large Hydro (>10MW); Off-Grid (<1MW)

Source: Special Report on RE sources &climate change mitigation, IPCC

Out of the ten important international studies quoted above, the VLEEM-2003 (Very Long Term Energy-Environment Model) was an EU-funded project executed by a number of research institutions in France, Germany, Austria and the Netherlands. The study analyses 250 hydropower projects worldwide with a total capacity of 202,000 MW, with the most in-depth focus on Asia and Western Europe. The projects were planned for commissioning between 2002 and 2020. As per the VLEEM 2003 study, the investment cost of large hydro projects ranges between 1000 USD_{2005} and 4500 USD_{2005} per KW (INR 44million – 198 million/MW), with the median falling at USD_{2005} 1000/KW (INR 44 million/MW), and 90% of the projects have investment cost below USD_{2005} 1700 /KW (INR 74 million/MW) .

The above study predicts that for an average capacity utilization factor (CUF) of 44% and investment costs between USD_{2005} 1,000/kW (INR 44 Million/MW) and USD_{2005} 3,000/kW (132 million/MW) , the levelized cost of electricity (LCOE) ranges from US $cent_{2005}$ 2.5/kWh (INR 1.10/kWh) to US $cent_{2005}$ 7.5/kWh (INR 3.30/kWh). Most of the projects developed in the near-term future (up to 2020) are expected to have investment costs and LCOE in this range. Under favorable conditions, the LCOE of hydropower can be in the range of US cent $_{2005}$ 3/kWh (INR 1.32/kWh) to US cent $_{2005}$ 5/kWh (INR 2.20/kWh).

The actual data by and large substantiate the results of the VLEEM-2003 study, which predicted the investment cost and levelized cost of electricity of HEPS to be commissioned during year 2002-2020: USD_{2005} 1,000/KW INR 44 Million/MW) and USD_{2005} 3,000/KW (132 million/MW), the levelized cost of electricity LCOE ranges from US $cent_{2005}$ 2.5/kWh (INR 1.10/kWh) to US $cent_{2005}$ 7.5/kWh (INR 3.30/Kwh).

Once built and put in to operation, hydropower plants usually require very little maintenance and operation costs can be kept low, since hydropower plants do not have recurring fuel costs. O&M costs are usually given as a percentage of investment cost per kW. A typical average O&M cost for hydropower is 2.5% per KW of investment cost.

A4.3. Hydro Power Potential

A systematic survey of hydro power potential in India was first undertaken during the period 1953 to 1959 by the erstwhile Central Water and Power Commission. According to this survey, hydro power potential of the country was assessed to be about 42,000 MW from a total of 250 schemes. This survey provided the base for development of hydro power projects in the country

for the next two decades.
The basin wise potential of India (shown in Table 2 below) as per the reassessment study of 1978-87 carried out by CEA is given below. It can be seen that the Ganga and Brahmaputra form the major share of potential in the country.

Table 2 Basin wise Hydro Potential

(Ref: http://www.cea.nic.in/reports/hydro/ranking_study/gen_report.pdf)

All India Level Basin wise Hydro Potential		
River Basin	**No. of Identified schemes**	**Installation Potential (MW)**
Indus	190	33382
Brahmaputra	226	66065
Ganga	142	20711
Central Indian River System	53	4152
West Flowing Rivers of Southern India	94	9430
East flowing Rivers of Southern India	140	14511
All India (Total)	845	148701

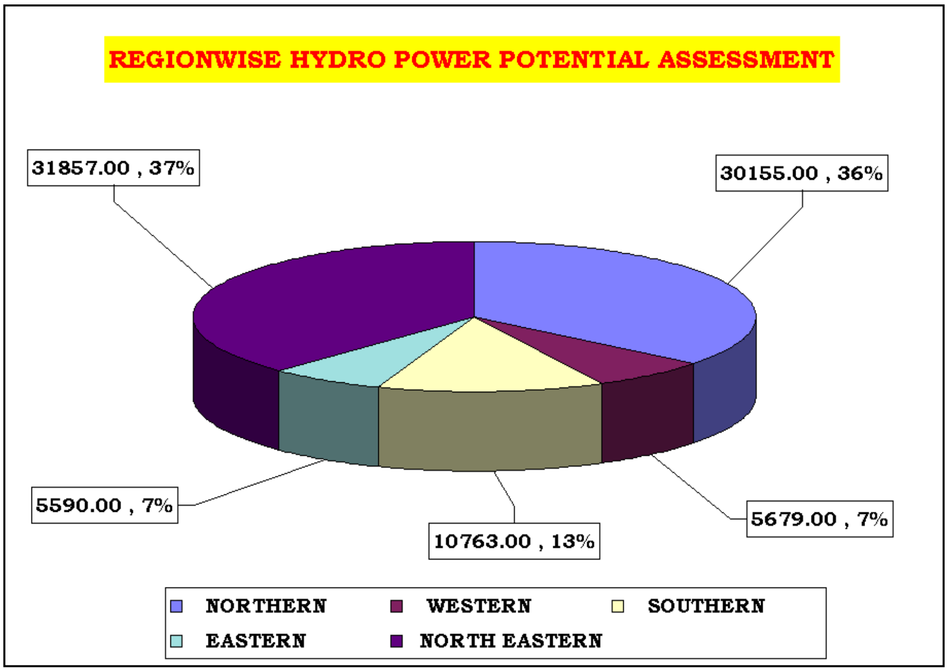

Figure 5 Regional distribution of Hydro Potential

Source: Hydro development plan for 12th five year plan (2012-2017) – CEA Report

The Region-wise potential assessment (shown in figure 5 above) for hydro power development for the 12th five year plan reveals that the majority (73% combined) is in the North and North-Eastern part of India.

Reassessment studies carried out by the CEA during 1978-87 identified 63 sites for pumped storage plants (PSP) with total installation capacity of about 96,524 MW with individual capacities varying from 600 MW to 2800 MW. Reassessment studies carried out by the CEA during 1978-87 identified 63 sites for pumped storage plants (PSP) with total installation capacity of about 96,500 MW with individual capacities varying from 600 MW to 2800 MW. Out of these, 7 Pumped Storage Plants with an installation capacity of 2604 MW were under operation

/construction at the time of the re-assessment study. The region wise / state wise distribution of potential sites identified for installation of pumped storage schemes is given below in table 3.

Table **3** Region wise Potential of Pumped Storage

SL	**Region / State**	**Identified Potential (MW)**
	Northern	13065
	Western	39684
	Southern	17750
	Eastern	9125
	NE Region	16900
	Total	**96524**

Source: Large Scale Integration of Renewable Energy Sources – way forward, CEA, Nov 2013

A4.3.1. Ranking study by the CEA

To give the necessary fillip for the development of the balance hydroelectric schemes and with a view to prioritize the large number of identified schemes to harness vast untapped hydro resources in the order of their attractiveness for implementation, ranking studies were carried out by CEA in October, 2001. **[Ref: http://www.cea.nic.in/reports/hydro/ranking_study/ gen_report.pdf]** The Ranking Study gives inter-se prioritization of the projects which could be considered for further implementation including their survey & investigation so that hydro power development is effected in an appropriate sequence. Table 4 below shows the potential for hydro development as identified by the Planning Commission in the 12th five year plan.

Table **4** PFR studies (Schemes identified with low tariff (< INR 2.50/kWh))

SN	**State**	**No of schemes**	**Potential (MW)**
1	Arunachal Pradesh	19	21800
2	Himachal Pradesh	11	2860
3	J&K	05	1715
4	Karnataka	04	1600
5	Meghalaya	07	651
6	Sikkim	04	835
7	Uttaranchal	28	4559
	Total	78	34020

Source: Hydro development plan for 12th five year plan (2012-2017) – CEA Report

At present 9 pumped storage schemes with aggregate installed capacity of 4785.6 MW are in operation in the country. Out of these, only 5 plants with aggregate installed capacity of 2600 MW are being operated in the pumping mode. The details of these 9 plants are given in the table 5 below.

Table 5 Status of installed pumped storage plants

[**Ref:** Large Scale Integration of Renewable Energy Sources – way forward, CEA, November 2013]

S. No.	Name of Project / State	Installed Capacity		Pumping mode Operation	Reasons for not working in pumping mode
		No. of Units	Total MW		
1	Kadana St. I&II, Gujarat	2x60+2 x60	240	Not working	Due to vibration problem
2	NagarjunaSagar, Andhra Pradesh	7x100.8 0	705.6	Not working	Tail pool dam under construction
3	Kadamparai, Tamil Nadu	4x100	400	working	-
4	Panchet Hill - DVC	1x40	40	Working	Tail pool dam not constructed
5	Bhira, Maharashtra	1x150	150	Working	-
6	Srisailam LBPH, Andhra Pradsesh	6x150	900	Working	-
7	Sardar Sarovar, Gujarat	6x200	1200	Not working	Tail pool dam not constructed
8	Purlia PSS, West Bengal	4x225	900	Working	-
9	Ghatgar Maharashtra	2x125	250	Working	-
		Total	**4785.6**		

Two pumped storage plants are under construction in the country, further, 3 pumped storage plants with aggregate installed capacity of 2100 MW are under Survey & Investigation in the country. The Tehri PSS (4*250) has been delayed due to a combination of social, geological and technical issues owing to lack of preparedness from the developer. *(Ref: Large Scale Integration of Renewable Energy Sources – way forward, CEA, Nov 2013; Status of Hydro Electric Projects under execution, 201, CEA)*

A4.4. Environmental and Social Impacts of hydropower

Hydroelectric power projects affect a river's ecology, mainly by inducing a change in its hydrological characteristics and by disrupting the ecological continuity of sediment transport and fish migration through the building of dams, dikes and weirs. However, the extent to which a river's physical, chemical, biological and ecosystem characteristics are modified depends largely on the type of HEP.

The creation of a reservoir for storage hydropower entails a major environmental change by transforming a fast-running river ecosystem into a still-standing artificial lake.

Similar to a hydropower project's ecological effects, the extent of its social impacts on the local and regional communities, land use, economy, health and safety or heritage varies according to project type and site-specific conditions. While Run of river projects generally create relatively little social impact, the storage type HEP in a densely populated area can entail significant challenges related to resettlement and impacts on the livelihoods of the downstream populations and the risks of a disaster in the form of a dam burst.

HEPs can also have positive impacts on the living conditions of local communities and the regional economy, not only by generating electricity but also by facilitating, through the creation of freshwater storage schemes, multiple other water-dependent activities, such as irrigation, navigation, tourism, fisheries or sufficient water supply to municipalities and industries while protecting against floods and droughts. One of hydropower's main environmental advantages is that it creates no atmospheric pollutants or waste associated with fuel combustion. However, all freshwater systems, whether they are natural or man-made, emit GHGs (e.g., CO2, methane) due to decomposing organic material.

However, life Cycle Assessments that evaluate GHG emissions of HEPs during construction, operation and maintenance, and dismantling, show that the majority of lifecycle GHG emission estimates for hydropower cluster between about 4 and 14 g CO2eq/kWh, but under certain scenarios there is potential to emit much larger quantities of GHGs. *(Ref: Renewable Energy Sources and Climate Change Mitigation, 2012, IPCC)*. While some natural water bodies and freshwater reservoirs may even absorb more GHGs than they emit, there is a definite need to properly assess the net change in GHG emissions induced by the creation of such reservoirs.

Note: Work in environmental and social impact assessment and mitigation

In November 2000, a report on 'Dams and Development' was released by the World Commission on Dams, (WCD).

The WCD designed a framework for selection of hydro power projects while considering the interests of all the stakeholders involved in the project. The framework emphasizes gaining public acceptance and inclusion of the local public in the decision making process for the implementing a project. This process increases the social value of the project and enhances its chances of a successful implementation. Involving independent agencies to provide critical reviews on impact of the projects on the local habitat will provide transparency to the decision making process. Establishment of independent committees for reviewing current procedures for shared rivers will create clear decision making criteria for projects. Ensuring compliance of the framework requires a monitoring agency which includes social and environmental perspectives in its assessment.

The WCD has identified five key decision points for hydro projects. Figure 6 is a flowchart of the decision points. These points are not exhaustive and involve many other aspects (for e.g. negotiations with the local population and agreements reached) that need to be interpreted and implemented in planning individual projects.

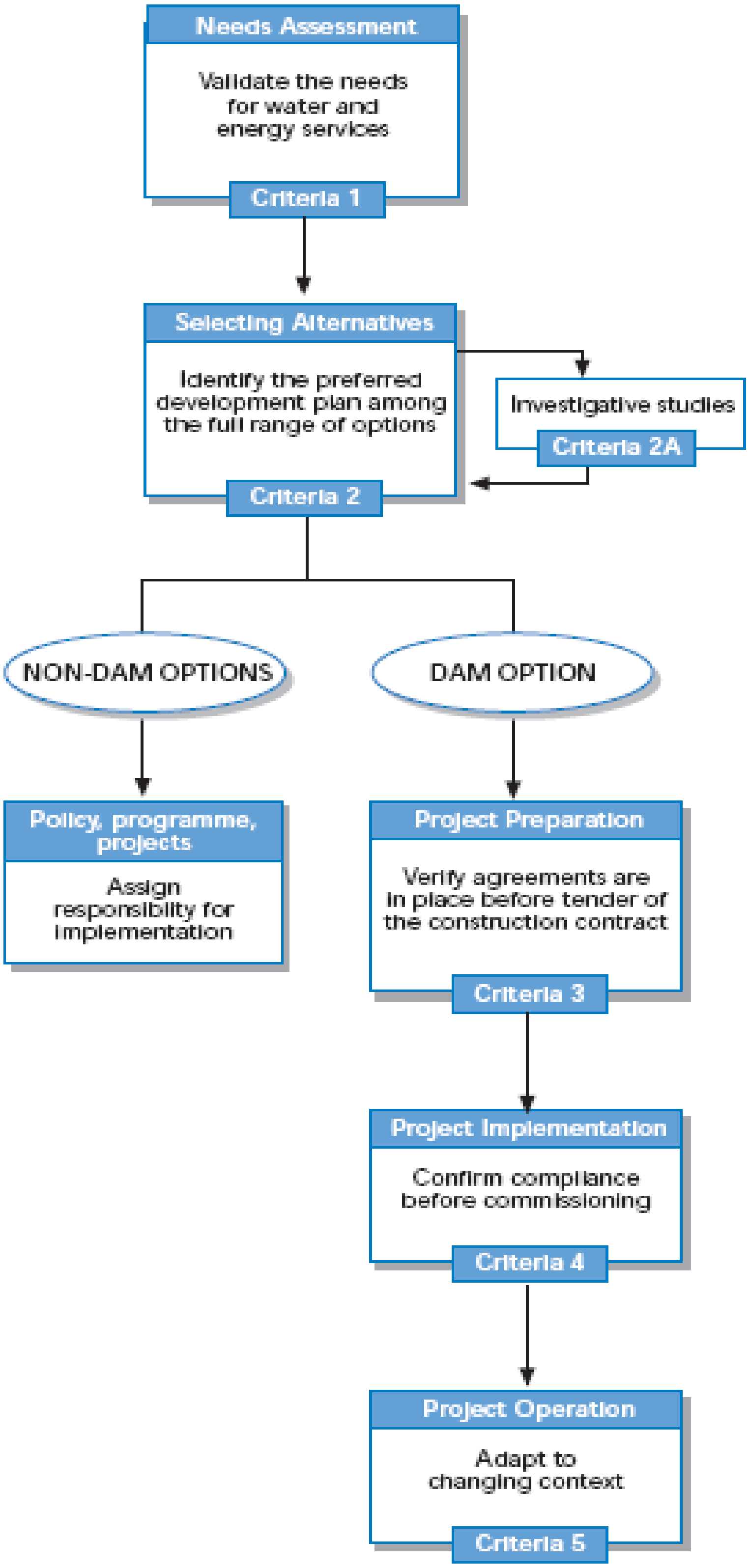

Figure 6 Five key decision points in planning and project development (Ref: Dams and Development, WCD, November 2000, Page 263)

In addition to this, substantial work has also been done in understanding the impacts of downstream river flows on ecology and society. The major damage caused by a hydro project is altering the natural course of a river. Excerpts from a SANDRP study highlight the following ecological impacts:

(1)Altering flows can lead to severely modified channel and floodplain habitats, because river flow shapes physical habitats such as riffles, pools, and bars in rivers and floodplains, and thereby determines biotic composition;

(2) Aquatic species have evolved life history strategies such as their timing of reproduction in direct response to natural flow regimes, which can be desynchronized through flow alteration;

(3) Many species are highly dependent upon hydraulic connectivity, both lateral and longitudinal, which can be broken through flow alteration; and

(4) The invasion of exotic and introduced species in river systems can be facilitated by flow alteration.

(Ref: Towards Restoring Flows into the Earth's Arteries: A PRIMER ON ENVIRONMENTAL FLOWS by Latha Anantha, River Research Centre; & Parineeta Dandekar, South Asia Network on Dams Rivers and People.)

If we look at related policies, it appears that while the National Water Policy 2012 states "Water is essential for sustenance of eco-system, and therefore, minimum ecological needs should be given due consideration", specific prioritization of allocations for ecological needs is not identified in the policy. The policy sticks to the word 'minimum' in this regard, where specificity would have brought tougher measures.

Based on the statistical analysis of hydrological data of a few Himalayan and Peninsular rivers by the National Institute of Hydrology (NIH), Roorkee, and the CWC, Hyderabad (Report of the working group constituted by the MoEF and Ministry of Water Resources, (MWR)), the following stipulations were suggested for environmental flows:

Himalayan Rivers

- *Minimum flow not to be less than 2.5% of 75% dependable Annual Flow expressed in cubic meters per second.*
- *One flushing flow during the monsoon with a peak not less than 250% of 75% dependable Annual Flow expressed in cubic meters per second.*

Other Rivers

- *Minimum flow in any ten daily periods to be not less than observed in ten daily flows with 99% exceedance. Where ten daily flow data is not available this may be taken as 0.5% of 75% dependable Annual Flow expressed in cubic meters per second.*
- *One flushing flow during monsoon with a peak not less than 600% of 75% dependable Annual Flow expressed in cubic meters per second.*

All this suggests that although there is a clear acknowledgement of the environmental and social effects of hydro power across both the divided parties (hydro developers and protestors), there are still contentious issues related to the extent of acceptable damage and the associated limits that have to be put in place. However, considering the site-specific nature of hydro projects, a consensus on these limits will need a completely different approach to project appraisal and planning.

Conclusion

Hydro power generation is the most reliable and clean source of energy available amongst the technologies considered in this study. Reservoir based hydro plants have the advantage of storing water longer than pumped and RoR. It is this advantage that will be useful in long term cycling requirements from the grid. The importance of pumped units in current energy scenario must not be undermined, considering the peak requirements of power.

There is no dearth of potential for hydro and the economic implications of hydro also seem to be moderate. However, large-scale hydro development cannot be done in a business as usual mode. The project development methodology and, more importantly, the approach to new hydro power development has to change and become more inclusive.

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The World Institute of Sustainable Energy (WISE) is a not-for-profit institute established in 2004 in Pune, India, committed to the cause of promoting sustainable energy and sustainable development, with specific emphasis on issues related to renewable energy, energy security, energy efficiency, and climate change.

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