BEFORE THE NATIONAL GREEN TRIBUNAL
AT NEW DELHI

ORIGINAL APPLICATION NO. 221 OF 2016

IN THE MATTER OF:

DEBADITYO SINHA & ANR…. ….. …. ….. …… … ……**APPLICANTS**

Versus

MINISTRY OF ENVIRONMENT, FORESTS

AND CLIMATE CHANGE & ORS… …. …. …. …. …**RESPONDENTS**

CONSOLIDATED REJOINDER TO THE REPLY FILED BY THE RESPONDENTS

It is most respectfully submitted:

1. That the Applicants are filing a consolidated rejoinder to the replies filed by the respondents in the matter. At the outset, the Applicants deny each and every statement, allegation, averment and contention made by the said Respondents in their reply affidavits which is contrary to or inconsistent with what is stated in the application. The Applicants pray that nothing should be deemed to be admitted by the Applicants by virtue of not having been specifically denied herein.

2. It is submitted that this application has been filed by the applicants herein seeking appropriate directions from this Hon'ble Tribunal for prevention, control and abatement of environmental pollution caused by the thermal power plants across the country. The applicants have contended that the existing framework adopted for regulating the operations of the thermal power projects are highly inadequate and deficient in dealing with the environmental pollution. Thus, unless effective measures are implemented, the existing problem of pollution by the thermal power plants which is constantly on the rise cannot be controlled. It is submitted that out of 20 most polluted cities in the world, 13 are in India. It is established fact that the thermal power plants are one of the significant contributor of PM, SO2, NOx, Secondary Particles, Heavy Metals among other toxic gases. The applicants have therefore challenged the

Notification dated 07.12.2015 since the standards of emission prescribed by the MoEF are inadequate to tackle with the existing problem of pollution which has become critical in our country and have also suggested effective measures which may be kept in consideration by the Hon'ble Tribunal while dealing with the critical issue of environmental pollution caused by the thermal industry.

3. That the applicants wish to submit that the reply of Respondent No.1 (MoEFCC) and Respondent No. 2 (Central Pollution Control Board) is moreover the same with only few exceptions. There are several issues which were raised particularly with respect to Respondent No. 1 which have not been responded. The Respondent No.3 (Ministry of Power) has taken different perspective and in some places has contradicted with the submissions made by other Respondents. The Respondent No. 4 (Ministry of Water Resources, River Development and Ganga Rejuvenation) has not filed any reply though the application had raised issues on water abstraction from thermal power plants and the impacts on river basins. The Respondent No.4 has submitted to the Hon'ble Tribunal that it has preferred to adopt the reply filed by Respondent No.1.

4. That the applicants are filing a combined response to all the respondents in the paragraphs mentioned below:

5. **Impact on Human Health**: That the Respondent No.1 (para 6.1 at pg 216) and Respondent No.2 (para 13 at pg 241) in its counter has not considered all the researches which have been presented by the applicants in order to establish that the emissions from the thermal power plants are responsible for causing massive impact on human health and consequently lead to deaths of people affected by it. The respondents have rather responded to only one research paper and have completely ignored the comprehensive studies filed by the applicants. The applicants want to reiterate the facts and submissions made at para 6.1 in the original application and the same are not reproduced here for the sake of brevity. Further, the contention of the Respondent No. 3

(Para 6.1 at pg 269) that the impact of the project is limited to its surroundings is liable to be rejected because the impacts of thermal power emissions are not limited only to its surrounding but are carried to long distances as up to 400 Km due to tall stacks and dispersal by wind. This fact has been also highlighted in the paper published by IIT Delhi annexed as Annexure A-4 to the original application. To establish the gravity of the problem-as a case study, the applicants wish to produce an excerpt from IIT Kanpur's Report on Delhi's air pollution titled 'Comprehensive Study on Air Pollution and Green House Gases (GHGs) in Delhi' prepared for Govt. of NCT of Delhi and Delhi Pollution Control Cell in January, 2016 which is as follows:

> '*There are 13 thermal power plants (TPP) with a capacity of over 11000 MW in the radius of 300km of Delhi, which are expected to contribute to secondary particles. Based on the study done by Quazi (2013), it was shown that power plants contribute nearly 80% of sulfates and 50% nitrates to the receptor concentration. A calculation assuming 90% reduction in SO2 from these plants can reduce 72% of sulphates……. Similarly, 90% reduction in NOx can reduce the nitrates by 45%.*'

Copy of the relevant excerpts from the report 'Comprehensive Study on Air Pollution and Green House Gases (GHGs) in Delhi' 2016, by IIT Kanpur is annexed herewith as **Annexure A-1**.

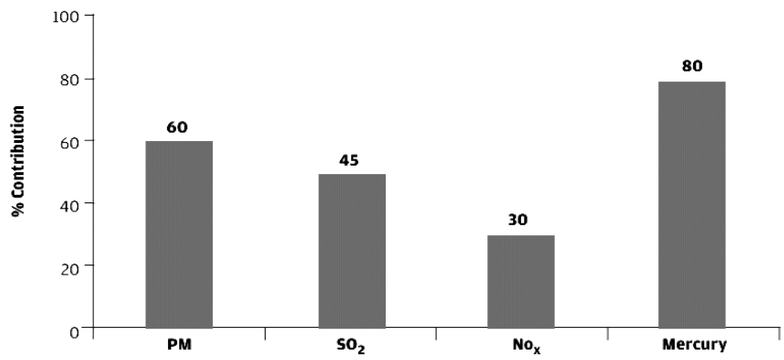
6. **Impact on Agriculture:** That the Respondent No 1 in para 6.2 **(**Pg 217**)** and Respondent No**.** 2 in para 14 **(**Pg 242**)** of their respective replies have stated**:**

> ***'****It may be true that overall production of wheat and other crops has been reduced due to change in weather pattern and the climate change in last decade but it cannot be attributed to emissions from thermal power plants only****.'***

The applicants submit that it is true that the impacts may not only be due to thermal power plants, but that admits that thermal power plants have contributed in part in producing those impacts**.** As emissions from thermal

power plants are a significant major source of SOx, NOx and secondary particulate matters, their contribution to the existing air pollution problem cannot be ignored. As per 'Proceedings and Recommendations of the Stakeholder Workshop' published by Centre for Science and Environment in September 2016': The thermal power plants are responsible for 60% of PM, 45% of SO_2, 30% of NOx and 80% of Mercury in India-thus making it a major contributor to the air pollution problem. A graphical representation from the report is shown below.

Graph 1: **Contribution of coal-based power sector to industrial emissions**



Source: Centre for Science and Environment, 2014–15

Copy of the report titled 'Proceedings and Recommendations of the Stakeholder Workshop' published by Centre for Science and Environment in September 2016 is annexed herewith as **Annexure A-2.**

7. **Controlling Particulate Matter:** That the Respondent No.1 at para 6.8,6.9 (Pg 219) and Respondent No. 2 at para 20 (Pg 244) of their respective replies have admitted that the older units are inefficient contributing higher emissions as these have outlived. However, the respondents submit that to control the pollution by these older units, ESP's have been provided and emission limits of particulate matter has been made more stringent. The respondents have referred to the same emission standards which is being disputed in the present case. It is submitted that prescription of inadequate emission standards will not be of any help. The applicants have stated in the original application that the ESP's can only control PM emissions but are not adequate enough to

control the emissions of toxic gases and heavy metals**.** The applicants wish to reiterate the submissions made in para 6**.**10 of the original application**.**

8. The Respondent No.1 at para 6.10.1 (Pg 220) and Respondent No.2 at para 22 (Pg 245) in their respective replies have submitted that the main hindrance is space constraint and limitation to install high efficiency ESPs. In response to the same, the applicants wish to produce the relevant extract from the Proceedings of the CSE Workshop provided at Annexure A-2 which has given a solution to this issue. The same is reproduced herein:

> *"a) Units commissioned between 1990 and 2008 (43.0 GW total capacity) may need to upgrade the ESP to meet the PM norms of 100 and 50 mg/Nm3. In some cases, it may involve adding fields in series or parallel or increasing the height of ESP. The cost of these renovations would be around Rs 15 lakh/MW.*
>
> *b) Most units installed after 2008 (109.4 GW capacity) were required to meet PM norms of 50 mg/Nm3 by the environment clearances. Therefore, a basic performance revamp may suffice for these units. However, some units were required to meet 100–150 mg/Nm3 and others are poorly performing—an investment of at most Rs. 10 lakh/MW may be required for these units.*
>
> *c) Units in pipeline should be able to meet the 30 mg/Nm^3 PM standard with a combination of ESP and FGD. In fact, an integrated design would mean that the ESP size can be made smaller than a standalone one for meeting the norm".*

Contrary to the replies of the Respondent 1 and 2 which have focussed on space constraint as the main hindrance, CSE policy brief has shown that with modification and upgradation of technology in the existing units, the emissions can be controlled. However, this may require further investments.

9. **Controlling SO_2 and Installation of Flue Gas Desulphurisation (FGD) System:** On the issue of relaxation to older and smaller units, the Respondent

No. 2 in para 22 (Pg 245) of the reply has stated that these units do not have space for installation of FGD while units with capacity of 500 MW and above have been asked to keep space for installation of FGD, if required in future. The said respondent has further taken an exception to the matter that the plants with less capacity installed between 2003-2016 shall be required to meet the emission limit of 600 mg/Nm3 and no relaxation has been granted to these plants. However, the Respondent No. 2 and Respondent No.3 at Para 6.7 (Pg 278), have admitted that the emission limits for SO_2 cannot be achieved in new and existing plants without installation of FGD.

10. The applicants wish to refer to their submission made at para 6.7 and 6.8 of original application to substantiate their concern that the smaller and older units (less than 500 MW) are most polluting and they need to be scrapped immediately. It is humbly submitted that whatever standard is prescribed, unless advanced technologies like Flue Gas Desulphurization is used, there will not be any significant reduction in SO2 levels. The applicants further deny the submissions made by Respondent No.3 in Para 6.7 (Pg 278, 279) that the dispersal through tall stack will reduce the SO2 emission and the installation of FGD may not be insisted upon where the National Ambient Air Quality Standards are already being met by the power stations, and are being monitored by pollution control authorities like SPCB/CPCB. It is submitted that the emission of SO_2 from a coal based thermal power plant cannot be denied and if some power plant is reporting emissions within the national standards without any additional measures, then it must be thoroughly investigated instead of relying blindly on the data provided. Additionally, this kind of practice must be discouraged as they provide room for manipulation of emission data. The applicants in response of the concern raised by Respondent No.3 about disposal of Gypsum submits that FGD-Gypsum is used world over in producing wallboards, concrete for highways, bridges, buildings, and many other structures. Further, FGD gypsum, if properly managed, can be an important potential input into agricultural systems. However, that will require the

government to prescribe standards and specifications before putting them into use. The applicants wish to produce certain reports and research papers as an evidence to their claim annexed herewith as **Annexure A- 3 (Colly)**.

11. The applicants further submit that air pollution equipment like FGD and SCR have many co-benefits. The SO_2 and NOx emitted from the thermal power plants also contribute to formation of Secondary Particulate Matters in the atmosphere as a result of secondary reactions and this further cause harmful impact on air quality. Thus, installation of FGD and SCR will also be helpful in controlling Particulate Matter in ambient air. Further the installation of FGD has many other benefits like improving efficiency of existing ESPs and most importantly its capacity to trap Mercury and other heavy metals. The applicants wish to reiterate their submission made at para 6.7 of original application.

12. That the applicants submit that given the air pollution and its serious effects on public health which is being faced by the country today, no further risks should be allowed in cases where the cause of such risk is already known. For those units where FGD cannot be installed due to 'space constraint', the applicants in the original application has already suggested measures for the same. The applicants have submitted that the 'older new' units which do not have space allocations for FGDs must be mandated to go for 'desulphurization of coal' before combustion and adopt other in-combustion methods. The older units where it is impossible to bring down the emission levels of SO_2, must be decommissioned and upgraded to latest technology units

13. **Control of Mercury and other Heavy Metals:** That the Respondent No**.** 1 at para 6**.**3 **(**Pg 217**)** and Respondent No**.** 2 at para 15 **(**Pg 242**)** in their replies have stated**:**

> '…*It is admitted that thermal power plants do emit heavy metals including mercury. In order to reduce mercury emission from thermal power plants, new limit of mercury emission (0.03 mg/Nm3) have been notified vide Notification, dated 07.12.2015'*

Further the Respondent No.1 at para 6.10.1 (Pg 221) and Respondent No. 2 at para 22 (Pg 246) of their replies has stated:

> '*It is submitted that data collected from Indian thermal power plants is not sufficient to decide the definite levels of emissions using Indian as well as imported coal. Besides, there is no data available to assess levels of mercury in ambient air. Considering these constraints and emission limits notified by the most of the countries (China, Germany, USA, etc.) the present limits of mercury were notified*.'

The reply of Respondent No. 1 and 2 is vague and based on mere assumptions and must be outrightly rejected by the Hon'ble Tribunal. The case of the applicant is that the standards prescribed for Mercury are 73 times weaker than US EPA and will be ineffective in reducing the existing emissions of Mercury by thermal power plants. Given the fact that Mercury is hazardous for the environment and human health, we cannot afford any relaxation of its emission and should not find excuses for not prescribing the same. India is the second biggest emitter of Mercury from thermal power plants. The applicants wish to reiterate the submissions made in original application at para 6.3 to highlight the health and ecological impact of mercury pollution from thermal power plants which is well established through data and case studies. It is further submitted that contrary to the vague claims made by Respondent No.1 and Respondent No.2, the Respondent No.3 in its reply at Para 6.3 (Pg 270) has produced data on mercury emissions from the Central Institute of Mining and Fuel Research (CSIR-CIMFR) study. As per the study referred to by R-3, the total mercury emission from coal fired power plants in the year 2008 was 38.54 MT/annum when there were no standards prescribed. The same study showed emissions from flue gas of Talchar NTPC, Korba West and Budge Budge Thermal Power Plants at outlet of ESP as 14.84, 11.50 and 4.24 ug/Nm^3. It is to be noted that this figure in ug/Nm^3 produced herein by R-3 is noted when the flu gas is treated only by ESP and the same figures when converted to mg/Nm3 comes out to be 0.015 mg/Nm3, 0.01 mg/Nm3 and

0.004 mg/Nm3 whereas the emission limit prescribed by R-1 is 0.03 mg/Nm3. Thus, it gives sufficient indication that the present emission limit of Mercury prescribed is much higher compared to what the thermal power plants are presently emitting-thus the emission level prescribed will be of no help in reducing the present levels of Mercury emissions from thermal power plants. Therefore, the emission limits prescribed for Mercury by R-1 is nothing but a lip service. The applicants further wish to refer to the reply of R-3 at para 6.10 (Pg 283) where it is stated:

> *'However, the emission of mercury shall get reduced with the installation of other polluting controlling equipment like FGD, SCR and ESP etc. Globally, control of mercury is achieved by co-benefits of SOx and NOx control equipment. With the proposed new regulation of MOEF, the mercury emission levels shall be met by co-benefit from these systems.'*

Para 9 of the reply of R-3 (Pg 287) further states,

> '*All the above norms require installation of FGD system. Installation is feasible in plants where space provision has been kept for FGD. As per new regulations installation of FGD and SCR would be required in all new thermal power plants and also in existing thermal power stations*.'

It is submitted that the reply of R-3 not only contradicts with the replies of R-1 and R-2 but it further complements the applicants' contention that FGD and SCR is necessary for reduction of mercury in emissions. Thus, it is amply clear that FGD and SCR is a necessity and the MOEFCC/CPCB cannot provide any excuses for not mandating the same for all coal based thermal power plants and consider the best standards as US EPA for prescribing emission standard for Mercury.

14. **Control of NOx:** That the reasons provided by R-1 at para 6.10.1 (Pg 221) and R-2 at para 22 (Pg 246) in their replies are vague and without any scientific justification. The contention of the Respondents that there will be reduction in emissions because now emission standards have been prescribed which were not existing earlier is baseless. The respondents have failed to give any proper justification to the contention made by the applicants that the limits prescribed for older units is highly relaxed and will not be adequate enough to control the emissions. Contrary to the submissions of R-1 and R-2, R-3 at para 6.10 (Pg 283) and para 9 (Pg 288) has admitted that Selective Catalyst Reduction (SCR) technology would be required for reduction in NOx levels. However, the said respondent has also submitted that for NOx control, there is no proven and established control technology suited for our high ash Indian coal and for that purpose, studies may be required. The applicants wish to submit that SCR has proved to be an appropriate technology for reduction of NOx levels even in context of thermal power plants in India. It is submitted that SCR units are now indigenously manufactured in India. As per a presentation of government owned company Bharat Heavy Electrical Limited (BHEL) dated 22.04.2016, they have already developed and tested a SCR technology for Indian power plants which showed better NOx reduction efficiency (90%) as compared to imported catalyst. The BHEL presentation on the same is uploaded on website of 'Excellence Enhancement Centre (EEC) for Indian Power Sector' and relevant slides are annexed herewith as **Annexure A-4**. It is to be noted that EEC was set up through an Implementation Agreement between Ministry of Power, Govt. of India and GIZ, Germany under the Indo German Energy Programme in September, 2011.

15. **Water Consumption Limit:** That the replies by R-1 at para 6.10.1 (Pg 221) and R-2 at para 22 (Pg 246) is vague and fails to respond to the submissions made in the Original Application. However, the Respondent No.2 in its reply at para 18 (Pg 243) has admitted that the water consumption is higher in India. Contrary to the submissions made by Respondent No 1 and Respondent No

2, the Respondent No 3 Ministry of Power has stated that the Central Electricity Authority **(**CEA**)** guidelines are based on Indian operating conditions and are considered appropriate**.** The applicants wish to highlight the following reply of Respondent No**.**3 on this aspect**. (**para 6**.**10 at pg 284**):**

> *'The conversion of Once Through Cooling (OTC) System to Cooling Tower (CT) based system is a difficult proposition in view of the extra space required for installation of additional system. The norm of 2.5 m3/MWh is difficult to achieve if water required for FGD is also taken into consideration. In Indian conditions, consumptive water requirement at 2.5 m3/MWh without FGD and 2.8-3.0 m3/MWh with FGD is considered the best achievable.'*

The applicants wish to submit that the difficulty to replace once through cooling with cooling tower based system should not be a matter of consideration now, as the notification dated 07.12.2015 has prescribed that all plants with OTC shall install CT within 2 years. The critical issue raised by the applicants is that the standards for water consumption after installation of CT is relaxed and must be made stringent. In fact, the standards prescribed for water consumption after conversion from OTC to CT (ie 3.5 m3/MWh) in the notification dated 07.12.2015 is much relaxed than what Respondent No.3 has stated in their reply (ie 2.8-3.0 m3/MWh). In addition to the above facts, the applicants submit that Respondent No.3 in its reply (Para 6.6 at pg 278) has mentioned about a Tariff Policy notified on 28.01.2016 related to recycling of waste water but have not provided copy of the same. The applicants request that the copy of the Tariff Policy shall be provided by R-3 for perusal of the applicants and this Hon'ble Tribunal.

The applicants wish to refer to their original submission at para 6.10.1 (v) at Pg 42 wherein the applicants have suggested for zero liquid discharge to be mandated in all thermal power plants and making 2m3/MWh as the uniform standard as the same is the best standard water consumption achieved in India till now.

16. **No standards for other Hazardous pollutants:** That the R-1 and R-2 at para 6.10.2 (Pg 222) and para 23 (Pg 246) of their respective para states the following reason for not prescribing emission standards for other hazardous chemicals:

> '*..it is to be submitted that even developed countries like USA, EU, Japan including China have not notified emission limits of trace elements as these pollutants gets reduced after application of other technologies like FGD for control of emission of* SO_2.'

This submission by the said respondents has been made assuming that all such hazardous chemicals mentioned by the applicants like Lead, Selenium, Arsenic, Beryllium, Cadmium, Chromium, Cobalt, Manganese, Acid Gases, Polycyclic Aromatic Hydrocarbons, Volatile Organic Compounds, Dioxins and Furans will be controlled after installation of FGD. The Respondents have categorically admitted here that these pollutants can be controlled by application of FGD's. It is therefore, abundantly clear that installation of FGD in all thermal power plants is a necessary requirement and must be prescribed by the Respondent No.1.

17. **No standards for Radioactivity of Fly Ash**: That in response to the contention made by the applicants that no standards for radioactivity in thermal power plants has been prescribed in the notification despite the judgment of this Hon'ble Tribunal in the matter of Krishi Vigyan Arogya Sansthan vs MoEF and Ors, the Respondent No.1 in para 6.10.2 (iv) (Pg 222) has remain silent and has referred to only two studies of the thermal power projects situated in Delhi wherein the level of radon and natural radioactivity content is under safe limit. The said contention is baseless and does not absolve the Ministry from its responsibility of prescribing the permissible levels of nuclear radiation and complying with the judgment of the Hon'ble Tribunal. Further, assessment of radioactivity levels in only two thermal power projects does not imply that the levels of radioactivity in all the remaining projects of the country are within limits.

18. **Installation of Ultra-Super-Critical Systems instead of Super Critical in Upcoming Power Plants**: That the reply of R-3 at para 6.8 (Pg 280) shows that the government is committed to phase out sub-critical units and replacing it by more efficient super-critical units and several steps are taken to facilitate the process. Similar argument is taken by R-1 and R-2 as well. The applicants wish to reproduce the submission made by R-3 in its reply at para 6.10 (ii) (Pg 285):

> '*The issue of CO2 emissions is taken care by Government Policy by adopting more efficient higher size units based on super-critical technology for all new units installed in 13th plan and beyond. CO2 emission depend on the efficiency of the thermal power plants. ……The super-critical technology has already been fully developed and operationalised in India. Even more efficient ultra-super-critical units are being adopted by power utilities for their future projects. Further R&D project has also been taken up to develop more efficient Advanced Ultra-Super-critical technology'*.

The applicants wish to reiterate the submissions made in original application at Para 6.10-subpara 2(vi) at Page 44 where several findings of esteemed research institutes have been produced to make it clear that super-critical technology though better than sub-critical, is not the best. It is submitted that the performance efficiencies of subcritical, supercritical and ultra-supercritical are 33%, 38.5% and 43% respectively. Thus, efficiency of 'ultra-supercritical' system at 43% is 5% more efficient than 'super-critical' system and 10% more efficient than the 'sub-critical' system. Thus, the statement made therein at Para 9(d) by R-3 at pg 290 that the '*Ultra-Supercritical technology has marginal efficiency improvements over super-critical technology*' is strongly denied. The applicants' contention is that instead of super-critical technology, the government shall allow only ultra-supercritical units in upcoming thermal power plants. Being a capital intensive sector, the replacement cost in future could be easily avoided if the most efficient technology is adopted at early stage

itself. Therefore, it is very important that new thermal power plants are asked for installation of the latest ultra-supercritical technology only.

19. **Installation of pollution control equipment:** That the Respondent No. 3 at para 6.10 (i) at pg 282 has stated that installation of FGD, cooling tower etc requires time and may require a shutdown period. It is submitted that time consumption should not be a ground for not implementing with the necessary pollution control measures especially in cases where larger question of public health and environment is involved. As a measure to stop long delays in implementation of the said measures, the Respondents must make a list of thermal power plants and an action plan after creating an inventory of all the thermal power plants in the country. There should be monthly targets for installation of the control equipments which should be supervised and monitored by R-1 and R-2 with help of regional boards and offices.

20. **Constraints with Phasing Out the Older units:** That the applicants have made two submissions in the original application-first, the relaxation given to older power plant units should be lifted and strict emission limits be prescribed and secondly, the older inefficient units where such limits cannot be achieved and which have served their designed life should be shut down or replaced. It is submitted that the thermal power sector contributes significantly to the major air pollution in the country and smaller units are the most polluting ones. The applicants wish to present few findings from the Proceedings of the CSE Workshop (attached as Annexure A-2) which was attended by most of the major power companies and government agencies. It is submitted that out of total coal based power, approximately 44% of power comes from smaller units. A chart providing the unit size distribution from the Proceedings is reproduced below:-

Unit Size Distribution in India (MW)

Unit size	**Capacity in MW**				
	+25 years	**1990–2003**	**2004–08**	**2009–Aug'2016**	**Total**
up to 250 MW	28,610	16,292	2,070	5,816	52,788

> 250 and <500 MW	–	5,350	3,850	20,810	30,010
500 MW and above	5,500	9,500	5,980	82,814	1,03,794
Total	34,110	31,142	11,900	1,09,440	1,86,592

As per Draft Electricity Plan of CEA, published in December, 2016, a total capacity of 50,025 MW coal based power projects is currently under different stages of construction and are likely to yield benefits during the period 2017-22. The report reveals that no coal based capacity addition is required till the year 2027. Following is an excerpt from the Report:

> *"Studies indicate that a coal based capacity of 44,085 MW is required during the period 2022-27 with no coal based capacity addition requirement during the year 2017-22. Now a coal based capacity of 50,025 MW is already under construction which likely to yield benefits during 2017-22. Therefore, this excess coal based capacity would fulfil the capacity requirement for the years 2022-27.* **(Base Case).**
>
> *Studies indicate that a coal based capacity of 50,025 MW is required during the period 2022-27 with no coal based capacity addition requirement during the year 2017-22. Now a coal based capacity of 50,025 MW is already under construction which likely to yield benefits during 2017-22. Therefore, this excess coal based capacity would fulfil the capacity requirement for the years 2022-27.* (**Low Hydro Scenario-excluding the 21,600 MW imports from hydro plants of neighbouring countries**)".

The Report further claims:

> *"To accommodate high quantum of Renewable Energy Systems (RES) into the grid, thermal plants are likely to run at low Plant Load Factor (PLF) in future. Many plants may get partial/nil schedule of generation".*

This would mean that several plants may face viability issue and risks of economic losses. The report also shows that national average PLF of Coal

based power generating stations has decreased from 78.9% in 2007-08 to 62.0% in 2015-16. Thus, it can be safely said that phasing out of older inefficient units of 34,000 MW may not have much impact on power production as the PLF of existing power plants can be increased to compensate the power deficit and there are already upcoming thermal power units with capacity of more than 50,000 MW which is also going to be operationalise soon. This will in fact prove to be more economical as this will ensure optimum utilization of the existing and new power plants, which despite being efficient- are yet to be run to their full capacity. It is also important to mention here that low PLF would mean more economic burden on the thermal power plants, the cost of which will be ultimately transferred to consumers only. On the other hand, apart from all this economic benefit, the cumulative ecological benefit will be numerous. Thus, there is no economic reason as such for not phasing out the older units which are less efficient, most polluting and where pollution control measures are also difficult to achieve.

In such scenario, the reply of CPCB that the stricter standard for PM is not feasible to be achieved in older and smaller power plants in fact supports our concern, the reason for which these plants should be shut down at the earliest. From the above statistics, it is abundantly clear that closing down such old, inefficient and polluting units will not create power shortage and the deficit can be met by the existing power plants running at such a low PLF as well as compensated by the surplus units under commissioning. Copy of the relevant extracts from Draft Electricity Plan of CEA, published in December, 2016 is annexed herewith as **Annexure A-5.**

21. **Cost Implication on Pollution Control Equipment:** That the R-3 in its reply at pg 292 has stated that there will be huge cost implication for compliance of new environmental norms dated 07.12.2015 in the order of 1-1.5 Crores/MW and this will increase in power tariff to consumers. The applicants agree that there will be some cost associated with the upgradation of technology and pollution control measures. However, the applicants have produced numerous

reports and documents to indicate that the cost of environment and human health in absence of these measures is also huge on people of India and its economy. The applicants submit that as per Haryana government which has engaged such measures reported that the cost imposed on power producers in present scenario is as low as 22 paisa per unit of electricity produced. The applicants wish to refer to the data provided by Haryana government in CSE Workshop Proceedings which is annexed as Annexure A-2**.** The applicants crave leave to produce further economic analysis if directed by the Hon'ble tribunal in support of this argument.

22. **Powers of MOEFCC prescribing installation of FGD and SCR as a mandatory requirement:** That the R-1, MoEFCC in its reply at para 6.10.2 at Pg 223 has dispensed with its responsibilities on the issue by stating:

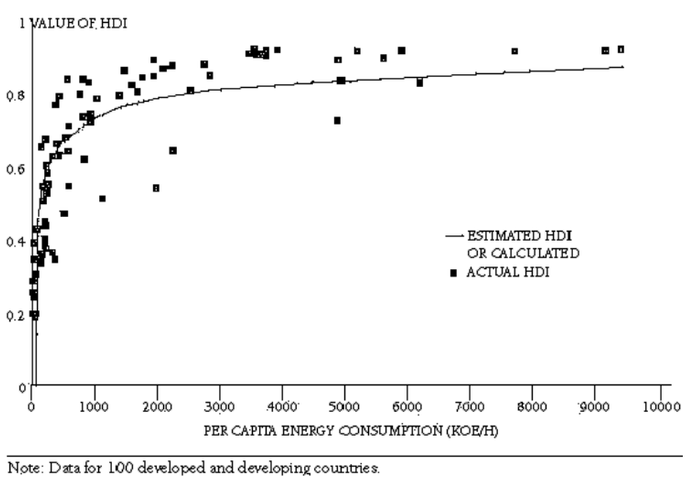
> '*It is submitted that MOEFCC does not prescribe technology for achievement of standards and the decision to select suitable technology to comply with notified parameters is left to the industry. However, it is submitted that in order to comply with the notified standards existing plants (500 MW and above) and new plants may have to install FGD & SCR, which will help in reduction of emission of SO2, & NOx by 48% each from the existing rate of emission.*'

The applicants deny the exception taken by R-1 on this critical issue. MOEFCC being the supreme authority is responsible for environment protection and sustainable development of the country. Such argument is liable to mortify the duty and powers given to the MOEFCC under Environment (Protection) Act, 1986 and under various constitutional provision under Article 21. It appears that all the respondents are well informed about the criticality of the problem and are also well aware of the solutions. The applicants further point out that that the R-1 in the same notification has mandated Cooling Towers and while giving Environmental Clearances mandates installation of ESP as pre-condition. However, for reasons best known, it refrains from prescribing similar

technological measures in case of SO2 and NOx, despite being aware of the consequences.

23. **Regarding Per Capita Energy Consumption and Development of Country:** That the R-3, Ministry of Power has proceeded on the premise that it is necessary and desirable for India to match the per capita electricity consumption in developed and other developing countries (Pg 261). It is submitted that the weather conditions, environmental carrying capacity, economics, population etc. vary between countries. On the other hand, the impacts of air pollution from thermal power plants will be much greater in India because of its high population density and greater pressure on environment due to limited land, limited resources as well as limited carrying capacity of the environment to absorb stress on its ecology. Therefore, it is highly unsustainable aspiration for a country like India to achieve same electricity consumption as that of U.S. The argument given by R-3 is based on the assumption that higher consumption of electricity leads to higher standard of living and welfare of the people. The applicants wish to produce certain facts from following studies.

(i) Study titled "Electricity Supply and Demand Side Management Options" prepared for the World Commission on Dams by Anton Eberhard of University of Cape Town, South Africa and others says:



Note: Data for 100 developed and developing countries.

"*Figure… shows the relationship between per capita energy consumption (commercial and traditional energy) and the*

Human Development Index (HDI) for 100 developed and developing countries. The graph suggests that for countries with low levels of energy services, even small inputs of energy are associated with significant welfare improvements. …….At higher energy consumption levels, further increases do not seem to impact greatly on human development. The decreasing marginal benefits of energy supply on human development parallels GDP-energy decoupling that has taken place in various countries during the 20th century"

The above Figure shows the relationship between per capita energy consumption and HDI. This indicates that higher consumption of electricity cannot be assumed to lead to higher welfare. It is more likely that higher consumption of electricity will lead to minimal increase in welfare or HDI. On the other hand, the environmental consequences of increases in thermal power generation will lead to lower welfare. Therefore, unrestricted increases in consumption of electricity are likely to be counterproductive. Copy of the relevant extracts of the Study titled "Electricity Supply and Demand Side Management Options" prepared for the World Commission on Dams by Anton Eberhard of University of Cape Town, South Africa and others is annexed herewith as **Annexure A-6**.

(ii) Study titled "Electricity consumption and economic growth in India" by Sajal Ghosh of Indira Gandhi Institute of Development Research, Mumbai found absence of long-run relationship between economic growth and electricity consumption. The study concluded that there exists a unidirectional causality running from economic growth to electricity consumption without any feedback effect. Implication is that economic growth leads to higher consumption of electricity but higher consumption of electricity does not lead to economic growth. Copy of the said study is annexed herewith as **Annexure A-7**.

(iii) Another study, titled “Electricity Prices in India” by Pierre Audinet of International Energy Agency, Washington concludes: “There has been a sharp decrease of the ratio of electricity consumption growth to GDP growth in the 1990s. In other words, in the past decade, electricity consumption growth did not follow economic growth.”

This same phenomenon has been observed for China where from 1980-1990 where the average annual growth rate of GNP was 9.0 percent with decrease in energy consumption per 10,000 yuan GNP decreased from 13.36 lee in 1980 to 9.3 lee in 1990, a drop of 30 percent. This indicates a de-coupling of energy consumption and economic growth.

It follows that increase in consumption of electricity at lower levels from 0 to 1000 kwh per capita per year are beneficial for welfare. Increases beyond this do not contribute to welfare or economic growth. Further, with improvement in technology, more energy efficient electrical equipments, shift from industrial based to service based economy, concepts of green infrastructure etc. also have a significant impact on per-capita electricity use.

Copy of the study titled as “Electricity Prices in India” by Pierre Audinet of International Energy Agency, Washington and copy of the article titled as “Economic development, energy, and the environment in the people's Republic of China” is annexed herein as **Annexure A-8 (Colly).**

24. **Inadequacies in EIA Process, Siting Guidelines and Regulation of Water Abstraction:** It is submitted that the applicants have provided a detailed analysis on the severe inadequacies in the present EIA process, the Siting Guidelines and regulation of water abstraction in para 6.9 (Page 34) of the original application. The applicants also sought directions from this Hon’ble Tribunal to strengthen the EIA of Thermal Power Plants with some specific

steps mentioned at para 9(b), (c), (e), (f), (g), (h). The same is not repeated here again for sake of brevity. However, none of the Respondents, especially R-1, MOEFCC in its replies has countered the facts and directions sought on those critical issues. Therefore, the facts and submissions made by applicants on those issues may be deemed to be accepted by all the respondents.

In view of the aforesaid, it is humbly prayed that on the basis of the submissions made in the present rejoinder affidavit, directions prayed in the original application may be granted by the Hon'ble Tribunal.

Filed by

PARUL GUPTA
ADVOCATES FOR THE APPLICANTS
28/1, MAHARAJA AGRASEN MARG
GOVINDPURI, KALKAJI,
NEW DELHI – 110019

VERIFICATION

I, Debadityo Sinha, S/o Smt Durba Roy, R/o 28/1, Maharaja Agrasen Marg, Govindpuri, Kalkaji-19 aged about 27 years do hereby verify that the contents of paras 1 to 24 are true and that I have not suppressed any material fact.

Applicant No. 1

BEFORE THE NATIONAL GREEN TRIBUNAL
AT NEW DELHI

ORIGINAL APPLICATION NO. 221 OF 2016

IN THE MATTER OF:

DEBADITYO SINHA & ANR…. ….. …. ….. …… … ……**APPLICANTS**

Versus

MINISTRY OF ENVIRONMENT, FORESTS

AND CLIMATE CHANGE & ORS… …. …. …. …. …**RESPONDENTS**

AFFIDAVIT

I, Debadityo Sinha, S/o Mrs. Durba Roy, R/o 28/1, Maharaja Agrasen Marg, Govindpuri, Kalkaji, New Delhi-110019 aged about 27 years do hereby solemnly affirm and declare as under:

1. That I am the applicant No. 1 in the abovementioned application and I am fully conversant with the facts and circumstances of the case and therefore competent to swear this affidavit.

2. That I have read over the contents of the rejoinder to the replies filed by the Respondents No. 1, 2 and 3 and the same is true and correct and is drafted on my instruction.

DEPONENT

VERIFICATION:-

Verified on this the 17 day of February 2017 that the contents of the above affidavit are true and correct. No part of it is false and nothing material has been concealed therefrom.

DEPONENT

BEFORE THE NATIONAL GREEN TRIBUNAL

AT NEW DELHI

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IN THE MATTER OF:

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6	**Annexure A-5** Copy of the relevant extracts from Draft Electricity Plan of CEA, published in December, 2016	
7	**Annexure A-6** Copy of the relevant extracts of the Study titled "Electricity Supply and Demand Side Management Options" prepared for the World Commission on Dams by Anton Eberhard of University of Cape Town, South Africa	
8	**Annexure A-7** Study titled "Electricity consumption and economic growth in India" by Sajal Ghosh of Indira Gandhi Institute of Development Research, Mumbai	

9 **Annexure A-8**

Copy of Study titled as “Electricity Prices in India” by Pierre Audinet of International Energy Agency, Washington and copy of the article titled as “Economic development, energy, and the environment in the people's Republic of China”

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NEW DELHI
DATED: 17.02.2017

Comprehensive Study on Air Pollution and Green House Gases (GHGs) in Delhi

(Final Report: Air Pollution component)

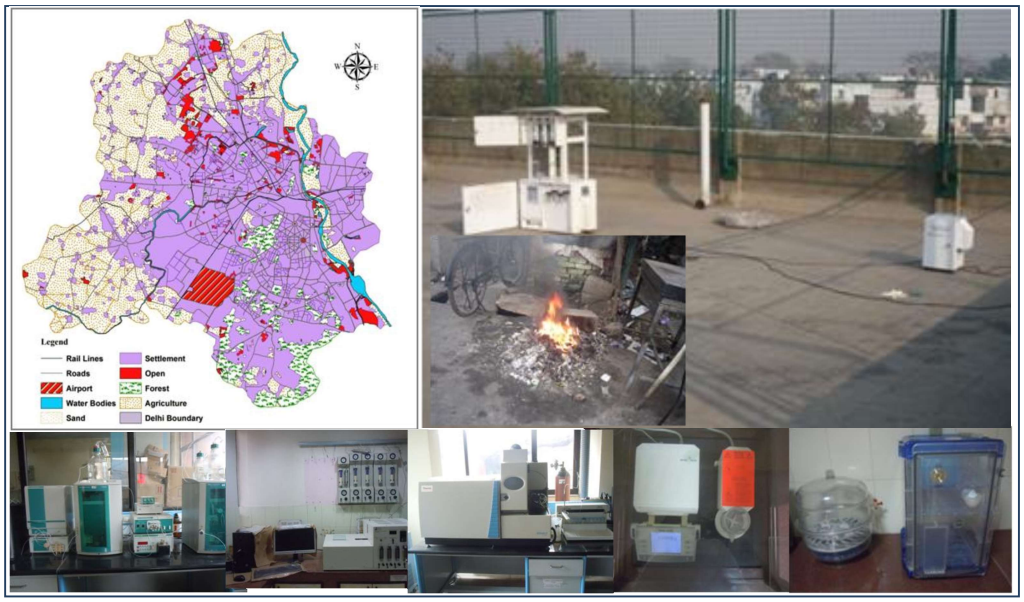
Submitted to

Department of Environment

Government of National Capital Territory of Delhi

and

Delhi Pollution Control Committee, Delhi



Mukesh Sharma; PhD and Onkar Dikshit; PhD

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January 2016

expected PM control will be about 15 to 30 % from this source and SO_2 emissions will become negligible.

Diesel Generator Sets: The primary pollutants from internal combustion engines are oxides of nitrogen and PM. For Delhi and NCR, the sulphur content should be reduced to 500 ppm in HSD (if not already in use) as has been done for vehicles; a reduction of 15 to 30% of PM emission from this source is expected. It will have a major impact on reduction of SO_2 and secondary particles. The DG sets should be properly maintained and regular inspection should be done. All efforts should be made to minimize uses of DG sets and regular power supply should be strengthened. Since small DG sets are used at the ground level and create nuisance and high pollution, it is recommended that all DG sets of size 2 KVA or less should not be allowed to operate; solar powered generation, storage and inverter should be promoted.

- Secondary particles

  What are the sources of secondary particles, the major contributors to Delhi's PM? These particles are expected to source from precursor gases (SO_2, and NO_x) which are chemically transformed into particles in the atmosphere. Mostly the precursor gases are emitted from far distances from large sources. For sulfates, the major contribution can be attributed to large power plants and refineries. The NW wind is expected to transport SO_2 and transformed it into sulfates emitted from large power plants and refineries situated in the upwind of Delhi. However, contribution of NO_x from local sources, especially vehicles and power plants can also contribute to nitrates. Behera and Sharma (2010) for Kanpur have concluded that secondary inorganic aerosol accounted for significant mass of $PM_{2.5}$ (about 34%) and any particulate control strategy should also include control of primary precursor gases.

  There are 13 thermal power plants (TPP) with a capacity of over 11000 MW in the radius of 300km of Delhi, which are expected to contribute to secondary particles. Based on the study done by Quazi (2013), it was shown that power plants contribute nearly 80% of sulfates and 50% nitrates to the receptor concentration. A calculation assuming 90% reduction in SO_2 from these plants can reduce 72% of sulphates. This will effectively reduce PM_{10} and $PM_{2.5}$ concentration by about 62 $\mu g/m^3$ and 35 $\mu g/m^3$ respectively. Similarly 90% reduction in NO_x can reduce the nitrates by 45%. This will effectively reduce PM_{10} and $PM_{2.5}$ concentration by

about 37 $\mu g/m^3$ and 23 $\mu g/m^3$ respectively. It implies that control of SO_2 and NO_x from power plant can reduce PM_{10} concentration approximately by 99 $\mu g/m^3$ and for $PM_{2.5}$ the reduction could be about 57 $\mu g/m^3$.

- Secondary Organic Aerosols

  The contribution of secondary organic aerosols (SOA) in Delhi has not been done. However, Behera and Sharma (2010) have estimated that the SOA is about 17 percent of total $PM_{2.5}$ in Kanpur, another city in Ganga basin. This implies that emissions of VOCs (volatile organic compounds) need to be controlled both in and outside of Delhi, as SOA can be formed from VOC sources at far distance from the receptor. It is recommended that all petrol pumps in Delhi should install vapour recovery system to reduce VOC emissions both at the time of dispensing petrol/diesel but also at the time of filling of storage tank at the petrol pumps.

- Biomass burning

  The enhanced concentration in October-November is possibly due to the effect of post-monsoon crop residue burning (CRB). The CRB should be minimized if not completely stopped. All biomass burning in Delhi should be stopped and strictly implemented. Managing crop residue burning in Haryana, Punjab and other local biomass burning is important. Potential alternatives to CRB: energy production, Biogas generation, commercial feedstock for cattle, composting, conversion in biochar, Raw material for industry

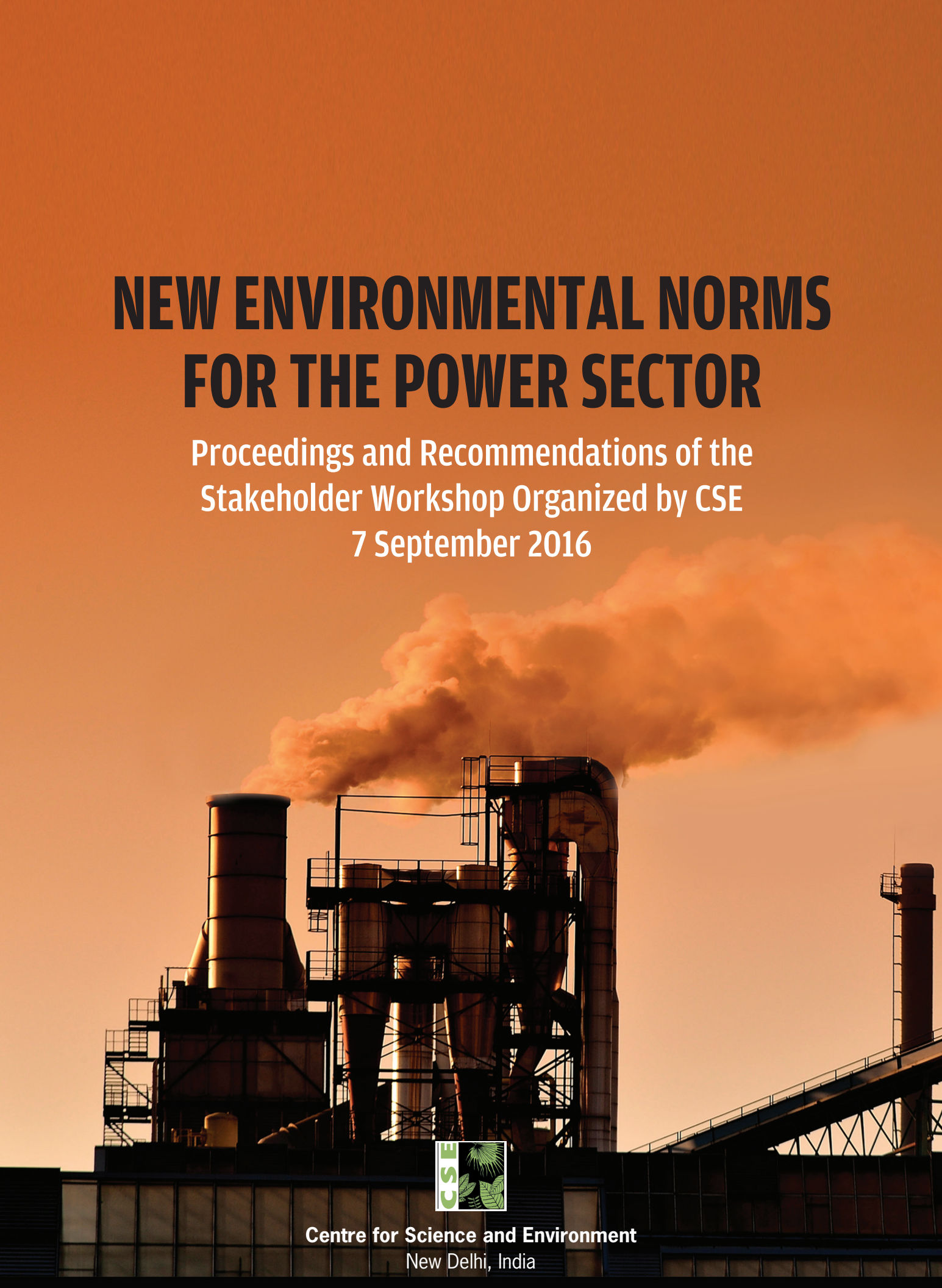
Action Plan

The study recommends that the following control options for improving the air quality, these must be implemented in a progressive manner.

- Stop use of Coal in hotels/restaurants
- LPG to all
- Stop MSW burning: Improve collection and disposal (landfill and waste to energy plants)
- Construction and demolition: Vertically cover the construction area with fine screens, Handling and Storage of Raw Material (completely cover the material), Water spray and wind breaker and store the waste inside premises

NEW ENVIRONMENTAL NORMS FOR THE POWER SECTOR

Proceedings and Recommendations of the Stakeholder Workshop Organized by CSE 7 September 2016



Centre for Science and Environment
New Delhi, India

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Material from this publication can be used, but with acknowledgement.

Published by
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ACRONYMS

SO_2	Sulphur dioxide
NOx	Oxides of nitrogen
SPM	Standard particulate matter
kWh	Kilowatt hour
MWh	Megawatt hour
PPA	Power Purchase Agreement
FGD	Flue gas desulphurization
SCR	Selective Catalyst Reduction
SNCR	Selective Non-Catalyst Reduction
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
POSOCO	Power System Operation Corporation Limited
CPCB	Central Pollution Control Board
MoP	Ministry of Power
NTPC	National Thermal Power Corporation Ltd
MoEF&CC	Ministry of Environment, Forest & Climate Change
HERC	Haryana Electricity Regulatory Commission

EXECUTIVE SUMMARY

In December 2015, the Ministry of Environment, Forest & Climate Change (MoEF&CC) announced tighter standards for coal-based thermal power plants. Centre for Science and Environment's (CSE) preliminary survey of power companies and manufacturers revealed, however, that little progress has been made towards the implementation.

CSE felt it would be important to invite key stakeholders to share and address the issues to push the implementation of revised environmental standards. Accordingly, it organized a conference on '*New Environmental Norms: The Way Forward*' on 7 September 2016.

The conference was very well attended, with around fifty participants. Anil Razdan, ex-Power Secretary, gave the keynote address. Speakers from the power industry, including Ashish Basu, Chairman, Association of Power Producers; Alind Rastogi, Executive Director, NTPC; and Sanjay Sagar, CEO, JSW Energy, detailed the implementation challenges and progress made by the industry. Senior officials from CERC and state ERCs talked about investments and cost recovery. Attendants comprised senior officials from state generating companies of Punjab, Gujarat and Telangana and leading private power companies, including Tata Power, Reliance and CESC. Major global pollution control technology suppliers, including GE, Thermax, Mitsubishi and Doosan, also participated in the conference.

One major conclusion of the conference was that technology availability or suitability for Indian coal was not the impediment—electrostatic precipitators (ESPs) can be augmented to achieve norms; flue gas desulphurization (FGD), to control SOx, is a mature technology; suppliers are confident that Selective Catalyst Reduction (SCR) technology will work for Indian coal to control NOx.

Moreover, the costs of pollution control technology are manageable (see Table 1: *Cost of pollution-control technology*). The exact investment needed by a plant would depend on the combination of upgradation and new installation required, which in turn would depend on existing abatement technology, actual emissions, applicable norms and age of the plant. Based on the projected capital expenditures given by the plants in Haryana, the State Electricity Regulatory Commission (HERC) estimated a generation tariff impact of around 22 paisa per unit. ICRA, a ratings company, estimated a similar impact on the cost of generation.

Table 1: Cost of pollution-control technology

Technology required	Approx. cost
ESP upgradation	Rs 5–15 lakh/MW
Partial FGD	Rs 25–30 lakh/MW
FGD	Rs 50–60 lakh/MW
De-NOx	Rs 10–15 lakh/MW
SCR/SNCR	Rs 20–25 lakh/MW

However, some legitimate concerns need to be addressed. Commercial issues—financing for the investment required and cost recovery through tariff increase—remain unresolved. Therefore, concerted action steps from all policymakers/regulators—various Electricity Regulatory Commissions (ERC), Central Electricity Authority (CEA)/Ministry of Power (MoP) and MoEF&CC/Central Pollution Control Board (CPCB)—are critical to achieve timely implementation.

Timelines are tight but were achievable when the norms were announced. However, little progress has been made over the last nine months during which pre-execution work (need assessment, cost estimates and tariff application) could have easily been done. Meeting PM, NOx and water use norms is still possible given procurement time of less than 6 months; installation can be done during scheduled shut down or may need less than one month of shut down. However, procurement and installation of FGD could take up to 24 months. Additional time may now be needed for some plants. Plants under construction need to change construction plans and procure equipment to meet the new norms from 1 January 2017, which would be a challenge. MoEF may therefore need to revisit implementation schedule.

Immediate action steps

1. MoEF should survey the implementation status of power plants to assess compliance with the new norms and develop a revised schedule. Revision of timelines should be on a case-by-case basis backed by strong commitments, clear evidence of progress (contract with vendor etc.) and bank guarantees. Plants under construction should meet the standards on the commissioning date since modification at a later may be disruptive; however, retrofitting to meet the norms within the next one to two years may be permitted if there are techno-economic benefits. Plants with firm retirement or replacement plans may be allowed to operate in the interim.

2. CEA should act as the key technical advisor and prepare a 'Technology Guidelines' document that details technological options to control pollutants, their suitability for Indian coal, life cycle and O&M costs. Capital cost benchmarking for the options should be done. Work that has already been done by industry leaders, such as NTPC can be used.

3. CERC should prepare a simplified tariff application for in-principle capital expenditure (capex) and preliminary tariff approval that should also be used by state regulators. ERCs should ask plants to urgently provide unit-wise assessment of capex required and tariff impact.

4. CERC could consider uniform tariff increases based on minimum capital costs that are in accordance with CEA guidance. (Final tariff approvals can be modified to account for approved costs.) The tariff increases could be staggered to make them acceptable to discoms/consumers.

5. CEA and CPCB should develop a monitoring mechanism and regularly track the progress made by individual plants in installing equipment. The quarterly progress report should be made available in the public domain.

6 CEA and POSOCO need to prepare a scheduled shut-down plan for the entire fleet for installation of pollution control equipment to avoid supply disruption.

Policy recommendations

1. Government should divert a portion of National Clean Energy Fund (NCEF)—a coal cess of around Rs 23,000 crore would be recovered from the power sector in 2016–17—to support installation of pollution control equipment. Support could come in the form of subsidized loans, credit enhancement or even equity component of the investment required.

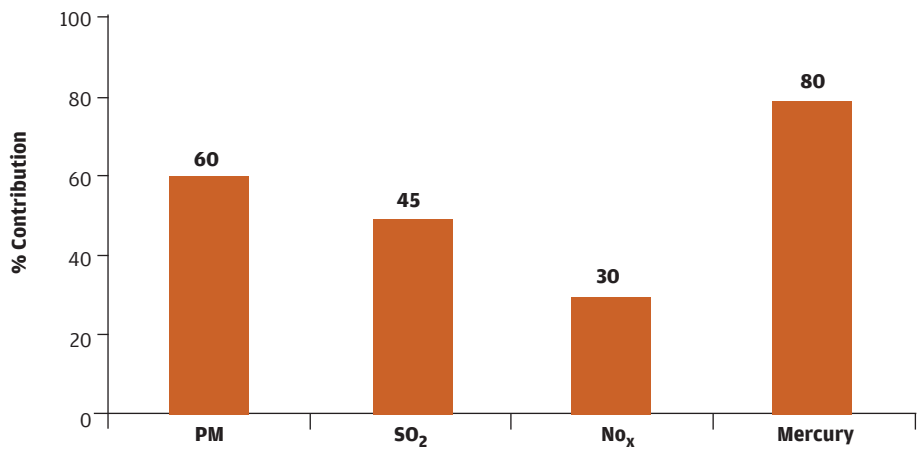
2. The government should work on an expedited plan to retire or replace old capacity based on operating and environmental performance and incremental investment required to comply with new norms. Incentives should be given for replacing the units with SC units— for e.g., they may not need Environmental Clearances (ECs). New investors can be encouraged to come in by giving them coal linkages and PPAs associated with the old plants.

3. Incentives should be considered for plants that meet norms by the deadline. For e.g. 'merit order dispatch' preference could be given to these plants.

INTRODUCTION

Coal is central to India's energy needs. It contributes around 75 per cent of India's current electricity generation and, according to NITI Aayog projections, will remain the dominant source of power for the next couple of decades. Coal is abundantly available and provides a reliable, cheap baseload power. But the coal-based thermal power industry is responsible for a significant share of emissions of the industrial sector in India and it therefore has an outsized impact on air pollution (see Graph 1: *Contribution of coal-based power sector to industrial emissions*). Cleaning the sector will have vast benefits for the environment and on human health.

Graph 1: Contribution of coal-based power sector to industrial emissions



Source: Centre for Science and Environment, 2014–15

Recognizing the central role thermal power plays in worsening air quality, the Ministry of Environment, Forest & Climate Change (MoEF&CC) announced in December 2015 tighter standards for coal-based thermal power plants. The new standards aim to drastically cut emissions of particulate matter (PM), sulphur dioxide (SO2), oxides of nitrogen (NOx) and mercury. In addition, the new norms also require power plants to sharply curtail freshwater use.

Based on extensive discussions with industry experts, equipment suppliers and power plants, followed by a roundtable with stakeholders in July 2016, CSE believes that the standards are practical and achievable; techno-economically feasible pollution control options are widely available. We believe, however, that some issues need to be quickly addressed to achieve compliance with the revised standards.

CSE felt it would be helpful to invite all the stakeholders—power generation companies; equipment manufacturers; environment, tariff and power regulators; and industry experts—to share and address the issues to push the implementation of revised environmental standards. Accordingly, CSE organized a conference on '*New Environmental Norms: The Way Forward*' at India Habitat Centre on 7 September 2016.

Expediting implementation of new norms

MoEF&CC has given a tight albeit achievable deadline to meet the new standards (see Table 2: *Standards*). Existing plants were given two years (December 2017); plants commissioned after 1 January 2017 will have to comply from the start of their operations.

Table 2: Standards (in mg/Nm^3)

	PM	SO_2	NO_x	Mercury
Current standards	150–350	none	none	none
New standards				
Units installed till 2003	100	<500 MW—600 >=500 MW—200	600	>=500 MW—0.03
Units installed between 2004 and 2016	50	<500 MW—600 >=500 MW—200	300	0.03
Units installed after Jan 2017	30	100	100	0.03

CSE's preliminary survey of power companies and manufacturers over the last three months revealed, however, that little progress has been made towards the implementation of new standards. The plants raised several issues for not making sufficient progress. Many plants have insufficient knowledge or experience of advanced pollution control technologies. Plants expressed concern that the pollution control technologies were unsuitable for high-ash Indian coal and manufacturer capacity is insufficient to meet the projected demand; some think space—for the installation of pollution control equipments and storage of raw material—would be a constraint. Most plants believed that the costs to instal pollution control equipment were high with little clarity on cost recovery. They also felt the timelines were tight.

Accordingly, the conference had the following objectives:

- To arrive at an understanding of various technology solutions to meet new standards and address issues of suitability for Indian coal, cost and supplier capacity.
- To understand regulatory bottlenecks (tariff increase and capital investment approvals) and financial issues, discuss cost recovery and financial support ideas.
- To understand any other issues, such as supplier capacity, raw material availability, waste management etc.
- Key stakeholders agree on implementation timelines and environment and power regulators devise a monitoring and enforcement plan.

New standards: rationale

The new standards were based on CPCB and MoEF&CC's extensive consultations with experts and industry studies. The norms considered a range of factors: age and size of the units and available pollution control technologies. CPCB analysed reported data emissions—all plants report PM and several plants also tracked SOx and NOx emissions to assess norms that are achievable. Norms in other major countries, including China, provided a peer benchmark.

Environmental clearances given since 2003 required units larger than 500 MW to keep space for future installation of flue gas desulphurization (FGD); therefore space availability isn't an issue for these units. Also, ECs after 2008 required plants to meet PM of 50 mg/Nm^3, which means that plants that became operational after 2008 should be able to meet this standard.

Finally, the power sector had itself agreed to improve its environmental performance under the voluntary 2003 Charter on Corporate Responsibility for Environmental Protection (CREPS), which included meeting tighter PM emissions standards (100 mg/Nm^3) and implementing SOx/NOx standards by 2005–06. The sector failed to act on its voluntary commitment. In fact, a 2015 CSE study revealed that almost two thirds of coal-based thermal power plants failed to comply with even the prevailing loose standards.

POLLUTION-CONTROL TECHNOLOGY

Many large-scale manufacturers, including BHEL, Mitsubishi and GE-Alstom, have strongly emphasized that pollution control technologies options are widely available and can easily meet even the tightest standards that have been proposed. We have detailed below an overview of various options based on the size and vintage of units, required emission levels that need to be achieved, indicative range of investment needed and installation time required.

The two most important parameters to decide what pollution-control options are most appropriate are age and size of the unit. The Indian fleet can be broken into the following categories based on these parameters:

Table 3: Unit size distribution in India (MW)

Unit size	Capacity in MW				
	+25 years	1990–2003	2004–08	2009–16*	Total
up to 250 MW	28,610	16,292	2,070	5,816	52,788
> 250 and <500 MW	–	5,350	3,850	20,810	30,010
500 MW and above	5,500	9,500	5,980	82,814	1,03,794
Total	34,110	31,142	11,900	1,09,440	1,86,592

*Note: * As on 31 August 2016*

Technology options and costs

Investments in plants/units that have exceeded their design life of 25 years (34.1 GW capacity) must be made carefully considering their efficiency and availability. Most of them should probably be expeditiously shut. Basic upgradation targeting mainly PM control may, however, suffice in the interim. This relaxation must be accompanied by a clear plan to decommission units and, in a few cases, replace them with new supercritical units. Units with good operating performance, low cost of generation and recent R&M that has extended remaining life may be allowed to invest so they can meet the new standards.

Particulate matter (PM)

a) Units commissioned between 1990 and 2008 (43.0 GW total capacity) may need to upgrade the ESP to meet the PM norms of 100 and 50 mg/Nm^3. In some cases it may involve adding fields in series or parallel or increasing the height of ESP. The cost of these renovations would be around Rs 15 lakh/MW.

b) Most units installed after 2008 (109.4 GW capacity) were required to meet PM norms of 50 mg/Nm^3 by the environment clearances. Therefore, a basic performance revamp may suffice for these units. However, some units were required to meet 100–150 mg/Nm^3 and others are poorly performing—an investment of at most Rs 10 lakh/MW may be required for these units.

c) Units in pipeline should be able to meet the 30 mg/Nm^3 PM standard with a combination of ESP and FGD. In fact an integrated design would mean that the ESP size can be made smaller than a standalone one for meeting the norm.

Sulphur dioxide (SO_2)

a) Units of size less than 500 MW installed between 1990 and 2016 (54.2 GW capacity) need to meet the SOx norm of 600 mg/Nm^3. These units may choose economical options such as partial FGD or sorbent injection. The cost is estimated to be around Rs 25–30 lakh/MW (assuming FGD for half the plant capacity).

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b) Units of size 500 MW and more, installed between 1990 and 2016 (98.3 GW capacity), have to instal limestone-based wet FGD or lime-based dry FGD, depending on raw material and water availability. The costs are estimated to be Rs 50–60 lakh/MW.

FGD is a mature technology for controlling SOx. It is used in many countries and has been shown to be effective for a wide range of coal qualities and operating conditions. China has installed FGD in over 91.4 per cent of its fleet in recent years.

c) Upcoming units can meet the SOx standard by installing FGD.

Oxides of nitrogen (NOx)

a) Minimal measures are needed to meet emissions of less than 600 mg/Nm^3 for the 31.1 GW of capacity installed between 1990 and 2003 on a case-to-case basis. Some units are already meeting these levels, according to data reported by the plants to CPCB. We have conservatively estimated an investment of Rs 10 lakh per MW.

b) A capacity of 121.3 GW that was installed after 2003 has to reduce emissions to 300 mg/Nm^3. According to CPCB, some plants are already meeting these values. Manufacturers, including BHEL, have already been supplying boilers that meet these emissions. Those plants whose emissions exceed the norms will need to choose from several options including burner modification, over fire air supply (OFA) etc., depending on the base level of emissions and technical constraints. The costs for these upgrades will be around Rs 10–15 lakh/MW. In rare cases, plants may need to instal SNCR or SCR. These would cost Rs 20–25 lakh/MW.

c) Upcoming units need to meet the NOx emissions of 100 mg/Nm^3. SCR and SNCR technologies have been used globally to cut NOx to these levels. Some industry players, however, feel that the technology's effectiveness needs to be established for Indian coal (high ash, chemical composition and physical characteristics). NTPC will run five pilot programmes to assess the technology. Suppliers are confident that the technology will work with possibly minor tweaks.

Table 4: Investment required for pollution-control technology

Technology required	Capacity in GW	Approx. cost (in Rs crores)
ESP upgradation	152.4	Rs 5–15 lakh/MW
Partial FGD	54.2	Rs 25–30 lakh/MW
FGD	98.2	Rs 50–60 lakh/MW
De-NOx	152.4	Rs 10–15 lakh/MW
SCR/SNCR	Upcoming	Rs 20–25 lakh/MW

An existing plant would obviously not require all pollution-control equipment to be installed. For example, many new plants, installed after 2008, may not require to do anything for PM and NOx control. The exact investment required by a plant would depend upon a number of factors— age, size and technology of units; currently installed pollution-control equipment and their maintenance status; actual emissions; and applicable norms.

Tariff impact: Haryana SERC estimated generation tariff impact of 22 paisa and consumer tariff impact of 26 paisa per unit based on submissions by power plants in Haryana. ICRA, a rating agency, analysis indicated similar impact on tariff based on average investment by plants.

TIMELINES

Power producers have expressed apprehensions about complying with the new standards within timelines given in the notification (December 2017 for existing plants and January 2017 for new plants):

a) Plants contend that pre-execution activities (technology finalization, cost estimates, in-principle tariff approval and financial tie-ups) could take up to nine months and design, procurement and installation can take another two years.

Some of the delay was avoidable; indeed, plants like NTPC, Tata Power have completed some of the pre-execution work. Design and procurement of most pollution control equipment would take less than six months; installation can be done during the scheduled maintenance downtime or may need less than a month of downtime. FGD installation is the most time-consuming process, taking up to two years (see Table 5: *Time required to instal different pollution-control equipments*). MoEF may need to revise timelines based on a survey of progress. Extensions should be on a case-by-case basis subject to plants giving firm commitments backed by bank guaranty and evidencing progress (signed contracts with vendors).

b) Regulatory support is required to ensure timely implementation, including tariff increase approvals; POSOCO/CEA coordination is essential to shut plants for upgrades in a planned manner. Technology benchmarking by CEA and simplified tariff applications and expedited in-principle approvals by ERCs would shorten implementation timelines.

c) Power plants believe supplier capacity to execute this scale of projects is limited and costs may rise due to supply shortage. However, manufacturers claim that global supply will quickly rise to meet demand—historically, prices for FGD etc. fell as supply increased in the international markets.

d) Plants under construction need to change their construction plans, raise additional financing, and order and instal new equipments. They may need time beyond 1 January 2017 to comply with the new standards and their additional costs also need to be considered by regulators. Many plants in the pipeline are planning retrofit at a later stage but this is not a judicious plan. Plants must be asked to upgrade at the construction stage itself to comply on the commissioning date. Time extension for compliance and retrofitting can be considered on a case-by-case basis if it is techo-economically advantageous.

Table 5: Time required to instal different pollution-control equipments

Technology	Construction time	Downtime
Electrostatic precipitator (ESP)	~ 3–6 months	~ 20–30 days
Flue gas desulphurization (FGD)	~ 18–24 months	~ 30–90 days
Selective Catalyst Reduction (SCR)	~ 5 months	~ 30 days
Selective Non-Catalyst Reduction (SNCR)	~ 4 months	~ 7 days
Low NOx burner, OFA etc.	~ 1 month	~ 15–20 days

FINANCING AND REGULATORY IMPEDIMENTS

Financing for investment required to meet the norms remains one of the main concerns—the investment required and its impact on cost of generation. Uncertainty over the recoverability of cost and time taken for tariff approval were additional concerns. This issue is exacerbated by the weak financial health of discoms which, in turn, has already affected the power generators.

a) The power producers argue that tariff increase could be in the range of Rs 0.5–0.75 per unit; however, HERC calculates (based on actual data from plants) that cost impact will be around 22 paisa per unit.

b) Applications to CERC have requested capex ranging between Rs 1.15 and 2.5 crore/ MW with tariff increase ranging between 45 and 90 paisa per unit. The wide range in the applications shows that it would be very important for regulators to establish clear guidelines. CEA/CERC should give guidance on technology options, pollution control performance and costs benchmarks. While capex is project-specific, broad guidelines will help in assessment and approvals.

c) CERC should devise simplified documentation requirements to streamline in-principle capex and tariff-approval applications. Tariff increases are politically challenging even if permitted under law. Regulators may need to devise mechanism to stagger tariff increases. But, plants need an assured rate increase to help raise financing for the capex and to avoid cash flow problems.

d) CERC believes approval of capex is fundamentally not a problem since it is permitted under 'Change of Law' provisions in PPAs under both Section 62 of Electricity Act, 2003 (Cost Plus) and Section 63 (Competitive Bids). Change in operational parameters such as station heat rate and auxiliary power consumption can be managed.

STATUS UPDATE—NTPC

a. National Thermal Power Corporation (NTPC) has shown commendable leadership in the implementation of new standards. The company expects most plants to meet PM emission standards by 2017.

b. The company also expects to be able to meet the water standard (3.5 m^3/ MWh) in most plants by 2017. In fact, it is planning to go further than the mandate and convert a number of its plants to Zero Waste Discharge.

c. The company has undertaken the detailed engineering assessment for De-SOx and De-NOx. A number of plants are finalizing specifications for tender documents.

d. NTPC will award five pilot projects by December 2016 to assess SCR technology (controlling NOx) for Indian coal. The results will pave the way for the Indian power industry to instal SCR. The company is also confident that its upcoming plants will be able to meet the tightest standards. It is also advising other power plants on assessing technology needs.

RAW MATERIALS

a. Limestone is the key raw material required for FGD. Based on the assumption that only units larger than 500 MW will instal FGD and smaller units can instal partial FGD, around 10–12 million tonnes of limestone is required, which is a small fraction of cement industry's limestone use. Moreover, gypsum (byproduct) produced by the wet FGD process can be used by the construction industry.

b. The De-NOx process will require ammonia or urea particularly for new plants. Currently, both are imported. The annual requirement for ammonia is estimated to be 5 million tonne and for urea 7 million tonnes.

ANNEXURE 1: AGENDA OF THE CONFERENCE

Welcome address Priyavrat Bhati, Programme Director, Centre for Science and Environment	
Overview of challenge and recommendation for regulatory measures Anil Razdan, Retd Secretary, Ministry of Power	
Session 1: Panel discussion on challenges in compliance with the standards Moderated by Chandra Bhushan, Deputy Director General, CSE	
Summary of challenges and impediments; Progress report on installation plans	Mr Ashish Basu, Chairman, Association of Power Producers (APP)
Constraints faced by power stations specially private plants and potential solutions	Sanjay Sagar, Jt Managing Director & CEO, JSW Energy Limited
State-owned plants' perspectives with a focus on challenges for plants in pipeline	Mr M.K.V. Rama Rao, Managing Director, HPGCL
Challenges faced by NTPC and overview of their plans for existing and pipeline plants	Mr Alind Rastogi, Executive Director, NTPC Ltd
Issues for coastal and old power stations and recommendations	Ms Taruna Saxena, Group Head—Corp, Env. & Climate Change, Tata Power
Captive power station's concerns	Mr Razack Baig, Sr Vice President (Project), Ultratech Cement Ltd
Session 2 : Regulatory approvals—capex, tariff, etc.	
Mechanisms to expedite tariff revision petitions	S.C. Srivastava, Chief Engineer, Central Electricity Regulatory Commission
Challenges faced by SERC—cross subsidy, cost recovery etc., tariff petitions	M.S. Puri, Member, Haryana State Electricity Regulatory Commission
	A.K. Das, Member, Orissa State Electricity Regulatory Commission
Session 3: Equipment availability	
Technology availability and applicability for Indian coal power stations	K. Rajavel, Corporate Advisor, Mitsubishi Hitachi Power Systems
FGD solutions to meet the 600 mg/Nm^3 SO_X norms.	Ajith Apte, Managing Director, Transparent Technology
ASCR or HYBRID De-Nox Technology	K. Viswanathan, Head—Engineering, ISGEC Heavy Engineering Limited
Session 4: Ensuring raw material availability and waste management	
Overview: Raw material availability and waste management	Alind Rastogi, Executive Director—Environment, NTPC
Limestone availability for FGD and managing waste	Razack Baig, Sr Vice President (Project), Ultratech Cement Ltd
Supply constraints: Urea availability for coal power stations	Dr S. Nand, Deputy Director General, Fertilizers Association of India
Liquid ammonia handling: regulatory approvals	R.A. Gujar, Dy Chief Controller of Explosives, Petroleum and Explosives Safety Organization
Catalyst management	B. Krishnakumar, General Manager, ISGEC
Session 5: Way forward	
Investment requirements, funding sources	Himanshu Gupta, Sales Director, GE India
Financing mechanisms	Mr Sabyasachi Majumdar, Senior Vice-President, ICRA Limited
CSE's perspective	Chandra Bhushan, Deputy Director General, CSE

ANNEXURE 2: LIST OF PARTICIPANTS

Name	Designation	Organization
Mr M.S. Puri	Member	Haryana Electricity Regulatory Commission
Ms Suman Jain	Group Head	Isgec Heavy Engineering Ltd
Mr Vijay Chaudhry	SBU Head	Thermax Limited
Mr Ashis Basu	CEO-Corporate	GMR Energy Limited
Mr Ajit U. Apte	Managing Director	Transparent Technologies Private Limited
Mr Partha Kundu	General Manager/ Sales & Marketing	KC Cottrell India Pvt. Ltd
Mr Abhishek Chatterjee	Asst. Director General	Association of Power Producers
Mr Avadhesh B Jaiswal	Executive Engineer	Gujarat State Electricity Corporation Ltd
Mr Charat Hora	Regional General Manager-BD	Black & Veatch Private Limited
Mr Bijan Mishra	Sr. Vice President- Environment	Reliance Power Limited
Mr S C Shrivastava	Chief Engineering	Central Electricity Regulatory Commission
Mr A K Das	Member	Odisha Electricity Regulatory Commission
Mr. S.K. Puri	General Manager/O & M	Punjab State Power Corporation Ltd
Mr Mohit Bhargava	General Manager	NTPC Limited
Mr J.P. Debroy	Dy. General Manager—Corporate Operation Services	JSW Energy Limited
Mr P.R. Ekambaram	Superintending Engineer	Telangana State Power Generation Corporation Ltd
Mr Devdatt M. Shukla	Superintending Engineer	Gujarat State Electricity Corporation Ltd
Dr K.V. Reddy	Vice President & Corporate Head-Environment	UltraTech Cement Limited
Mr Razack Baig	Vice President & Head- Power Projects	Ultra Tech Cement Limited
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Mr Suraj Chaudhry	Sr. Manager Sales and Proposals Power Service	Doosan Power systems India Pvt Ltd
Mr Anil Razdan	Retd. Power Secretary	
Mr Mahendra P Patil	Vice President—Sales & Marketing	Transparent Technologies Private Limited
Mr Probal Chatterjee	Sr. Gen. Manager	JK Lakshmi
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Mr Souvik Dutta	General Manager	CESC Limited
Mr G.J. Despande	Director-Technical	JSW Energy Limited
Mr Piyush Goyal	Head—Corporate Advocacy	The Tata Power Company Limited
Mr M. Farrukh Aamir	Specialist—Corporate Regulations	The Tata Power Company Limited
Mr S. Laxmi Narayana	Superintending Engineer	Telangana State Power Generation Corporation Ltd
Mr K. Rajavel	Corporate Advisor	Mitsubishi Hitachi Power systems Ltd
Mr Sanjay Moza	Sr General Manager	Mitsubishi Hitachi Power systems Ltd
Mr Asheesh Agarwal	Senior Market Advisor	Royal Norwegian Embassy
Mr B. Krishna Kumar	General Manager—Marketing / Proposal/ Estimation	Isgec Heavy Engineering Ltd
Mr Richard Budin	Managing Director—Head of Operations	Yara Environmental Technologies AB
Mr K.Viswanathan	Head Engg (Utility Boilers)	Isgec Heavy Engineering Ltd
Mr Sandeep Singh	Senior Manager—Marketing	Andritz India Pvt. Ltd
Mr A.K. Pmysty		GMR Energy Limited
Mr Harish Upperla	Executive—Air pollution control	Andritz India Pvt. Ltd
Ms Taruna Saxena	Group Head-Corp. Environment & Climate Change	The Tata Power Company Limited
Mr Randhir Singh		PSPCL Patiala
Mr Atsushi Kato	Deputy General Manager	Mitsubishi Hitachi Power systems Ltd
Mr Sanjay Sagar	Jt MD & CEO	JSW Energy Ltd
Mr Jaishankar Balan	Senior Manager	JSW Energy Ltd
Dr S.K. Jain	Additional General Manager	NTPC Ltd
Dr A. Rastogi	Executive Director—Environment	NTPC Ltd
Mr Anand B. Rao	Associate Professor	IIT Bombay
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United States
Environmental Protection
Agency

March 2008
EPA530-F-08-009
www.epa.gov/osw

Agricultural Uses for Flue Gas Desulfurization (FGD) Gypsum

What Is Gypsum?

Gypsum is calcium sulfate dihydrate, or $CaSO_4 \cdot 2H_2O$, which can come from a number of sources. Mined gypsum is a common mineral found around the world in sedimentary rock formations, from which it is mined or quarried. FGD gypsum is a synthetic material of identical chemical structure produced as a byproduct from coal-fired electric utilities. Other sources of gypsum include phosphogypsum, citrogypsum and fluorogypsum, which are byproducts of different chemical manufacturing processes[1].

Gypsum has many beneficial uses, including agricultural applications, wallboard products for residential and commercial buildings, as an ingredient in portland cement manufacturing, and as a filler ingredient in some foods and toothpaste. Because of its relatively high degree of purity, FGD gypsum can be used as a substitute for mined gypsum in many uses, while also realizing important environmental benefits that result from recycling this byproduct material.

Gypsum in Agriculture

Both mined and FGD gypsum can be used as a soil amendment in a range of soil and hydrogeologic conditions. Gypsum can be used as a nutrient source for crops; as a conditioner to improve soil physical properties, and water infiltration and storage; to remediate sodic (high sodium) soils; and to reduce nutrient and sediment movement to surface waters, among other uses. The United States Environmental Protection Agency (USEPA) and the United States Department of Agriculture (USDA) support the use of FGD gypsum in appropriate soil and hydrogeologic conditions as an effective method of soil conservation and industrial material recycling. However, before applying any fertilizer or other soil amendment, including FGD gypsum, it is important to first assess the amendment material and soil conditions to determine compatibility and appropriate application rates.

1 This brochure does not address these sources of gypsum.

FGD Gypsum

FGD gypsum is created by forced oxidation scrubbers attached to coal-fired power plants to limit emissions of the sulfur which is released when coal is burned. The scrubbers spray liquid lime or limestone slurry into the flue gas path, where it reacts with sulfur in the gas to form calcium sulfite, an intermediate product with little practical value. However, when the chemical reaction is pushed further by the introduction of air into the FGD absorber tank, the calcium sulfite reacts to become gypsum. The material is then dewatered and processed; the end product is a consistent, finely divided powder. This process is known as flue gas desulfurization (FGD), and the gypsum produced is known as FGD gypsum.

The term FGD gypsum is the name most often used by generators of the material. Other names include recaptured gypsum, byproduct gypsum, and synthetic gypsum. All of these terms refer to the same material produced by the forced oxidation process. The gypsum in both FGD gypsum and mined gypsum has the same basic chemical makeup— $CaSO_4 \cdot 2H_2O$; however, the amount and types of trace materials and unreacted sorbents found in the gypsum can vary among power plants and among mines[2]. If you are considering using FGD gypsum products as a soil amendment, it is appropriate that the chemical analysis of the material be provided by all commercial sources to support decision-making in their use, as States may have regulations and standards that need to be followed. To this end, it is advisable to contact your State's department of agriculture or State extension service before FGD gypsum is used as a soil amendment.

The Future of FGD Gypsum

According to the American Coal Ash Association's annual Coal Combustion Product Production and Use Survey, total production of FGD gypsum in 2006 was approximately 12 million tons. Close to 9 million tons of FGD gypsum was put to beneficial use, while the remainder was landfilled. Of the amount used, approximately 80 percent was used in wallboard products, and about 2 percent (168,190 tons) was used in agriculture, with most of the rest being used in concrete and cement applications. In the future, FGD gypsum may find more use as filler in plastics and fiberglass, as well as in reducing mine subsidence, re-contouring landforms, and improving soil conditions at mining sites.

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2 Information about constituent concentrations in mined and FGD gypsum may be found at http://www.epa.gov/epaoswer/osw/conserve/c2p2/ccps/fgd.htm.

Over the next ten years, annual production of FGD gypsum may double as more coal-fired power plants come online, and as scrubbers are added to existing power plants to comply with the EPA's Clean Air Interstate Rule and other requirements. It is anticipated that the majority of the new scrubbers will produce FGD gypsum, although in some parts of the country power plants may select dry scrubbers, resulting in materials other than FGD gypsum. This increased supply is an opportunity to explore the expanded use of FGD gypsum as a soil amendment. Ongoing and future research and demonstration projects will be able to assist people in making decisions about the use of FGD gypsum.

Agricultural Applications of Gypsum

There are three general uses of gypsum in agricultural applications:

- A source of nutrients for plants
- Improvement of soil physical and chemical properties
- Reduction in the transport of nutrients, sediment, pesticides and other contaminants to surface waters

Current Uses of Gypsum in Agriculture

Nutrient Source

Gypsum is rich in calcium and sulfur, two nutrients essential to all crops. The most common application of gypsum is to crops that have high calcium requirements, or to areas that have calcium-poor soils. Peanuts have particularly high calcium requirements, and gypsum often is added to peanut fields to increase yield and quality of the crop. Many fruits, vegetables, and cereals also can benefit from increased calcium availability; in particular, fruits such as tomatoes and cantaloupes need calcium for skin strength, and growers may add calcium to produce fewer blemishes and a longer shelf life.

Sulfur fertilization also is required for many crops, and gypsum can be an effective sulfur source. There is a growing need for sulfur addition to soils, since atmospheric deposition of sulfur has decreased, and most nitrogen and phosphorus fertilizers no longer contain significant amounts of sulfur. Sulfur is sometimes a constituent of nitrogen and phosphorus fertilizers, but gypsum also can be an effective sulfur source for some crops. In addition to calcium and sulfur, gypsum, depending on its source, may provide essential micronutrients to plants.

Soil Improvement

Gypsum is helpful in treating sodic soils and soils suffering from crusting and other structural problems. Gypsum is more readily soluble in water than other calcium-rich soil amendments such as limestone, and therefore moves throughout the soil column more easily. Calcium ions from gypsum displace excess sodium

and other ions, which then become mobile and diffuse. The calcium ions reduce dispersion of soil particles by promoting the aggregation of clay particles. This improves soil structure and stability and prevents soil crusting. Reduced crusting and better particle aggregation allow for greater water infiltration and storage in soil, thereby reducing runoff and erosion. These soil structural improvements also ease the emergence of seedlings and allow roots to penetrate further into the soil to take advantage of the additional stored moisture.

Mitigation of Contaminant Transport to Surface Water

In addition to water quality benefits associated with reduced runoff and erosion, FGD gypsum application can reduce the solubility of nutrients such as phosphorus in livestock and poultry manure and soils treated with manure. Gypsum converts readily soluble phosphorus to less-soluble forms, which can reduce the runoff of phosphorus into adjacent streams, lakes, or ground water. Excess phosphorus in runoff leads to water quality problems, including algal blooms and eutrophication of water bodies.

Gypsum Decisions in Agriculture

Recycling coal combustion products (CCPs) and other industrial materials can result in significant environmental benefits, including reduced greenhouse gas emissions, less use of virgin materials, and decreased use of landfills. The USEPA's Coal Combustion Products Partnership (C2P2) (http://www.epa.gov/epaoswer/osw/conserve/c2p2/) aims to increase recycling of CCPs, including FGD gypsum. In addition to its environmental benefits, FGD gypsum may be less expensive for users than mined gypsum, although transportation costs can be a factor in evaluating the practicality of using FGD gypsum as a gypsum source.

As with any fertilizer or chemical additive, there are a range of considerations that should be kept in mind when deciding whether to apply gypsum. Gypsum is not suitable for all soil types, soil conditions or crops. Appropriate application rates should be determined to accomplish specific soil improvement goals, while not exceeding state limits on the use of individual constituents. In general, application rates of up to two tons per acre should be sufficient to accomplish most agronomic and horticultural objectives[3].

In situations where there is excess sulfur in the soil, the amount of gypsum to be added should be balanced against copper nutrition in animals, as high levels of sulfur in feed can interfere with copper absorption. Boron concentrations in FGD gypsum typically are higher than in natural gypsum sources; therefore, crops sensitive to boron uptake such as cherry, peach and kidney bean may require lower application rates. The high calcium and sulfur content of gypsum can cause an imbalance in other soil nutrients, such as magnesium; therefore, soil nutrient characteristics, and potential plant and animal uptake, of these and other constituents should be understood and considered before deciding whether to use any gypsum product.

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3 Donstova et al. and other sources

In determining the environmental suitability of FGD gypsum for a particular location, you may find the USEPA's Industrial Waste Management Evaluation Model (IWEM) and the chapter on land application (Chapter 7) in the associated *Guide for Industrial Waste Management* (http://www.epa.gov/epaoswer/non-hw/industd/guide/index.htm) to be useful resources. You should also consult with your State's department of environmental protection to comply with any regulations pertaining to the management of CCPs. You may also find it helpful to consult with your State's department of agriculture and agricultural extension service, and with the USDA Natural Resources Conservation Service.

FGD Gypsum Beneficial Use Considerations

Decision	Things to Consider	Resources
1. Is gypsum a good choice for my needs?	• Types of crops • Nutrient requirements of crops • Soil structure • Soil chemical profile	• State department of agriculture/ag. extension agency • USDA Natural Resources Conservation Service
2. If gypsum is a good choice, should I use FGD gypsum?	• Trace element sensitivity of crops • Purity of available FGD gypsum • Cost differential	• State department of agriculture/ag. extension agency • Fertilizer supplier
3. Is the use of FGD gypsum environmentally protective?	• Ground water • Direct exposure • Ecosystem impacts • Surface waters	• State departments of environmental protection • EPA's *Guide for Industrial Waste Management*

References and Websites

The references and Websites below provide additional information and studies about the uses of gypsum in agriculture.

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EPA (2003) *Guide for Industrial Waste Management.* U.S. Environmental Protection Agency. EPA530-R-03-001. February.

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Stout, W.L., J.L. Hern, R.F. Korcak, and C.W. Carlson (1988) *Manual for Applying Fluidized Bed Combustion Residue to Agricultural Lands*. RS-74. U.S. Department of Agriculture, Agricultural Research Service, Washington, DC.

USGS (2005) *Major- and Trace-Element Concentrations in Soils from Two Continental-Scale Transects of the United States and Canada*. Open-File Report 2005-1253, U.S. Geological Survey. Available online at: http://pubs.usgs.gov/of/2005/1253/. Accessed September 13, 2007.

For More Information

--USDA Natural Resources Conservation Service:

http://www.nrcs.usda.gov/partners/for_farmers.html

--USEPA C2P2 Website: http://www.epa.gov/epaoswer/osw/conserve/c2p2

--USEPA Industrial Waste Management Website:

http://www.epa.gov/epaoswer/non-hw/industd/guide/index.htm

--FGD Products Website: http://www.fgdproducts.org/

--Information sheets on agricultural gypsum use from a leading distributor:

http://www.gypsumsales.com/gyp_whitepapers.html

--A paper on agricultural gypsum use from a distributor:

http://www.dktgypsum.com/news_content7.html

--Information sheet on FGD gypsum from the American Coal Ash Association: http://www.acaa-usa.org/PDF/EnvFocusFinal3g2.pdf

Acknoweldgements

EPA gratefully acknowledges the following organizations for their contributions to its preparation:

-- United States Department of Agriculture
-- Agricultural Research Service
-- United States Department of Energy--National Energy Technology Laboratory
-- USEPA Office of Air and Radiation
-- USEPA Office of Research and Development
-- American Coal Ash Association
-- Electric Power Research Institute

Coal Combustion Residual Beneficial Use Evaluation: Fly Ash Concrete and FGD Gypsum Wallboard

February 2014

Final

United States Environmental Protection Agency
Office of Solid Waste and Emergency Response
Office of Resource Conservation and Recovery

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Executive Summary

Purpose

The goal of this document is to use sound science based on accepted and standard practices to determine whether the United States Environmental Protection Agency ("EPA" or "the Agency") should support the beneficial use of coal fly ash in concrete and flue gas desulfurization (FGD) gypsum in wallboard. Coal fly ash used as a direct substitute for portland cement in concrete (hereafter referred to as "fly ash concrete") and FGD gypsum used as a replacement for mined gypsum in wallboard (hereafter referred to as "FGD gypsum wallboard") are the two largest encapsulated beneficial uses of coal combustion residuals (CCRs) in the United States.

In addition, this document provides an example of how to conduct similar analyses using EPA's *Methodology for Evaluating Encapsulated Beneficial Uses of Coal Combustion Residuals* (US EPA, 2013a). This example also demonstrates an appropriate level of documentation for such analyses.

Conclusions

Based on the analysis set forth in this document, the evaluation concludes that environmental releases of constituents of potential concern (COPCs) from CCR fly ash concrete and FGD gypsum wallboard during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors.

The beneficial use of CCRs, when conducted in an environmentally sound manner, can contribute significant environmental and economic benefits. Environmental benefits can include reduced greenhouse gas emissions, reduced need for disposing of CCRs in landfills, and reduced use of virgin resources. Economic benefits can include job creation in the beneficial use industry, reduced costs associated with CCR disposal, increased revenue from the sale of CCRs, and savings from using CCRs in place of other more costly materials.

Based on the conclusion of the analysis in this document stated above, and the available environmental and economic benefits, EPA supports the beneficial use of coal fly ash in concrete and FGD gypsum in wallboard. The Agency believes that these beneficial uses provide significant opportunities to advance Sustainable Materials Management (SMM).

Background

Beneficial use of industrial materials has the potential to provide economic benefits, preserve virgin resources, and avoid negative environmental impacts associated with the acquisition and processing of virgin materials. Beneficially using these materials presents significant opportunities to advance SMM and the Agency's SMM Program. The SMM Program supports the productive and sustainable use/reuse of resources throughout all stages of their lifecycles, from resources acquisition through disposal. The SMM Program seeks to avoid or minimize impacts to the environment while accounting for economic

efficiency and social considerations. CCRs are one of the industrial materials produced in the greatest quantity each year. The beneficial use of CCRs when conducted in a manner protective of human health and the environment can advance these SMM goals.

While the beneficial use of CCRs has been shown to have economic and material benefits, the environmental impacts associated with their use must also be considered. To do this, EPA's Office of Solid Waste and Emergency Response (OSWER) developed the *Methodology for Evaluating Encapsulated Beneficial Uses of Coal Combustion Residuals* (US EPA, 2013a). While in this document the Agency has used the methodology to evaluate the beneficial use of CCRs in certain encapsulated uses, this methodology can be useful to states, tribes, local governments, the public, and the regulated community for making informed decisions about any encapsulated beneficial uses of CCRs. The methodology has undergone an independent external letter peer review. A summary of the comments received from peer reviewers is available in the document *Peer Review Summary Report: Independent External Peer Review of the Preliminary Draft Report Methodology for Evaluating Encapsulated Beneficial Uses of Coal Combustion Residuals* (US EPA, 2012a). Responses to these comments are available in the document *Responses to External Peer Review Comments: Methodology for Evaluating Encapsulated Beneficial Uses of Coal Combustion Residuals* (US EPA, 2013b).

The methodology establishes a series of five steps that can be used to determine whether environmental releases of COPCs from an encapsulated beneficial use product made with CCRs are comparable to or lower than those from an analogous product made without CCRs, or are at or below relevant regulatory and health-based benchmarks developed for human and ecological receptors, during use by the consumer. The methodology allows evaluation of the range of possible encapsulated beneficial uses for any CCR. As developed, the methodology is quite flexible. The party conducting the evaluation can choose to begin at the first step and follow the methodology in the order presented or, based on the type and amount of data available on the CCR and corresponding product, can choose to begin the evaluation at any other step of the methodology. If releases of COPCs from the CCR beneficial use are found to be comparable to or lower than those from an analogous non-CCR product, or are at or below relevant regulatory and health-based benchmarks at any step of the methodology, then no further evaluation is necessary for those particular COPCs.

Summary of the Analysis

The Agency used the methodology to evaluate the potential environmental impacts associated with fly ash concrete and FGD gypsum wallboard. These beneficial use products may be variable in their composition. However, this evaluation only addressed those products that meet relevant physical and performance standards established by voluntary consensus standard bodies; that conform to specific design criteria identified in this evaluation (e.g., ≤ a 40 percent fly ash replacement rate); and that incorporate fly ash and FGD gypsum from common pollution control devices used in the United States. This evaluation also did not address products that contain additional additives or industrial materials that may alter releases from the products. In this specific evaluation, the Agency began with the first step and followed subsequent steps in the order presented in the methodology. The findings at each step of this specific conservative evaluation are summarized below.

Step 1 (Literature Review and Data Collection): From the available literature, the evaluation identified the following releases that may occur during use of fly ash concrete and FGD gypsum wallboard: 1) generation of dust, 2) emanation to air, 3) leaching to ground and surface water, and 4) decay of naturally occurring radionuclides (also referred to simply as radioactive decay). In addition, this literature review found several existing evaluations to be of sufficient applicability and quality to rely upon in the current evaluation. For fly ash concrete, the findings from these evaluations were used to eliminate radioactive decay from further consideration. For FGD gypsum wallboard, the findings from these existing evaluations were used to eliminate all releases from further consideration, except for emanation to air. The evaluation then used the available literature to identify COPCs for each of the remaining releases.

Step 2 (Comparison of Available Data): The Step 2 evaluation used the data identified in Step 1 to compare releases from fly ash concrete and FGD gypsum wallboard to releases from their respective analogous products (i.e., portland cement concrete and mined gypsum wallboard) during use by the consumer. The evaluation found that concentrations of silver and manganese in dust from fly ash concrete were comparable to or lower than those in dust from portland cement concrete. The evaluation also found that concentrations of arsenic, cadmium, lead, molybdenum, and thallium in leachate from fly ash concrete and portland cement concrete were comparable. Therefore, the evaluation did not carry these COPCs forward for further consideration, but retained all other COPCs from fly ash concrete and FGD gypsum wallboard for further consideration.

Step 3 (Exposure Review): The Step 3 evaluation reviewed the releases carried forward from Step 2 to identify exposures that may occur during use of the product. Where multiple exposure pathways associated with a given release were identified, the evaluation retained only those pathways likely to drive exposures for further consideration. The evaluation did not eliminate any releases or associated COPCs at this step.

Step 4 (Screening Assessment): The Step 4 evaluation conducted a screening assessment for each exposure pathway carried forward from Step 3 of the evaluation. The evaluation used conservative (i.e., likely to overestimate exposures) environmental, fate and transport, and exposure data to estimate COPC exposures that may occur during use of the CCR beneficial use products. The evaluation then compared these conservative exposure concentrations to relevant screening benchmarks to determine whether to conduct more in-depth evaluation. At the end of this step, the evaluation found that all remaining COPCs were below relevant screening benchmarks. Therefore, this evaluation did not proceed to the final Step 5 (Risk Assessment).

Conclusion: At the end of Step 4 the analysis was concluded as all identified COPCs had been eliminated in Steps 1 through 4. Thus, based on application of the methodology and the lines of evidence set forth in this document, the evaluation concludes that environmental releases of COPCs from CCR fly ash concrete and FGD gypsum wallboard during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors.

SCR DESIGN PROCESS

Design Inputs

- DeNOx criteria - % of NOx to remove
- Operating period – 16,000/24,000 hr
- Flue gas flow conditions
  - Flow rate
  - Temperature
  - Pressure
  - Composition (NOx inlet, O2, H2O, SO2/SO3)
- Allowable NH_3 slip
- Catalyst geometry/composition

Considerations

- Reactor configuration/space, flow distribution
- Coal type/specs, ash load
- Catalyst deactivation
- SO_2 to SO_3 oxidation
- Allowable pressure drop

Design Outputs

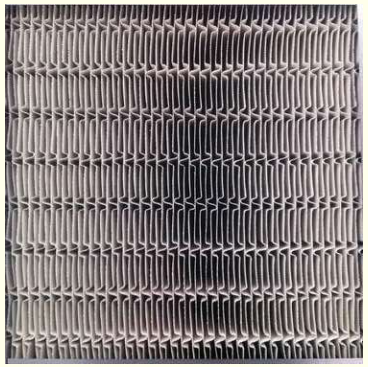
- Catalyst volume
- Catalyst activity
- SO_2 to SO_3 oxidation rate
- Pressure drop
- Design margin (safety factor)

SCR CATALYST

- The primary base material of catalyst is titanium dioxide (TiO_2), with smaller amounts of other metal oxides including tungsten oxide (WO_2) for thermal support and vanadium pentoxide (V_2O_5), which is the primary active material.
- Two predominant styles of catalyst are used in SCRs - honeycomb and plate type.
- Honeycomb catalyst provides the greater surface area of the two designs, but can be susceptible to fly ash fouling.
- BHEL has capability to manufacture both honey comb as well as plate type catalysts

HONEY COMB

PLATE TYPE



COMPARISON OF SCR REAGENT INJECTION SYSTEMS

Anhydrous Ammonia	Aqueous Ammonia (19 or 29% by weight NH_3)	Urea to Ammonia
Lowest capital cost	Moderate capital cost	Highest capital costs
Lowest operating cost	High energy usage	Moderate energy consumption
Fewest product deliveries	Largest number of product deliveries	Moderate product deliveries
Highest safety risk	Lower risks than anhydrous	Lowest safety risk
Highest permitting costs	Moderate permitting issues	Lowest permitting issues
Largest number of regulatory issues	Moderate regulatory issues	Lowest regulatory issues

IN HOUSE CAPABILITY OF BHEL

IN HOUSE CAPABILITY OF BHEL

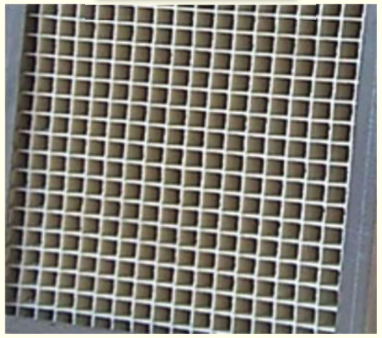
Catalyst Design Strategy for high Ash content coal

- ❑ Proper Geometry (Shape & Pitch) to Pass Ash
- ❑ Sized to Accommodate Deactivation
- ❑ Protective erosion resistant honeycomb layer
- ❑ Mechanical stability (ceramic fibre reinforcement)

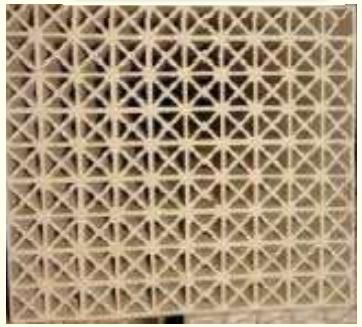
In-house capability at BHEL's Ceramic Technology Institute, Bangalore

- ❑ Expertise to design & fabricate honeycomb die
- ❑ Enable realizing quickly new shape & pitch of honeycomb as needed based on computational reactive mechanics analysis – manufacturing protected by national and international patents
- ❑ CTI developed erosion resistant honeycomb layer protecting the catalysts downstream

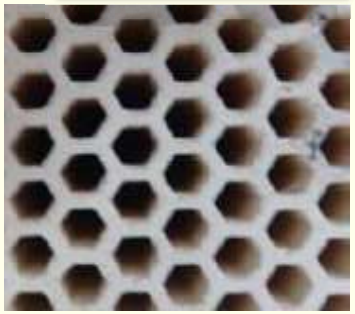
SQUARE



DIAGONAL



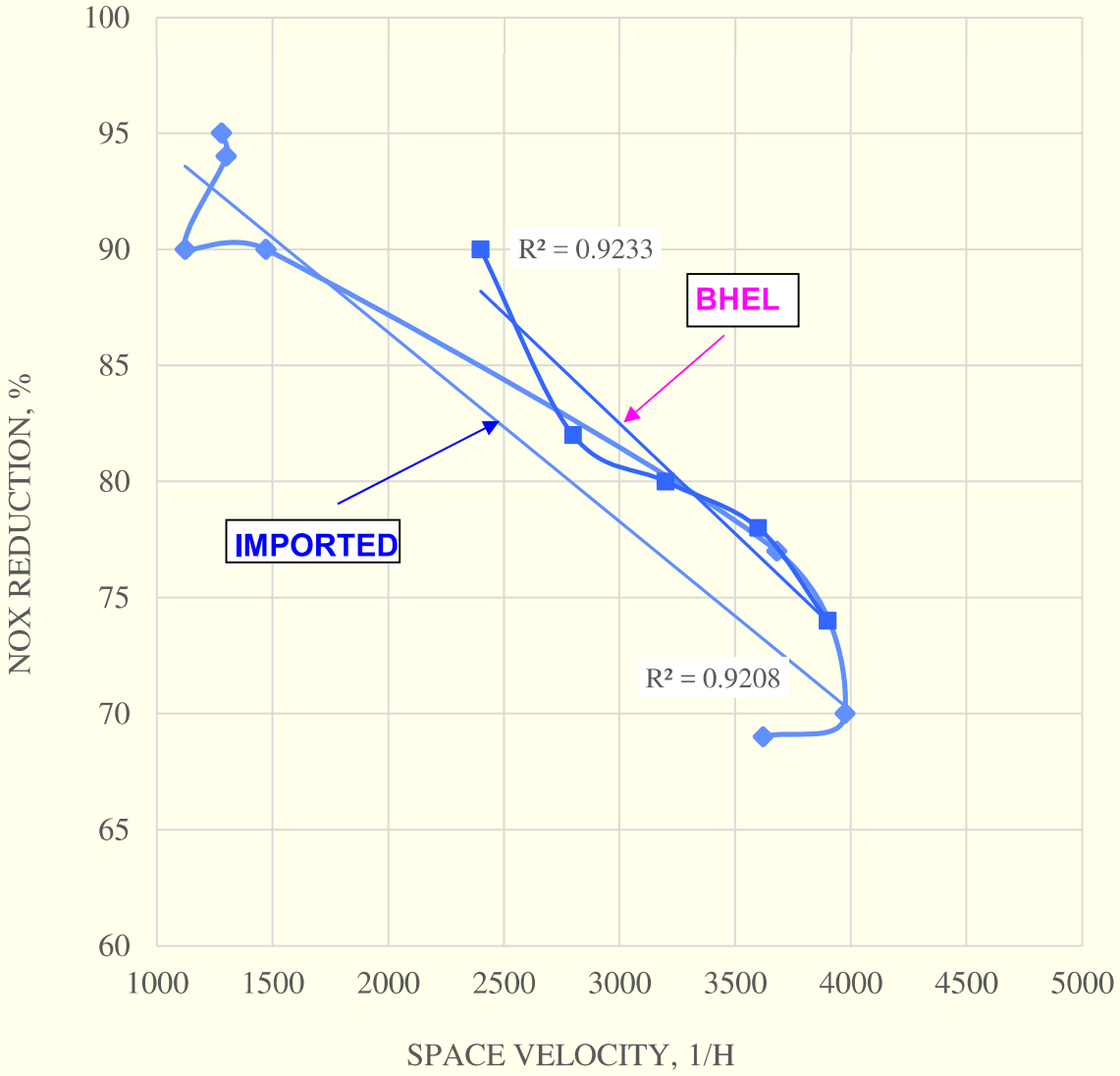
HEXAGONAL



TEST RESULTS OF SCR CATALYSTS AT FETF

S.No	SPACE VELOCITY h^{-1}	AVG. FLUE GAS TEMPERATURE IN °C	NO_x REDUCTION %	
			BHEL Catalyst	Imported Catalyst
1	1100	330	-	90
2	1280	350	-	95
3	1500	335	-	90
4	2300	350	86	85
5	2670	340	90	88
6	3010	350	86	80
7	3680	335	88	78
8	3735	330	77	74
9	3780	360	78	72
10	3975	290	73	70

SCR CATALYST EVALUATION IN FETF



KEY FINDINGS FROM PILOT SCALE TESTING AT FETF

- Experiments carried out with imported as well as BHEL developed catalyst. The NOX reduction by SCR system in both the cases was in the range of 80 to 95%.
- The optimum flue gas temperature was found to be around 350°C. Maintaining operating temperature between 300 to 400 ^{0}C ensures higher NOx reduction efficiency. This also prevents Maintaining lower temperature limits leads to deposition of ammonium bi-sulphate while higher temperature limits favour SO_2 to SO_3 oxidation.
- Tests were carried out using gaseous Ammonia as well as liquid Ammonia of 25% concentration. The NOX reduction was comparatively better with the usage of gaseous ammonia due to uniform mixing.
- No plugging of fly ash particle in catalyst cells was found, during initial 100 hours of SCR operation when using coal with 40% ash content.
- Ammonia slip was less than 5 ppm.

Draft National Electricity Plan

(Volume 1)

Generation

[In fulfilment of CEA's obligation under section 3(4) of the Electricity Act 2003]

Government of India

Ministry of Power

Central Electricity Authority

DECEMBER, 2016

Table 5.13

Capacity addition during 2022-27 (Base Case)

(All figures in MW)

FUEL TYPE	Capacity addition during 2022-27
Hydro*	12,000
Thermal	44,085
Coal	44,085
Gas	0
Nuclear	4,800
Sub Total (Conventional)	**60,885**
Wind	40,000
Solar	50,000
Bio Mass	7,000
Small Hydro Plants	3,000
Sub Total (RES)	**100,000**
Total Capacity Addition	**1,60,885**

*** excludes 21,600 MW imports from hydro plants of neighbouring countries.**

The projected coal based capacity addition requirement during the period 2022-27 is 44,085 MW considering no coal based capacity addition during 2017-22 Table 5.7(a).

Studies indicate that a coal based capacity of 44,085 MW is required during the period 2022-27 with no coal based capacity addition requirement during the year 2017-22. Now a coal based capacity of 50,025 MW is already under construction which likely to yield benefits during 2017-22. Therefore, this excess coal based capacity would fulfil the capacity requirement for the years 2022-27.

5.14 ADDITIONAL SCENERIO FOR THE YEARS 2022 – 27

Study has been carried out for capacity addition requirement during the years 2022-27, considering low hydro capacity addition of 11,788 MW in the years 2017-22 and 5,000 MW during the years 2022-27.

The details of coal based capacity addition requirement for the years 2022-27 in this scenario are shown in **Table 5.15**.

Table 5.15

Capacity addition required during 2022-27 in Low Hydro scenario

(All figures in MW)

TYPE	Capacity addition during 2022-27
Conventional	
Hydro*	5000
Thermal	50,025
Coal	0
Gas	50,025
Nuclear	4,800
Sub Total (Conventional)	**59,825**
Renewables	
Wind	40,000
Solar	50,000
Other RES	10,000
Sub Total (Renewables)	**1,00,000**
Total Capacity Addition	**1,59,825**

*** excludes 21,600 MW imports from hydro plants of neighbouring countries.**

It can be seen that in low hydro scenario, coal based capacity requirement has increased from 44,085 MW **(Table 5.12)** to 50,025 MW.

Studies indicate that a coal based capacity of 50,025 MW is required during the period 2022-27 with no coal based capacity addition requirement during the year 2017-22. Now a coal based capacity of 50,025 MW is already under construction which likely to yield benefits during 2017-22. Therefore, this excess coal based capacity would fulfil the capacity requirement for the years 2022-27.

b) DURING THE YEARS 2022-27

i) Priority has been accorded towards development of hydro and nuclear based projects which are already likely to get commissioned in the year 2022-27. Hydro capacity addition of 12,000 MW based on the projects concurred by CEA has been considered during 2022-27. Nuclear capacity of 4,800 MW during 2022-27 has been considered for planning studies as per the information furnished by DOAE. No new gas based power plants has been considered during 2022-27 in view of acute natural gas shortage in the country. Import from neighbouring countries to the tune 21,600 MW has been considered for the studies.

ii) The study result for the period 2017-22 indicated that no coal based capacity addition is required. Considering this as input for the studies for the period 2022-27 and committed capacity addition of Nuclear -4,800 MW, Hydro-12,000 MW and RES 100,000 MW during 2022-27 and demand projections for the year 2026-27, study for the period 2022-27 reveals that a coal based capacity addition of 44,085 MW is required. However, as coal based capacity of 50,025 MW is already under construction which is likely to yield benefits during 2017-22, this coal based capacity would fulfil the capacity requirement for the years 2022-27.

iii) It is expected that the share of non-fossil based installed capacity (Nuclear + Hydro + Renewable Sources) will be increased to 46.8 % by the end of 2021-22 and will further increase to 56.5 % by the end of 2026-27 considering capacity addition of 50,025 MW coal based capacity already under construction and likely to yield benefits during 2017-22 and No coal based capacity addition during 2022-27.

iii) Study for the period 2022-27 has also been carried out by considering low hydro capacity addition of 11,788 MW in the years 2017-22 (plants already under construction) and 5,000 MW during the years 2022-27. Study reveals that a coal based capacity addition of 50,025 MW is required. However, as coal based capacity of 50,025 MW is already under construction which is likely to yield benefits during 2017-22, this coal based capacity would fulfil the capacity requirement for the years 2022-27 even in case of low hydro scenario.

(5) THERMAL

i) India is now making a transition from power deficit to power surplus scenario.

ii) Avenues of exports of surplus power available in the Indian Grid to the SAARC countries need to be vigorously explored and pursued.

iii) A significant percentage of generating plants in the country is well past their useful life. They also contribute significantly to environmental pollution. CEA/MoP may undertake a comprehensive study to identify these units and draw up a time bound action plan for retirement of these inefficient and old units in consultation with the State Governments/ stakeholders.

iv) Retrofitting of the existing thermal plants for increased ramping capacity and backing down capacity must be explored in view of integration of RES.

v) Thermal plant in the vicinity of a city may explore the possibility of using treated sewage water from municipalities/corporations. Proper assessment of requirement of water by the power plants and availability of treated water from sewage need to be made for this purpose.

vi) India is now having manufacturing capability of power plants related equipment to the extent of 20,000 MW per year. With the infusion of high quantum of RES into the grid, this full capacity may not be utilized by meeting the internal demand of the country. To ensure full utilization of capacity, the manufacturing companies may explore the possibility of exporting the equipment to other countries. This shall be consistent with the "Make in India" policy of the Government of India.

vii) To accommodate high quantum of RES into the grid, thermal plants are likely to run at low PLF in future. Many plants may get partial/nil schedule of generation. The market mechanism through regulatory intervention needs to be evolved so that the owners of thermal plants are able to recoup the investment and at the same time, customers are not unnecessarily burdened with high tariff.

viii) The electricity grid is undergoing rapid transformation in terms of net load characteristics after accommodating the variability of RES. Conventional power plants must have rapid ramping and backing down capability. It is proposed that the ramping and backing down characteristics of different categories of conventional generating units are spelt out in the CEA standard. A conventional unit should demonstrate its ramping and backing down capability before it is declared under commercial operation.

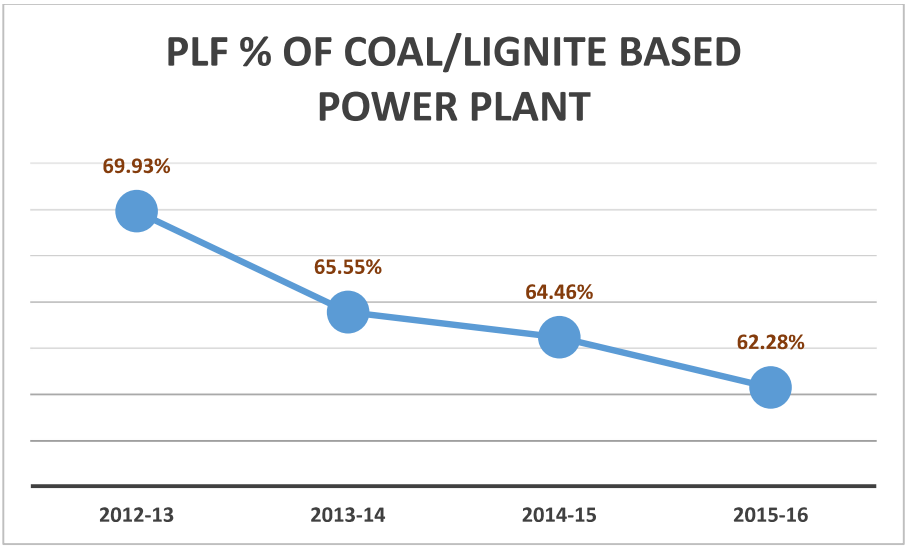
ix) To harness the balancing potential of the existing power plants, it is essential to develop market mechanism through regulatory intervention. The market must provide proper price signal to the potential stakeholders in the grid to willingly participate in the balancing market.

x) Gas based power stations are best suited after hydro power plants (including PSPs) for providing balancing requirements of the grid due to integration of RES. Therefore, adequate gas should be made available for effective utilization of existing gas based stations.

1.2.4 Plant Load Factor of Coal/Lignite Based Power Plant

The national average Plant Load Factor (PLF) of Coal based power generating stations during last four years i.e. 2012-13, 2013-14,2014-15 and 2015-16 is 69.93% ,65.55%, 64.46% and 62.28% respectively. The year wise PLF is shown in **Exhibit 1.5**

Exhibit 1.5



1.2.5 Annual System Load Factor

The Annual System Load Factor is the ratio of the energy availability in the system to the energy that would have been required during the year if the annual peak load met was incident on the system throughout the year. This factor depends on the pattern of Utilization of different categories of load. The Annual System Load factor has remained close to 84% since 2011-12, primarily because of prevailing energy shortages in the system and the load staggering measures adopted in the various states particularly in agriculture sector. Annual Electric Load Factor is as depicted in the **Exhibit 1.6.**

CHAPTER 9

COAL REQUIREMENT

9.0 INTRODUCTION

Fuel is the key input required to be tied up before implementation and proper operation of the thermal power plants. In the changed scenario with growing concern on environment, Government has given emphasis on Renewable Energy projects. However, Country's reliance on coal based generation cannot be overlooked. An important aspect which, therefore, needs to be addressed is the availability of adequate coal to fuel the generation of power. In order to optimize coal usage, Government is committed for super critical/ ultra-super critical technology which are much more efficient and results into reduction in usage of coal. The timely availability of all the key inputs including fuel would ensure timely completion of the project and therefore avert detrimental implications of cost and time overruns in case the power project is delayed.

This Chapter broadly deals with a review of fuel availability during the 12th Plan, an assessment of requirement of fuel for the period 2017-22 & indicative requirement of the coal for the period 2022-27 as well as critical issues which need to be addressed and constraints being experienced in the coal sector. This would give a broad scenario to all the associated stakeholders to enable them to take advance action and plan their production targets etc.

9.1 COAL SUPPLY SCENARIO

9.1.1 Background

Coal is the mainstay of India's energy sector. The All India Installed Capacity of the country is about 302,088 MW as on 31.03.2016, out of which about 185172.88 MW (61.3%) is coal based. Of the total power generated in the country, 77.8 % comes from coal based thermal power stations even though they constitute only 61.3% of the total installed capacity. Once the power station is commissioned, the biggest challenge is to operate the station at a high plant load factor (PLF), which is a measure of the output of a power plant compared to the maximum output it could produce. Higher load factor usually means more output and a lower cost per unit of electricity generation. Performance of the power plant is measured on the basis of PLF and Station Heat Rate. However, the Plant Load Factor (PLF) of the thermal power stations in the country has been decreasing steadily over the years. The PLF has decreased from 78.9 % in 2007-08 to 62.0% in 2015-16.

WCD Thematic Review
Options Issues Series IV.1

Electricity Supply and Demand Side Management Options

Final Version: November 2000

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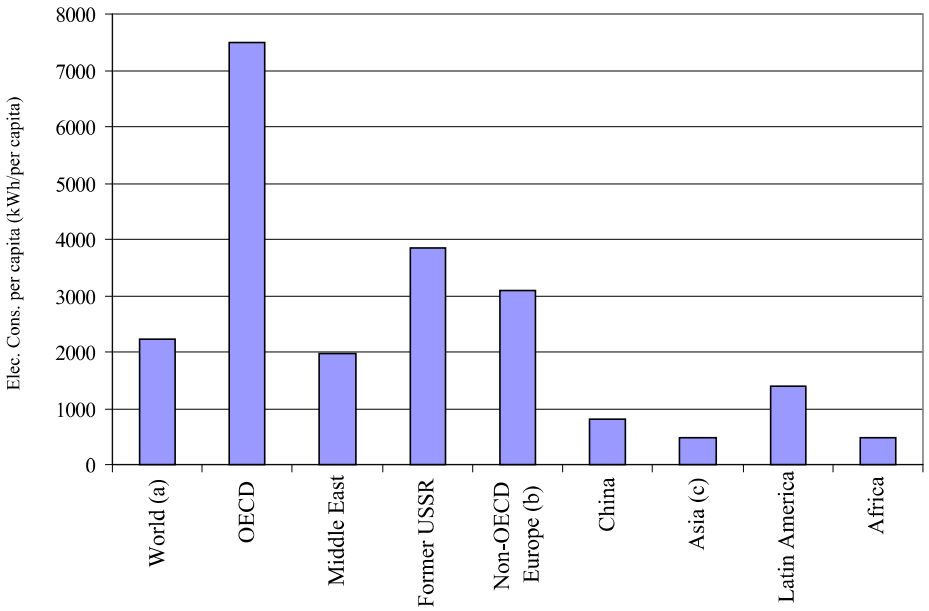
(SOURCE: International Energy Agency (IEA) Energy data.)

Global and regional statistics indicate the average per capita consumption of electricity is 7500 kWh/year in OECD counties as compared to 482 kWh/year in Asia (excluding China, which is 822 kWh/year), 490 kWh/year in Africa, and 1402 kWh/year in Latin America. However, these figures mask variations in the number of people in a particular society with electricity access, and actual use per person, household or industry. This has implications for supply and demand side management strategies and potential in the different settings.

Figure 2.1 Variations in Electricity Consumption per Capita by World Regions (1996)



(a) World excludes Albania, DPR of Korea and Vietnam.
(b) Non-OECD Europe excludes Albania.
(c) Asia excludes China, DPR of Korea and Vietnam.

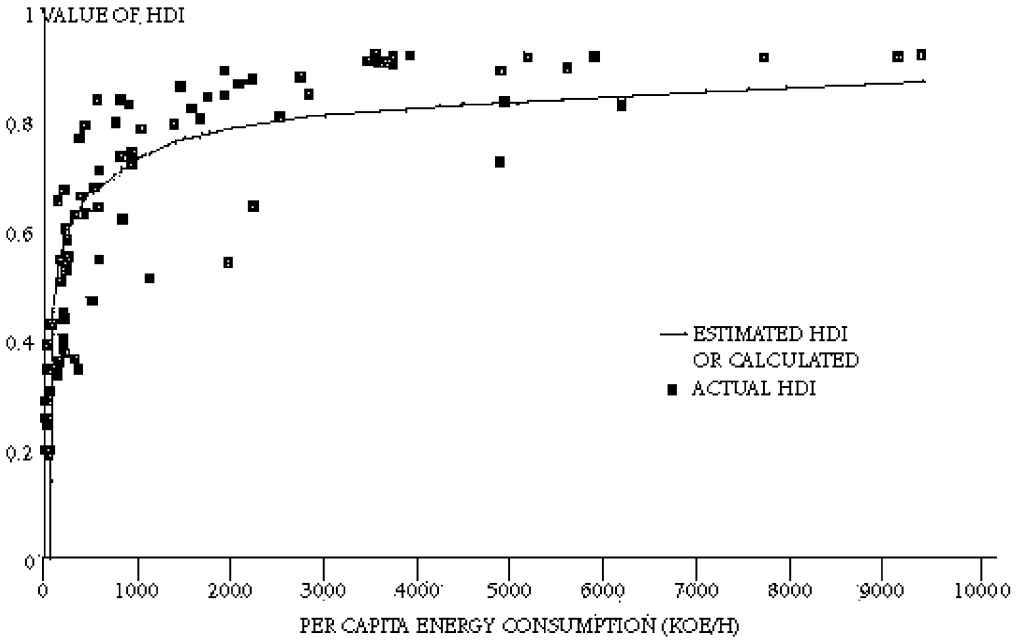
*Gross production + exports – transmission /distribution losses.
**CO2 emissions from fuel combustion only. Emissions are calculated using IEA's energy balances and the Revised 1996 IPCC Guidelines.
(SOURCE: IEA Energy data.)

2.2.2 Energy and Electricity Consumption and Social and Economic Development

The vast majority of the world's population live in poverty, in developing countries that are characterised by low levels of social and economic development, as well as inadequate infrastructure and institutions for the provision of energy services. During this century, the most important way in which countries have increased energy availability for their economies has been to invest in electricity supply. Thus, while commercial energy consumption is not equivalent to the availability of electricity services, in the absence of adequate data it may serve as an approximate measure of the latter. Figure 2.2 shows the relationship between per capita energy consumption (commercial and traditional energy) and the Human Development Index (HDI) for 100 developed and developing countries. The graph suggests that for countries with low levels of energy services, even small inputs of energy are associated with
significant welfare improvements. At higher energy consumption levels, further increases do not seem to impact greatly on human development.

This is a working paper prepared for the World Commission on Dams as part of its information gathering activities. The views, conclusions, and recommendations in the working paper are not to be taken to represent the views of the Commission.

Figure 2.2 Relationship Between per Capita Energy Consumption and HDI



Note: Data for 100 developed and developing countries.

(SOURCE: Suarez, 1995.)

The decreasing marginal benefits of energy supply on human development parallels GDP-energy de-coupling that has taken place in various countries during the 20th century. Historical trends of the "energy intensity"– or the ratio of energy consumption to GDP – of several developed economies are remarkably similar. They show rising energy intensity during early industrialisation, followed by a decline during periods of further industrialisation, this being associated with improved energy conversion efficiency, improved processes and, to a lesser extent, a general shift from manufacturing to service sectors. While this pattern of de-coupling between energy and GDP growth is most pronounced in the examples of the USA, Germany, UK, France and Japan, even a developing country, like China, and countries in transition like Poland, follow these trends, both having recently passed a peak of high energy intensity. Also, since many developing countries are entering periods of industrialisation at a stage when there are already significant opportunities for energy-efficiency, it is conceivable that they could "leap-frog" sooner than developed countries to locations on the map with low energy intensity.

Apart from their direct economic impacts, improved efficiency in energy production and use generate collateral benefits such as reduced pollution, which reduces health costs, improves productivity and reduces damage to productive assets.

2.2.2 Share of Electricity in Total Energy Consumption

The increase in fuel consumption as well the relative contribution of electricity as an energy source since the early 1970s is depicted in Figure 2.3 and Table 2.2. The evolution of final consumption of fuels since 1971 is shown in Figure 2.3. Electricity consumption has increased from 9.4 to 14.3% of total energy consumption, during the period 1973–1996 (Table 2.2).

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Energy Policy 30 (2002) 125–129

ENERGY POLICY

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Electricity consumption and economic growth in India

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Received 2 September 2000

Abstract

This paper tries to examine the Granger causality between electricity consumption per capita and Gross Domestic Product (GDP) per capita for India using annual data covering the period 1950–51 to 1996–97. Phillips–Perron tests reveal that both the series, after logarithmic transformation, are non-stationary and individually integrated of order one. This study finds the absence of long-run equilibrium relationship among the variables but there exists unidirectional Granger causality running from economic growth to electricity consumption without any feedback effect. So, electricity conservation policies can be initiated without deteriorating economic side effects. © 2002 Elsevier Science Ltd. All rights reserved.

Keywords: Causality; Electricity; GDP; India; Cointegration and vector autoregression

1. Introduction

Energy is the basic building block of economic development. Electricity is the most flexible form of energy that constitutes one of the vital infra-structural inputs in socio-economic development.

Causal relationship between energy consumption and economic growth has been the prime focus of economists and policy analysts since 1970's (Kraft and Kraft, 1978; Beenstock and Willcocks, 1981; Samouilidis and Mitropopulous, 1984; Yu and Choi, 1985; Erol and Yu, 1987; Cheng and Lai, 1997; Yang, 2000, Stern, 2000, Adjaye, 2000).

The purpose of this paper is to investigate empirically the existence and direction of causal relationship between electricity consumption and economic growth in India. Such knowledge can play a crucial role from the policy formulation point of view. If, for example, there exists unidirectional Granger causality running from income to electricity consumption, it may be implied that electricity conservation policies may be implemented without deteriorating economic growth. On the other hand, if unidirectional causality runs from electricity consumption to income, reducing electricity consumption could lead to a fall in income.

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The paper is organized in the following manner: a brief and intuitive account of econometric methodology and description of the data is provided in Section 2 before discussing the empirical results in Section 3. Conclusions of the study are produced in Section 4.

2. Econometric methodology and data description

Engle and Granger (1987) showed that if the two series X and Y (say) are individually $I(1)$ (i.e. integrated of order one) and cointegrated then there would be a causal relationship at least in one direction. The presence of cointegration among the variables rules out the possibility of "spurious" correlation. However, although cointegration indicates the presence or absence of Granger causality, it does not indicate in which direction causality runs between the variables. This direction of Granger's causality can be detected through the Vector Error Correction model of long-run cointegrating vectors. Furthermore, Granger's Representation Theorem demonstrates how to model a cointegrated $I(1)$ series in a vector autoregression (VAR) format. VAR can be constructed either in terms of the level of the data or in terms of their first differences, i.e. $I(0)$ variables, with the addition of an error correction term to capture the short-run dynamics.

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PII: S0301-4215(01)00078-7

If the series are $I(1)$ but not cointegrated, causality test may give misleading results unless the data are transformed to induce stationarity.

Following Oxley and Greasley (1998), a three-stage procedure is used to test the direction of causality. The first step tests for the order of integration of the natural logarithm of the variables using Augmented Dickey-Fuller (ADF) and/or nonparametric $Z(t_\alpha)$ statistics (Phillips and Perron, 1988). Conditional on the outcome of the tests, the second stage involves in investigating bivariate cointegration using VAR approach of Johansen (1988, 1991) and Johansen and Juselius (1990).

The third stage (or second if bivariate cointegration is rejected), involves constructing standard Granger-type causality tests, augmented where appropriate with a lagged error correction term.

The three-stage procedure for testing causality leads to three alternative approaches. If the series X and Y are individually $I(1)$ and cointegrated then Granger causality tests may use $I(1)$ data because of the super-consistency properties of estimation.

$$X_t = \alpha + \sum_{i=1}^{m} \beta_i X_{t-i} + \sum_{j=1}^{n} \gamma_j Y_{t-j} + u_t, \quad (1)$$

$$Y_t = a + \sum_{i=1}^{q} b_i Y_{t-i} + \sum_{j=1}^{r} c_j X_{t-j} + v_t, \quad (2)$$

where u_t and v_t are zero-mean, serially uncorrelated, random disturbances.

Secondly, Granger causality tests with cointegrated variables may utilize the $I(0)$ data with an error correction term i.e.

$$\Delta X_t = \alpha + \sum_{i=1}^{m} \beta_i \Delta X_{t-i} + \sum_{j=1}^{n} \gamma_j \Delta Y_{t-j} + \delta ECM_{t-1} + u_t \quad (3)$$

$$\Delta Y_t = a + \sum_{i=1}^{q} b_i \Delta Y_{t-i} + \sum_{j=1}^{r} c_j \Delta X_{t-j} + dECM_{t-1} + v_t \quad (4)$$

Thirdly, if the data are $I(1)$ but not cointegrated, valid Granger type tests require transformation to make them $I(0)$. So, in this case the equations become

$$\Delta X_t = \alpha + \sum_{i=1}^{m} \beta_i \Delta X_{t-i} + \sum_{j=1}^{n} \gamma_j \Delta Y_{t-j} + u_t, \quad (5)$$

$$\Delta Y_t = a + \sum_{i=1}^{q} b_i \Delta Y_{t-i} + \sum_{j=1}^{r} c_j \Delta X_{t-j} + v_t. \quad (6)$$

The optimum lag length m, n, q and r are determined on the basis of Akaike's (AIC) and/or Schwarz Bayesian (SBC) and/or log-likelihood ratio test (LR) Criterion.

Now, for Eqs. (1) and (2), Y Granger causes (GC) X if,

H_0: $\gamma_1 = \gamma_2 = \ldots = \gamma_n = 0$ is rejected
against
H_A: = at least one $\gamma_j \neq 0$, $j = 1 \ldots n$
and X GC Y if, H_0: $c_1 = c_2 = \ldots = c_n = 0$ is rejected
against
H_A: = at least one $c_j \neq 0$, $j = 1 \ldots r$.
For Eqs. (3) and (4), ΔY GC ΔX if,
H_0: $\gamma_1 = \gamma_2 = \ldots = \gamma_n = 0$ is rejected
against
H_A: = at least one $\gamma_j \neq 0$, $j = 1 \ldots n$, or $\delta \neq 0$
and ΔX GC ΔY if, H_0: $c_1 = c_2 = \ldots = c_n = 0$ is rejected
against
H_A: = at least one $c_j \neq 0$, $j = 1 \ldots r$, or $d \neq 0$
For Eqs. (5) and (6), ΔY GC ΔX if, H_0: $\gamma_1 = \gamma_2 = \ldots = \gamma_n = 0$ is rejected
against
H_A: = at least one $\gamma_j \neq 0$, $j = 1 \ldots n$,
and ΔX GC ΔY if, H_0: $c_1 = c_2 = \ldots = c_n = 0$ is rejected
against
H_A: = at least one $c_j \neq 0$, $j = 1 \ldots r$,

The tests are conducted on the annual data for India covering the period 1950–51 to 1996–97. Data on Gross Domestic Product (GDP) in Rupees at 1980–81 price, which is a proxy to economic growth, has been collected from "National Accounts Statistics of India" published by Economic and Political Weekly Foundation, India. Electricity consumption (in KWh) has been taken from "Public Electricity Supply, All India Statistics" published by Central Electricity Authority, India. A graphical representation of the per capita GDP and per capita electricity consumption, after dividing both the series by respective year's populations (available in National Accounts Statistics of India) is given in Fig. 1. ***Lgdp*** and ***Lel*** represent per capita GDP and per capita electricity consumption respectively after logarithmic transformation. The computer packages used for statistical analysis are Shazam (Version 8) and Microfit (Version 4).

3. Empirical results

In the first stage the order of integration of the data is investigated. Table 1 presents the results of unit root tests on the natural logarithms of the levels and the first differences of the two time series viz. per capita GDP and per capita electricity consumption. On the basis of the Phillips–Perron statistics, the null hypothesis of a unit root cannot be rejected. Stationarity is obtained by running the similar test on the first difference of the variables. This indicates that both the series are $I(1)$ in nature.

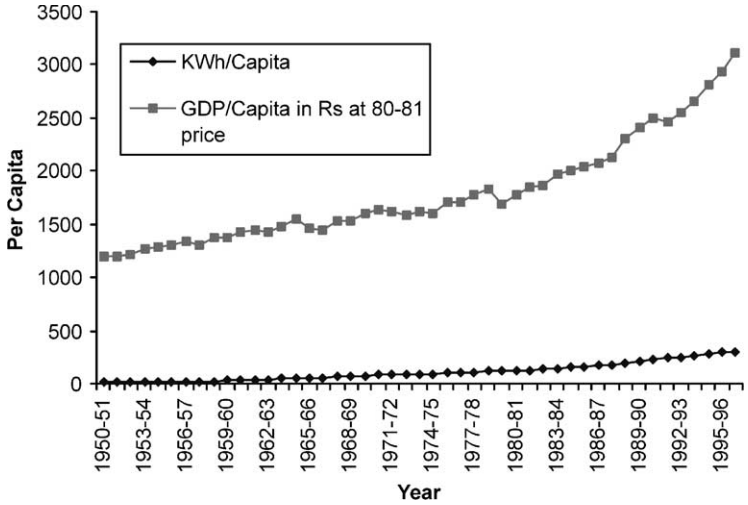

Fig. 1. Per capita GDP and per capita electricity consumption.

Table 1
Phillips–Perron unit root test

Variables	Constant, no trend	Constant, trend
Levels		
Lgdp	2.0379	−0.1288
Lel	−1.0304	−1.383
First difference		
Δ*Lgdp*	−7.7306[a]	−8.3237[a]
Δ*Lel*	−4.3299[a]	−5.3563[a]

[a] Represents rejection of null hypothesis at 10% level of significance.
Note: 90 per cent critical values for PP statistic (without trend) = −2.57. 90 per cent critical values for PP statistic (with trend) = −3.13.

In the second stage, Johansen maximum likelihood procedure is used to detect cointegration. This provides a unified framework for estimation and testing of cointegrating relations in the context of a VAR error correction model. The cointegration rank, r, of the time series was tested using two test statistics. Denoting the number of cointegrating vectors by r_0, the maximum eigenvalue ($\lambda_{\max}$) test is calculated under the null hypothesis that $r_o = r$, against the alternative of $r_0 > r$. The trace test is calculated under the null hypothesis that $r_0 \leqslant r$, against $r_0 > r$.

The results of the Johansen maximum likelihood cointegration tests are presented in Table 2. Starting with the null hypothesis of no cointegration, among the variables i.e. $r = 0$, the maximal eigenvalue statistic is 10.3785, which is below the 90 per cent critical value of 16.2800. Hence the null hypothesis of $r = 0$ cannot be rejected at 10 per cent level of significance. Turning to the trace test as shown in Table 2, the null hypothesis of no cointegration is not rejected at 10 per cent level of significance. Hence, both eigenvalue ($\lambda_{\max}$) and trace test indicate that there is no cointegration relationship between ***Lgdp*** and ***Lel***.

Consequently the bivariate system **Δ*Lgdp*** and **Δ*Lel***, where '***Δ***' is the first difference operator and hence define the growth of the respective variables, can be modeled as an unrestricted VAR.

On the basis of Schwarz Bayesian (SBC) and adjusted log-likelihood ratio (LR) test criteria, the optimal lag order of the VAR is chosen as 1. The absence of residual serial correlation of the individual equations has also confirmed the correct order of VAR selection.

Finally, Granger causality Test to the bivariate VAR has been examined. As shown in Table 3, the LR ratio

Table 2
Johansen–Juselius likelihood cointegration tests[a]

Null	Alternative	Statistic	90% critical value
Maximal eigenvalue test			
$r = 0$	$r = 1$	10.3785	16.2800
$r \leqslant 1$	$r = 2$	0.0094219	9.7500
Trace Test			
$r = 0$	$r \geqslant 1$	10.3879	21.2300
$r \leqslant 1$	$r = 2$	0.0094219	9.7500

[a] r is the number of cointegrating relations.

Table 3
Granger's causality tests

Null hypothesis	Chi-Sq (χ^2)	Dof[a]	P[b]-value
Non-causality $\Delta Lgdp \Rightarrow \Delta Lel$	4.6360	1	0.031
Non-causality $\Delta Lel \Rightarrow \Delta Lgdp$	0.0097	1	0.921

[a] Degrees of freedom.
[b] Acceptance Probability.

statistic for the test of non-causality of the growth of electricity consumption per capita in the GDP growth per capita which is asymptotically distributed as a chi-square variate with one degree of freedom is clearly not statistically significant. While testing the non-causality of GDP growth per capita in electricity consumption growth per capita equation the observed LR statistic (follows chi-square distribution with one degree of freedom) 4.6360 is found to be statistically significant. This indicates the existence of causality running from GDP growth to electricity consumption with the absence of any feedback effect.

4. Conclusion

India is a populous country accounting nearly one-sixth of the world's population. The Indian economy has grown by about 4.5% per annum on a long-term basis in the second half of the twentieth century whereas the installed power generation capacity and generation has increased at the rate of 9% and 10% per annum compounded, respectively. The demand for electricity has been growing at a compound annual rate of growth (CARG) of nearly 8% (Das et al., 1999).

This paper has investigated the existence and direction of Granger causality between electricity consumption and economic growth in India using the annual data covering the period 1950–51 to 1996–97. Empirical results have established the existence of Granger causality running from economic growth to electricity consumption without any feedback effect. Thus, a growth in income is responsible for a high level of electricity consumption. This result can be interpreted as follows.

With the advancement of Indian economy, there has been inter-fuel substitution from conventional fuel like coal, firewood and oil to electricity in various sectors. Households, because of their higher disposable income, have become more and more dependent on the electric gadgets for recreation and comfort. Economic growth causes expansion in the industrial and commercial sectors where electricity has been used as basic energy input because of its clean and efficient nature. Electricity consumption in agricultural and transport sector has also accelerated to keep pace with country's economic growth. In the agricultural sector, pumps have been energized electrically for irrigation purpose since independence. As on 31st March 1997, the total number of pumpsets/tubewells energized were 11565342 (Public Electricity Supply, All India Statistics, 1996–97). Electricity consumption in transport sector (railway in particular) has been increased at an annual growth rate of 15% between the period 1970–1995. Under such circumstances, one could reasonably expect that economic growth enhances electricity consumption in India.

Indian electricity sector has been suffering from chronic supply shortage, high T&D losses of about 25–20 per cent against the world's average of 6–9 per cent mainly because of power theft, high auxiliary consumption and environmental problems associated with the coal based power plants. Due to irrational tariff structure, most of the State Electricity Boards (SEBs) in India have been suffering from poor operational and financial performances. Lower electricity tariffs in the agricultural and domestic sector, which have been cross-subsidized by industrial sector, encourage the consumers for wasteful use of electricity.

According to the projection made by Central Electricity Authority, India need another 100,000 MW install capacity in the next 10–12 years to bridge its future demand–supply gap. Government of India (GOI) has already started electricity sector reform aimed at corporatization of SEBs and rationalization of the tariff structure to make them independent profit centers. GOI is also planing to initiate a major energy conservation and efficiency improvement program as a part of the ongoing reform process because of high energy saving potentials in India. While energy conservation aims at reducing the need for energy without reducing the end use benefit, it provides a range of personal as well as social rewards also. First, conservation is cheaper than production. For example, 1 MW of power generation costs as much as 3–4 crores whereas same power can be saved with less investment. Second, electricity conservation avoids the environmental costs associated with the additional power generation.

In this situation, the existence of unidirectional causality running from economic growth to electricity consumption in India has serious policy implications for decision-makers as electricity conservation policies

through rationalizing the tariff structure, efficiency improvement and demand side management, which aim at curtailment of wastage of electricity and there by reduce the electricity consumption without affecting the end-use benefits, can be initiated with no damaging impact on India's economic growth.

Acknowledgements

I am grateful to my wife Kakali for her help and encouragement.

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ELECTRICITY PRICES IN INDIA[1]

Pierre Audinet, *Desk Officer for South Asia and Korea, Office of Non-Member Countries*

Introduction

India's electricity-supply industry is mainly owned and operated by the public sector. It is currently running a growing risk of bankruptcy. This has created a serious impediment to investments in the sector at a time when India desperately needs them. This is reflected in the sharp decrease of the ratio of electricity consumption growth to GDP growth in the 1990s. In other words, in the past decade, electricity consumption growth did not follow economic growth. For 1991-1999, the elasticity of electricity consumption with regard to GDP was 0.97 when it was 2.1 for Korea and 0.99 for the OECD on an average[2]. High structural needs of the Indian economy would justify that such a figure exceeds 1.0, unless drastic improvements in energy efficiency took place. Actually, the low 0.97 figure is a reflection of an increasing gap between supply and demand, the continuously deteriorating quality of power[3], and a low level of access to electricity. It is also the result of large investments made by the manufacturing sector in stand-by and stand-alone facilities to compensate these deficiencies. Unless strong measures are taken immediately to correct this trend, India's overall economic development will be slowed.

The central issue now is how to enable power utilities to earn a return on investment. Price levels are too low for the system to be financially viable. In the Indian states, vested political interests impede utilities from collecting revenue. They maintain a price structure with large and unjustifiable subsidies. Politicians often interfere in the management of power utilities, hindering their efforts to curb power theft. As a result, transmission and distribution losses in India have increased, further eroding the financial situation of the state electricity utilities. These are not new trends, but the situation has reached a critical stage, where the government can no longer cover the losses of the state power utilities. For decades, the costs incurred for the development and operation of the electrical system increased faster than general economic growth, outstripping public finances' ability to make up for uncollected rates. The central government has long given priority to developing access to electricity. At the state level this meant low prices for domestic and agriculture consumers and relatively higher prices for electricity supplied to the industry and commercial sectors. Even this system did not compensate for the subsidy burden. The government was obliged to compensate the difference. Growth of the electricity sector has outstripped the growth of the public money available to bear the cost of the increasing subsidies; the mechanism is not sustainable. Nonetheless, consumers who are used to low prices, and populist politicians resist change.

To face increasing investment needs, the central government began in 1991 to focus on attracting private investment. The aim was to sustain power-sector development while keeping public expenditure under control. Competition was gradually introduced in bidding for generation projects. Since the mid-1990s, in response to the growing financial difficulties of state electricity boards (SEBs), the World Bank recommended introducing private capital into the power distribution sector and a new regulatory framework, which would allow independent tariff-setting to correct large price distortions. The central government established the legal framework for this new arrangement in 1998. More recently, it has focussed on distribution, trying to increase revenue collection and additional capital.

Unfortunately, the results of this decade of reform have fallen well below expectations and the central government now seems short of solutions. It is probably too early to judge the final outcome of the change, from a command-and-control public-dominated model to a more market-determined sector. However, the present indicators point to the need for

1 This article is based on the book *Electricity in India: Providing Power for the Millions*, which was published by the IEA in April 2002. Most of the electricity in India is still provided mainly by the electricity boards of the several federal states and has deteriorated sharply. This impedes the country's economic growth. India needs now to meet the growing demand for electricity of its large population. Vast amounts of domestic and foreign investment will be required to reach this goal. This book chronicles and analyses India's progress toward liberalisation since the early 1990s. It offers constructive advice on how to overcome the immense challenges facing the Indian electricity sector today.

2 For 1971-1990, the figures were respectively 1.7, 1.6 and 1.1 (Source: IEA).

3 With high voltage fluctuations and recurring black-outs.

urgent action. In 1995-1996, nine of the 19 SEBs incurred losses. In 2000-2001, all of them were in the red. SEBs are increasingly unable to pay for the electricity they purchase from the central public-sector power companies, or from independent power producers (IPPs). The official – and probably under-estimated – figure for transmission and distribution (T&D) losses is higher than ever, reaching 25% in 1997-98. In such conditions, the much-expected private investment has been well below expectations, and even public investments were relatively lower in recent years than before. The difficulties experienced by several private investors have discouraged potential additional investors. Unless radical measures are taken in the very short term, there is a real risk of stagnation in investment in the whole system. The demand-supply gap will continue to grow. With negligible new private investment in generation or distribution, and the central and state governments' shrinking ability to develop and maintain the power system, an increasing number of consumers will be driven to invest in stand-by or stand-alone generation sets at the expense of the public interest, challenging the very roots of social and regional equity.

Under the Constitution, electricity is on the "concurrent list", which means that the states, rather than the central government, are primarily responsible for setting electricity tariffs. The states have the largest share of generation and transmission assets and almost all distribution in their control. The states have a key role to play in effecting institutional and result-oriented changes. However, the IEA believes the role of the central government is vital in guiding the developments to come and especially in providing the necessary legal and financial incentives for the states to implement reforms.

In the following section, we bring forward some broad policy recommendations to improve electricity price formation in India. In the two remaining sections, we focus successively on two pricing issues related respectively, to the large price subsidies, and to the nexus between electricity prices and access to electricity.

Retail pricing policy and demand

Issues

Most of the problems of the Indian power sector arise from the present retail pricing system and from the fact that too little of it is actually paid for. Out of total electricity generated, only 55% is billed and 41% is regularly paid for (GOI, 2001). Electricity is either stolen, not billed, or electricity bills are not paid. All this amounts to a mass of implicit subsidy. The financial burden thus created undermines the economic efficiency and viability of the electricity supply chain and is not in the long-term interests of consumers.

Retail tariffs in India (as well as bulk tariffs) are based on a cost-plus mechanism established at the time of India's independence in 1948. Electricity prices are subsidised for domestic consumers and for farmers.

Current retail prices of electricity represent less than 75% of real average costs. There is also a large amount of cross-subsidisation between consumer categories. The agriculture and household sectors are cross-subsidised by above-cost tariffs for commercial and industrial customers and railways[4]. The situation worsened in the 1990s. Official data demonstrate that subsidies to households trebled to 80.8 billion rupees over the period 1992-1993 to 1999-2000. Subsidies to agriculture more than tripled to 227 billion rupees over the same period. The government sought to justify these subsidies on social grounds but it clearly failed to achieve its social goal, as higher-income groups in fact appropriate most of the benefits since the subsidy is applied to the price of electricity within a given consumer-category, indifferently to the individual level of income.

Policies to achieve market pricing have been introduced in India. Central and state electricity regulatory commissions are slowly being established. They will issue tariff orders, and should eventually implement them. Policies to implement a minimum price have been pursued since 1996. The goal is a minimum price of 50 paise/kWh (1.1 US cents/kWh) for agriculture. But, delays in implementing such reforms have prevented even this simple goal from being met. Inflation (8% in 2000) has outpaced the growth in price per kilowatt hour. Policies in place also call for all end-use sectors ultimately to be charged at least 50% of the average cost of supply. This target was intended to be met in three years, but it has not yet been achieved in any of the states.

The poor cost-recovery rate, the very low price and the widespread non-payment of electricity are all deterrents to private investors. Investors cannot be assured that their applications for tariff increases to recover costs will be met, even by theoretically independent regulatory commissions.

4 In theory, cost-reflective tariff structures do not differentiate between final uses of electricity. The lowest tariffs apply to customers with the highest consumption and load factors (industrial customers). Households, on the contrary, pay the highest rate due to their low load factor, limited consumption and the relatively higher cost of distribution.

The side effects of this way of subsidising energy consumption are significant. Overpricing of industrial electricity hampers competitiveness. In other sectors, underpricing of electricity is a direct incentive to waste power. Underpricing of electricity for agricultural use puts a heavy financial burden on the electricity sector and incidentally threatens water resources in the long-term. Low cost recovery translates into degradation of service, which in turn requires costly investments in stand-by capacity in the industrial and commercial sectors and by large domestic consumers. Confronted by high prices and unreliable supply from the network, big industrial consumers increasingly turn to "captive-power", which now represents more than one-third of their consumption. Every industrial consumer lost by the SEBs further worsens their financial situation since it reduces their sales base to low-paying customers. Subsidies artificially sustain demand from the consumers already connected to the grid, but a large unmet demand exists because of grid deficiencies and the inability of insolvent utilities to invest in additional connections.

Recommendations

- State governments should promote and foster payment for electricity by all customers.
- Legal action must be taken at the state level to prevent theft so that electricity suppliers have increased assurance that all customers will pay.
- Tariff should be designed to recover costs on the basis of the electricity which is sold and paid for only, separating the cost of stolen electricity from the tariff structure. Otherwise, paying customers end up being burdened with the costs of non-paying customers. To avoid such a difficulty, the unit price should perhaps be capped temporarily.
- Subsidy reform will undoubtedly result in tariff increases. To gain acceptance from consumers, the increases should be accompanied by significant improvements in the reliability, quality and accessibility of electricity supply. Restoring the investment capability of SEBs – or their unbundled sub-divisions – should be a priority. An active communications programme to explain the rationale behind subsidy reform and market pricing must accompany the reform.
- Cost-based electricity pricing needs to be implemented for all users. This requires an accurate data collection system and information on costs. If policy-makers find it appropriate to maintain partial subsidies for a particular category of consumers, the mechanism should be transparent and carefully monitored. The subsidy should also be allocated directly from the state budget to avoid burdening the utilities. It should expire within a set time frame. Access to electricity for low-income households should be carried out through direct support, or by mechanisms such as lifeline rates[5].
- Demand-side management and load management should be more actively pursued at the state levels for all sectors, particularly industry and agriculture, to reduce peak-supply shortages and increase the cost-efficiency of the system. For such measures to be successful, metering and pricing policies based on daily demand profiles should be implemented.

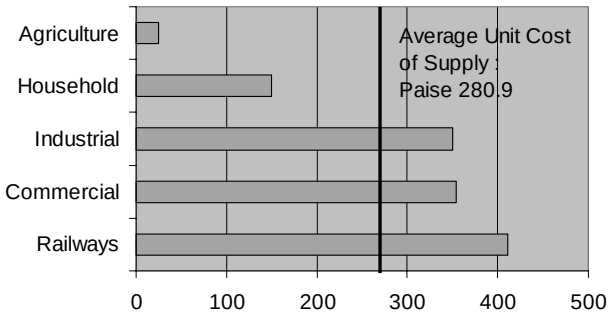
Electricity prices and subsidies

More than any other factor, the way electricity prices are determined has inhibited India's power market development. Underpricing and political interference in price determination have worsened the financial situation of the main electricity producers, wholesale buyers and suppliers: the SEBs. This increases the risk for private players who wish to enter the electricity market.

The SEBs' end-use electricity tariffs vary widely according to customer category. The major categories are households, agriculture, commercial activities, industry and railways. There are large cross-subsidies between customer categories in India: tariffs for households and agriculture are generally well below actual supply costs, while tariffs to other customer categories are usually above the utilities' reported average cost of supply. In 1999-2000, the average price of electricity sold amounted to 208 paise/kWh – 26% below the average cost of supply (see Figure 1). According to official data (GOI, 2001a), the total under-recovery of costs – the difference between total costs and total revenues – amounted to 272 billion rupees in 1999-2000, an increase of 190% since 1992-93. Most of this subsidy is reported to be for the agricultural sector. Cost recovery rates vary markedly across the country. Rates are lowest in Jammu and Kashmir, Assam, and Bihar, while the highest rates (over 90% of cost recovery) are in Himachal Pradesh, Maharashtra and Tamil Nadu.

5 This policy recommendation applies to schemes such as Kutir Jyothi, facilitating access to electricity to low income groups.

Figure 1. Average Tariffs, 1999-2000, paise/kWh



Source: GOI, 2001a.

Figure 1 clearly demonstrates that subsidies are largest in the farm and household sectors, which are cross-subsidised by above-cost tariffs for commercial and industrial customers and railways. A cost-reflective tariff structure would normally result in the lowest tariffs being charged to industrial customers, which have the highest consumption and load factor. The highest tariffs would be paid by household customers. Official data show that the nominal value of total subsidies to household customers quadrupled to 80.8 billion rupees from 1992-1993 to 1999-2000. Subsidies to agriculture more than tripled to 227 billion rupees over the same period.

The problem of underpricing worsened progressively through the early 1990s, to the degree that average revenues covered less than 76% of average costs by 1995-96. The recovery rate improved slightly up to 1997-98, but dropped sharply in the next two years to under 74%. This has mainly been due to a decline in average tariffs to agriculture, to under 25 paise/kWh. This has happened in spite of the introduction in Haryana, Himachal Pradesh, Orissa, Uttar Pradesh and Meghalaya of a minimum rate of 50 paise/kWh, as called for in the 1996 Common Minimum National Action Plan for Power. That plan also called for all end-use sectors ultimately to be charged no less than 50% of the average cost of supply), and within three years for agriculture. In no state has this goal been achieved.

Underpricing stimulates over-consumption by the beneficiary of the subsidies. In India, this is reflected in the excessive amount of electricity consumed by agriculture. Given the size of the population engaged in agriculture and its electoral importance, this largesse by policy-makers is difficult to eliminate. Vested interests hamper power-market development.

A review of historical data shows that consumption of electricity by agriculture multiplied by 19 from 1971 to 1998, whereas overall consumption multiplied only by seven. As of 1998, the sectoral structure of Indian electricity sales has differed dramatically from that of other Asian countries. In Asia, the domestic and commercial sectors generally account for almost half of electricity consumption and agriculture represents only 2%[6]. Industry accounts for 43% of overall consumption. The Indian figure is 45%, but more than one-third is auto-generated.

The amounts disbursed in subsidies are partly covered by cross-subsidies, which in turn burden less-favoured consumers, like industry. In 1999-2000, the prices paid by domestic customers, 149 paise/kWh (3.3 U.S. cents/kWh[7]), and by customers registered as being from the agriculture sector, 25 paise/kWh (0.6 U.S. cents/kWh), were far below the overall average price (208 paise/kWh). This occurred at the expense of commercial consumers (354 paise/kWh), industry (350 paise/kWh, 7.8 U.S. cents/kWh) and railway hauling (411 paise/kWh).

The distortions go further. Since the average price per kilowatt-hour is calculated dividing the revenue collected by the quantity sold to a given category of consumer, official statistics probably underestimate the average price paid by agriculture, maybe by half. Indeed, by hiding non-metered or/and non-billed consumption from other sectors into the electricity sold to the farm sector[8], the average price is artificially deflated, and the actual amount of subsidies to the farm sector could be over-estimated. This is likely to blur the official appraisal of the amount of subsidies and their actual impact on consumption.

The large cross-subsidies from industrial, commercial, and railway hauling to the domestic and agriculture sectors tend to atrophy the paid consumption of the industrial and commercial sectors. Industry is subject to planned load-shedding[9], power cuts, voltage collapse and frequency variations, i.e. the high price paid by these customers is not compensated by good-quality supply. On the contrary, the poor quality of electricity service contributed to substantial industrial output losses.

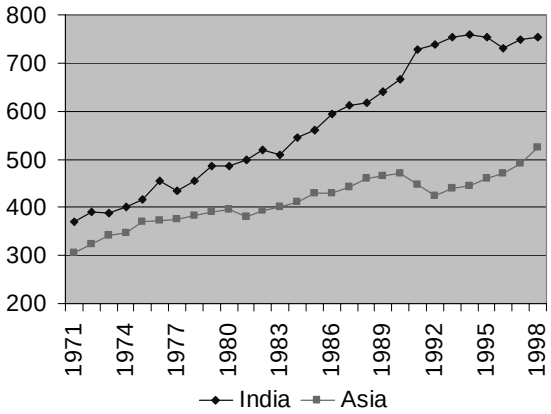
6 Excluding China, Korea and Japan.

7 This is at least ten times lower than the OECD average for the same category of customers.

8 For instance, in Uttar Pradesh, sales to agriculture for 1999-2000 were restated by the SEB as 5 122 GWh, versus 9 982 GWh resulting in an average price of 94 paise/kWh compared to the reported 48 paise/kWh (see World Bank, 2000).

9 The process of deliberately disconnecting pre-selected loads from the power system in response to a loss of power input to the system, in order to maintain the nominal value of the frequency.

Figure 2. Electricity Intensity of GDP in India and Asia, kWh of final electricity consumed per thousand 1990 USD



Note: Asia includes all non-OECD Asian countries, except China and India.

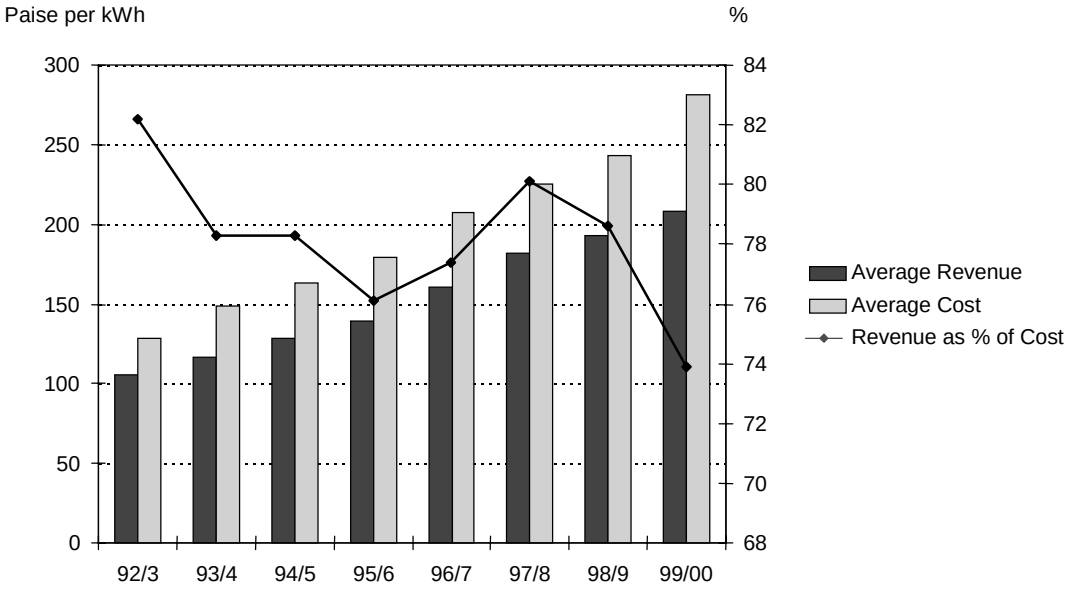
Source: IEA.

The primary effect of underpricing is to distort the overall energy market in favour of electricity. Households, farmers and others who benefit from underpriced electricity consume as much cheap electric power from the grid as possible, and account for the bulk of demand. When the cheap central supply fails, private sources have to make up for the supply gap. Customers who need electricity supply invest in resources such as batteries and diesel generators. In so doing, they cannot benefit from the economies of scale arising from the grid and use systems that are not necessary very efficient in producing electricity. The double effect of underpricing, that has resulted in growing wastage of electricity over the past decades, and the development of auto-production largely explains why India has a higher electricity intensity of its GDP than the rest of Asia (excluding China; see Figure 2).

Central government and state budgets are burdened by subsidies, which account for a large share of current expenditures, at the expense of investments in the electricity sector or other sectors such as education and health.

The subsidy problem may be larger than or different from what is suggested by the data presented here. As mentioned above, if most of these non-technical losses are allocated to sales to agriculture, the agriculture tariff issue could be less important than statistics make it appear. Conversely, the issue of non-payment could be more important than officially stated. Many customers, from agriculture but also households in urban areas, do not pay but continue to receive service. These customers effectively enjoy a 100% subsidy. This non-payment problem could far outweigh the official subsidies issue.

Figure 3. Average Electricity Supply Cost, Revenues and Cost-Recovery Rate



Source: GOI, 2001a.

Since SEBs are managed like government, it is difficult to operate the power sector on the basis of economic criteria. Metering, billing and collecting revenues have been neglected. Decision- making remains highly

centralised. Lower level employees have little decision-making authority.

An IEA study in 1999 attempted to quantify the size of electricity subsidies in India based on a price-gap analysis, the economic and (notional) financial cost of subsidies, and the potential impact subsidy removal would have on electricity consumption and related CO_2 emissions. That analysis has been updated with more recent price data (for 1999) and has been extended to cover agriculture. Table 1 summarises the results.

Table 1. Electricity Subsidies: Summary of Results

	Average price (rupees/ kWh)	Reference price (rupees/ kWh)	Rate of subsidy (%)*	Potential primary energy saving from subsidy removal (%)**
Households	1.50	3.56	57.9	48
Industry	3.50	3.42	n.a	0
Agriculture	0.25	3.56	93.0	86
Average	-	-	38.0	34

*Difference between actual price and reference price as percentage of reference price.

** TPES saved/TPES for the sectors covered by the IEA calculations.

Source: IEA calculation.

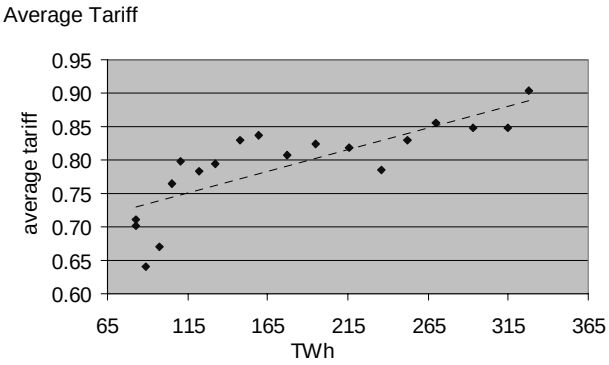
On the basis of 1999-2000 data, the rate of subsidy expressed as a proportion of the full cost-of-supply reference price amounted to 93% for agriculture and 58% for households. Electricity sales to industry are no longer subsidised. Using a –0.75 direct price elasticity of demand for the household, industry, and agriculture sectors, our analysis suggests that removing electricity subsidy would lead to significant reductions in electricity consumption, particularly in the agricultural sector. Total electricity use would be 40% lower in the absence of all subsidies. Assuming that the removal of subsidies on electricity sales reduces the demand for fuel inputs to power generation in equal proportion and that average thermal efficiency is constant at lower production levels, the use of coal and oil in thermal power plants would drop by 40%. This would lead to a 99-million-tonne reduction in power-sector CO_2 emissions, mostly due to lower coal use. The removal of specific coal subsidies would reduce emissions by an additional six million tonnes.

It is important to bear in mind the limitations of the price-gap approach, which identifies only static effects. It compares the actual situation with a hypothetical situation where there are no subsidies, keeping all other factors constant. In reality, this would never be the case. The dynamic effects of removing subsidies are likely to be significant. It could bring benefits in the form of greater price and cost transparency, gains in economic efficiency through increased competition and accountability and, consequently, accelerated technology deployment. These changes would offset, at least to some degree, the long-run static effects of subsidy removal on energy demand and related CO_2 emissions. This would be especially true for the electricity industry.

Subsidy reform, to the extent that it increases the SEBs' financial viability, would boost their capacity to invest and, therefore, increase sales to customers who currently lack access to electricity. In the long run, a reduction in subsidies could lead to an increase in electricity consumption by end-users not currently served or whose supply is severely curtailed, by blackouts, brownouts or time-limited service. Indeed, this is the implicit goal of electricity sector reforms, including subsidy reduction.

Whether this dynamic effect would be large enough to offset completely the static effect of higher prices is unclear. The size of the static effect is also unclear. As Figure 4 indicates, past experience shows a positive relationship between electricity prices and electricity consumed. The speed with which subsidy removal would lead to increased investment is also uncertain.

Figure 4. Electricity Prices and Consumption in India (1978-1996), Prices in Rs 1990 per kWh and Consumption in GWh



Source: IEA.

Any attempt to quantify the impact of electricity subsidy reform on investment in power generation would also need to take into account the economics of

auto-production. One effect of the current structure of cross-subsidies is that investment has partially shifted from the SEBs to industry itself. The 1996 Common Minimum National Action Plan for Power sought to promote auto-generation by calling on SEBs to provide access to their grid to transmit power that is surplus to a company's own needs to other end-users.

Electricity pricing and market access

Implementing more cost-reflective electricity prices when a large part of the population lacks access to electricity is a difficult task. Reforms need to benefit a large majority of the population in order to be accepted. The fact that about one-third of India's population lives below the poverty line raises the question of the initial cost of providing access to energy markets . Hence, as in many other developing countries "subsidies are likely to remain a key part of pro-poor energy policies for some time. Traditional ways to deliver subsidies often fail to help the poor. The challenge for governments is to find better ways of delivering subsidies" (ESMAP, 2000).

Healthy competition in the energy sector will eventually bring down costs and assist capital formation. In the short run, however, the consumer price will increase to reflect the costs of providing energy service without subsidies. In a country like India, there would be two negative effects of pricing energy at cost. Some consumers who are not able to pay the price may lose access to commercial energy. In the longer run, additional investments would concentrate on profitable market segments, limiting access for the part of the population unable to pay .

The benefits of society from the access to energy are easy to identify: improvements in health and hygiene through refrigeration and water heating, the immeasurable advantages of electric lighting and increase in workers' productivity, to name just a few. Another external benefit from widespread access to energy is the narrowing of social gaps But these external benefits are difficult to quantify and cannot be expected to be accounted for by energy markets. In a completely free-market system, energy is likely to be under-provided. In this respect, initial access to energy services qualifies as a social good.

Energy pricing should aim at cost recovery. But in a situation where energy is likely to be under-provided by the market, the need for some form of support to promote access to the energy service for poor households is acknowledged (ESMAP, 2000; WEC, 2000). However, the budgetary costs of subsidies are high (IEA, 1999). Financial support needs to be targeted and limited by time or income to avoid the regressive effects of subsidising energy users who are able to pay. The cost may be paid through a system of cross-subsidisation, or directly by the state, if public finances permit. The latter is preferable. The cost of a subsidy ought to be clearly identifiable; the costs of cross-subsidies might be hard to identify.

A subsidy scheme should have minimal implementation costs. In this respect, a system providing the subsidy at the supply level, such as in India has one advantage: its administrative costs will probably be lower than a system providing financial support directly to the demand-side through vouchers or income-support schemes. Direct support for demand, with the subsidy going to the consumer to cover the costs of his connection, and/or consumption, would be more efficient and cost-effective, but more expensive to administer. It would require clear rules to identify and transfer the financial support to the beneficiaries. Various options exist for excluding unwanted beneficiaries. Each of them has different budget implications.

Apart from a general under-pricing of electricity as practised in India, ad hoc subsidy schemes have been established by private investors and public utilities in developing countries at the request of local administrations or in response to populist political pressures. For example, progressive electricity tariffs (also called social tariffs) are applied to the household sector in India, and in several other developing countries: Cambodia, Vietnam, Ivory Coast, South Africa, Costa Rica, Gabon. The principle is to charge larger consumers more than smaller ones. In most cases, a system of cross-subsidies between consuming categories allows the utility to recover the cost of delivering the electricity service. Very often, however, electricity prices are too low to recover costs and an additional system of cross-subsidies is necessary. This burdens industrial or commercial consumers with subsidies for the household sector. In 1998, the Indian central government launched the Kutir Jyothi Yojna programme (literally "light for small houses"). Under this programme, SEBs must connect households under the poverty line. The government and the SEBs provide grants up to a maximum of 1 000 rupees per connection with the installation of a meter or 800 rupees per

connection without a meter. Implementation of the programme has been hindered by difficulties in identifying eligible households and by the SEBs' severe financial problems.

Such schemes need to be rationalised to reach their social target without hampering the efficiency of the whole system. The mechanism should not impose a financial burden on the utility providing the support. The threshold should not be so high as to encourage consumers to remain in the lower-consumption category, nor should the progressive tariff beyond the threshold be too steep.

The main challenge is to anticipate properly the overall cost of the subsidy mechanism. An attempt is made below to estimate the direct cost of demand-side support to electricity access.

As much as possible, access of the poor to electricity must be addressed by instruments of social policy, not by electricity pricing. If the poor cannot pay the full costs, then the difference to full costs has to be paid out of the state budget.

Box 1. The Cost of Subsidising Low-income Consumers' Access to Electricity

Let us assume that the government decides to facilitate the access of poor households to electricity by providing them with a minimum requirement, that is lifeline system, where a financial support covers the consumption of a fixed monthly quantity of power, as well as the expenditure for their connection to the grid. Let us also assume that low-income households in Indian urban areas consume roughly 50 kWh per year*. What would be the total cost of such a system?

The expenditure required to give the targeted population access to minimum electricity service has two components:

- the connection cost either through the central grid, or through local grids based on decentralised electricity production [C];
- the cost of poor households' daily consumption of power [E].

Note that the category "poor households" here refers to the part of the population that will benefit from easier access to power and does not necessarily refer to households with income below the poverty line.

The first component is a non-recurrent expenditure. The second is recurrent. The first component is significant in a developing country where the need to connect domestic customers is great and where the connection expenditure may be significant compared to the economic value of the electric supplied.

The financial transfers involved in the subsidies can take various forms. The mechanism with minimal administrative costs might be preferred. For example, money could be provided directly to the service provider, or to the final consumer, through a fixed amount deducted from the electricity bill.

The total cost of the subsidy will be [C] + [E] where:

[C] = $(C * p) / H$ and

[E] = $(S * P) / [H * (K*(1-E))]$

with:

C = average connection cost (per household)

p = number of poor urban population to be connected

H = number of persons per household

S = marginal supply cost of power for residential consumption (production + T&D)

P = estimated poor population

K = chosen lifeline consumption level

E = fixed chosen percentage of electricity billed and paid for

In the present case, the calculation of [E] is based on a simplified lifeline rate system. All consumers are assumed to be billed for their electricity at marginal cost except consumers with consumption below the chosen lifeline level. The latter are charged a fixed proportion of the actual marginal production cost of the electricity service. This provision facilitates management of the financial transfer to households as it can be handled directly by the electricity provider. At the same time, it avoids supplying a totally free service which could give the wrong signal to consumers.

The supply cost of power for household consumption is estimated at 3.4 rupees per kWh**. Moreover, we assume that one third of the existing customers and half of the additional households to be connected each year will benefit from this lifeline rate. We also assume that the price charged to this category of the population will be one rupee per kWh, and that four million households will be connected each year***.

On these assumptions, the maximum annual direct expenditure to be borne by the economy would be 44.7 billion rupees (roughly USD 1.1 billion): 11 billion rupees for connection charges for new customers and 28 billion rupees for the consumption of poor households. This is likely a maximum as the subsidy volume is calculated on the assumption that subsidised households consume their entire 50 kWh per month. Actual average consumption would probably be much lower. Special attention would have to be paid to the regular increase over time of the total direct expenditure as a result of additional consumers coming in (assuming the share of poor customers remains constant), if the support mechanism is maintained.

As an indication, the direct expenditure or cost of this support mechanism would be at least four to five times less than the current cost of subsidies for electricity consumption which amounts to 187 billion rupees, or USD 4.5 billion****.

Figures used in the calculation (1997 data)

Indian population (millions)	980
Number of households (millions)	163
Households living in electrified zone (%)	90
Number of households living in electrified zones (millions)	147
Domestic customers (millions)	70
Domestic customers in the total number of households (%)	43
Overall domestic consumption (TWh)	59
Average annual observed consumption (kWh)	846
Distribution lines 500 kV and under (km)	3 108 830
Meter cost: (purchase + installation for 1 Phase Electromagnetic kWh in rupees)	583
Connection cost per customer (rupees)	2 783
Assumptions:	
Number of persons per household	6
Length of line to be installed per new customer (m)	20

Sources:

CEA, 1998; CMIE, 2001; IEA, 1999; RSEB, 1999.

Notes:

* Poor households consume small quantities of electricity. A field survey made in a large city of south India in 1994 (Alam & al., 1998) showed that electricity represents one-fourth of the total energy consumed in the household sector (the rest is fuelwood, kerosene and LPG). In that survey, the lowest income groups consumed an average of 7 kWh per capita and per month (57 kWh per household). The figure for the richest income group was 41 kWh per capita (180 kWh per household) and the average was 15 kWh (90 kWh per household). The choice of 50 kWh as a threshold is debatable and probably on the high side. Similar progressive tariffs in other developing countries have sometimes supported lower consumption levels (e.g. up to 20 kWh per household per month).

** IEA, 1999.

*** The current rate of connection is slightly above three million.

**** As estimated in IEA, 1999. This is a conservative figure as it only accounts for subsidy transfers to households and industry.

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19. Economic development, energy, and the environment in the people's Republic of China

Fengqi Zhou

1. Economic development and the increase in energy consumption

China's internal reforms and its opening up to the outside world during the 1980s pushed the Chinese economy to new heights, resulting in an average annual GNP growth rate of 9 per cent between 1981 and 1990. Thus China has one of the most rapidly developing economies in the world today. If the GNP rate continues to increase at 6 per cent until 2000, the national economy is expected to quadruple by the end of the century.

At the beginning of 1992, the Chinese government decided to make the transition from a low-efficiency and highly centralized planned economy to a high-efficiency market economy, and to establish a socialistic market system with Chinese characteristics. Since then, the annual increase in GNP has been 13 per cent. Judging from these developments, the average annual increase in GNP in the 1990s will probably reach 8-9 per cent.

In 1990, total primary commercial energy consumption in China was 987 million tons of coal equivalent (Mtce), consisting of coal (76.2 per cent), petroleum (16.6 per cent), natural gas (2.1 per cent), and hydroelectricity (5.1 per cent). Final energy consumption by sector was: industry 68.5 per cent, residential 16.0 per cent, and others 15.5 per cent.

During the 1980s, primary commercial energy consumption grew at an annual rate of 5.1 per cent. Energy consumption per capita increased from 0.614 lee in 1980 to 0.869 lee in 1990 - an average annual growth rate of 3.5 per cent.

Total electricity generation in 1990 was 621.1 terawatt hours (TWh), of which thermal power provided 494.4 TWh (79.6 per cent). The annual growth rate of electricity generation was 7.5 per cent during the 1980s. In 1990, the total energy used for electricity generation was 212 Mtce, in which coal, fuel oil, and diesel accounted for 89, 7, and 3 per cent, respectively. Final electricity consumption by sector was: industry 78.2 per cent, residential 7.7 per cent, agriculture 6.9 per cent, and others 7.2 per cent. Electricity consumption per capita increased from 306 kilowatt hours (kWh) in 1980 to 549 kWh in 1990, with an average annual growth rate of 6.5 per cent.

Depending on the rate of growth of the economy, the Energy Research Institute has made a forecast of energy demand for the year 2000. If the coefficient of elasticity of primary energy consumption is 0.45 (it was 0.56 in the 1980s), and the annual average rate of energy conservation is 4 per cent, the aggregate of primary energy consumption will be 1,450 Mtce, including 1,500 Mt of raw coal, 165 Mt of crude oil, 25 billion m^{3} of natural gas, and electricity generation of 1,350 TWh, including 240 TWh of hydropower and 10 TWh of nuclear power.

2. The environmental challenge of energy development

The main energy-related environmental problem in China is urban air pollution caused by the burning of large amounts of coal. In 1990, coal consumption in China was 1,055 Mt. 80 per cent of which was burnt directly, which caused serious air pollution.

In 1990, total emissions of particulates were 13.24 Mt in China, 70 per cent of which were from coal combustion. The daily average concentration of total suspended particulates in China's cities is 387 m g/m^{3}, and it is higher in the northern cities than in the southern cities.

In 1990, total SO_2 emissions were 14.95 Mt in China, 90 per cent of which were from coal combustion. The daily average concentration of SO_2 in cities was 93m g/m^3. These massive emissions of SO_2 are leading to serious SO_2 pollution in urban areas. In a quarter of cities in northern China, the SO_2 concentration has exceeded level 3 of the national standard (which is 100m g/m^3). In southern China, especially in the south-western area, there is acid rain in some regions. In the worst places, the pH value of precipitation is below 4.

It is estimated that CO_2 emissions from fossil fuel combustion were 564 MtC in 1990, 85 per cent of which were from coal combustion. In addition, overconsumption of biomass energy, vegetation loss, and the failure to return large amounts of straw to the land resulted in soil erosion and a reduction in organic content. The national area of soil erosion has reached 150 million hectares, and the national average organic content in farmland is below 1.5 per cent.

Given that coal consumption is predicted to reach 1,500 Mt in 2000, air pollution will continue to get worse. The right strategy and effective measures are needed to control serious air pollution.

3. An energy efficiency strategy

Energy conservation and improvements in energy efficiency are the best means of harmonizing the development of energy and protection of the environment.

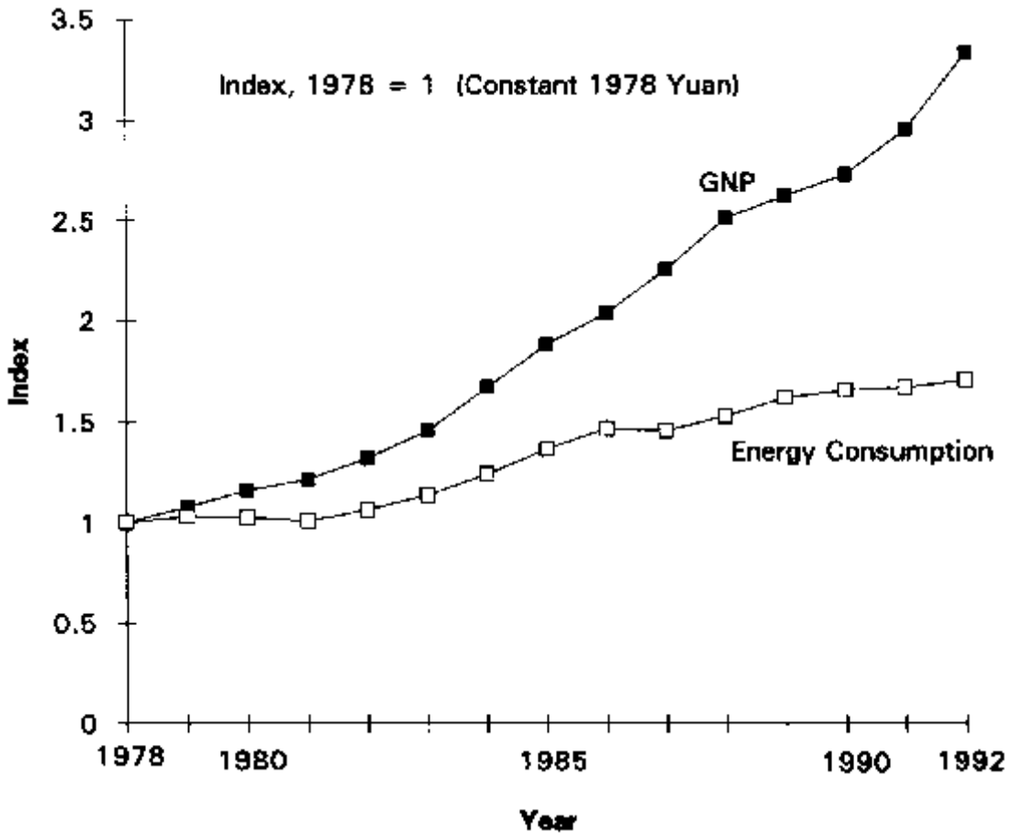
China has made considerable progress in energy conservation. From 1980 to 1990, the average annual increase in commercial energy consumption was 5.1 per cent, whereas the average annual growth rate of GNP was 9.0 per cent, giving an elasticity of energy consumption of 0.56. Energy consumption per 10,000 yuan GNP decreased from 13.36 lee in 1980 to 9.3 lee in 1990, a drop of 30 per cent. This represents an average annual energy conservation rate of 3.7 per cent, and a cumulative saving of over 280 Mtce. Nearly two-thirds of this was saved indirectly through changing macroeconomic structures; the rest was saved directly by industrial enterprises.

Goldemberg suggested in chapter 17 that energy intensity in developing countries is increasing, with the notable exception of China, whose energy intensity is clearly declining. This indicates a de-coupling of energy consumption and economic growth (see fig. 19.1).

Improvements in energy efficiency are at the core of efforts to reduce air pollution and greenhouse gas emissions. During the 19801990 period, it is estimated that, as a result of energy conservation, there was a reduction in particulate emissions of 0.5 Mt and in SO_2 emissions of 0.55 Mt every year.

China's development target calls for further reductions in commercial energy intensity of at least 35-40 per cent per unit of GDP from 1990 to 2000. This further energy saving can be achieved, but there are major obstacles to be overcome. Success will require both further substantial structural savings and an acceleration in technical reform to increase energy efficiency.

Fig. 19.1 De-coupling energy consumption and economic growth in China, 1978-1992



4. A strategy of clean coal technologies

China is one of the few countries that uses coal as its major energy source. In 1990, coal accounted for 76.2 per cent of primary energy consumption, supplying 70 per cent of fuel for electricity generation, 60 per cent of raw materials for the chemical industry, and 80 per cent of residential fuel utilization. It is estimated that, by the year 2010, coal will still account for 66.7 per cent of consumption, and even in 2050 the share of coal will be above 50 per cent. This coal-dominated energy structure is unlikely to change in the near future unless there is a breakthrough in new energy technologies.

The important role of coal is determined by the state of its reserves. Because proven reserves of coal comprise 90 per cent of the total proven reserves of primary energy in China, it would be impossible not to use it. The best strategy would therefore be to spread "clean coal technologies" (CCT), which is the general name for technologies that increase energy efficiency and reduce pollution. In the United States and Japan, CCT has played a leading role. China has also paid great attention to it in recent years and made some progress. Ten kinds of CCT have been studied and ranked according to assessments of technological and economic characteristics: coal selection, briquette coal, coal water mixture (CWM), advanced combustor, fluidized bed combustion

(FBC), integrated gasification combined cycle (IGCC), flue gas treatment, coal gasification, coal liquefication, and fuel cells.

China is a developing country and it would be impossible to halt or delay economic development. However, we should show responsibility towards the world and posterity, by making every effort to reduce the effects of energy development on the environment. We should admit that clean coal is the "future energy" and that developing clean coal technologies is an important strategy.

Comments on part 6

Hoesung Lee

The papers in part 6 all emphasize the importance and desirability of pursuing an energy-efficient development path. Professors Goldemberg and Reddy both argue for the de-linking of energy and GDP growth in developing countries through the adoption of energy-efficient technologies early in the development process. They provide examples from Brazil and India that demonstrate the possibility of moving toward energy-efficient growth, although the Brazilian example is of future plans for such growth and the Indian example is a small village development experience. They conclude that developing countries should be able to leapfrog old technologies to achieve an energy-efficient growth path.

I agree with their conclusions for energy-efficient growth strategies for developing countries. It is difficult to take issue with a growth proposal that has energy efficiency at its core, especially when energy efficiency improvements are one of the most cost-effective ways to reduce carbon dioxide emissions. But how do we achieve the goal of an energy-efficient growth path? One can observe many practical barriers standing between reality and the goal. These are what I shall comment on.

The energy/GDP ratio is lower in industrialized countries because, as the authors indicate, (a) energy efficiency in each individual sector is better than in developing countries, and (b) the economy is dominated by energy-efficient industries. This implies that the first task for the developing countries is to improve end-use energy efficiency. More specifically, they need to find out why energy-efficient technologies are not used as much in developing countries as in the industrialized countries. Developing countries may enjoy latecomers' advantages, as suggested by Professor Goldemberg, but the prospects for improving energy/GDP ratios are not bright.

In most developing countries, energy prices are subsidized to keep them considerably below costs. In these circumstances, it is likely that an energy-intensive industrial structure will be sought. As a result, the physical energy input per unit of output the energy/GDP ratio in aggregate - will be higher than otherwise.

However, this does not necessarily imply that energy expenditures per unit of output will also be higher. What matters in the investment decision is energy expenditures, not the quantity of energy use. A high energy/GDP ratio reflects an energy-inefficient outcome, but, given low energy prices, it makes good business sense to have high energy intensity. This is why the inefficient outcome is sustainable.

In order to achieve a lower ratio for energy/GDP in developing countries, energy prices should be rationalized. But this is easier said than done. Energy prices in developing countries reflect a complex mixture of economic, social, and political interdependencies. The task then is how to induce the adoption of energy-efficient technologies in a situation of low energy prices. Market competition and energy efficiency regulations play a critical role.

Experience in Korean manufacturing industries indicates that the more the industries are subject to competition, especially export competition, the higher the energy efficiency in those industries. Energy efficiency standards are also effective and complement market competition. Industries are, however, generally reluctant to see the tightening of efficiency standards.

In conclusion, in order to realize an energy-efficient growth strategy, the following conditions must be satisfied:

- no energy price subsidies
- market competition
- energy efficiency regulations.

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