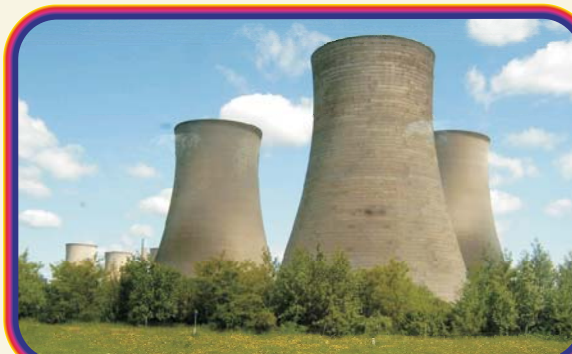
REPORT ON MINIMISATION OF WATER REQUIREMENT IN COAL BASED THERMAL POWER STATIONS

CENTRAL ELECTRICITY AUTHORITY
New Delhi – 110066

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संदेश

ओं शं नो देवीरभिष्टय ऽ आपो भवंतु पीतये । शं योरभि स्रवंतु नः ।।

इस मंत्र का भाव है कि दिव्य गुणवाले जल हमारे लिए कल्याणकारक होवें, इष्ट सुख शांति की प्राप्ति के लिए, और पीने के लिए होवें। उनके सदुपयोग से हम पर कल्याणकारक, सर्वदुःख निवारक सुख की वर्षा होवे । इससे पृथ्वी पर जल की समस्त प्राणियों के लिये उपयोगिता सिद्ध होती है। जल के यथार्थ प्रयोग से हम विविध सुखों व ऐश्वर्यों को प्राप्त होवें । अतः यह ताप विद्युत संयंत्रों सहित अन्य उद्योग-धंधों के लिए भी बहुत अनिवार्य है । पिछले कुछ वर्षों में जल की उपलब्धता वर्तमान तथा भविष्य में स्थापित होने वाले ताप विद्युत परियोजनाओं के लिए एक विकट समस्या बन गई है । जल के उपयोग की सबसे अनिवार्य प्राथमिकता पेय जल तथा सिंचाई है । वर्षा मे जहां जल की अधिक उपलब्धता होती है, वहीं ग्रीष्मकाल में जल की सीमित मात्रा अनेक समस्याएं प्रस्तुत कर देती है । यद्यपि वर्षा जल को संग्रह करने के लिए बांध/जलाशय आदि बनाये जा सकते हैं किन्तु इस काम की अपनी अलग सीमायें/समस्याएं हैं । अतः ताप विद्युत परियोजनाओं के उपयोग मे आने वाले जल की यदि हम कुछ बचत कर सकें तो यह मानवता के लिए एक पुनीत कार्य होगा व बचा हुआ जल अन्य परियोजनाओं के लिए उपलब्ध हो सकेगा ।

विद्युत अधिनियम-2003 की धारा 73 के अनुसार, केन्द्रीय विद्युत प्राधिकरण को जो कार्य सौपे गये हैं, उनके तहत अनेक प्रलेख (डाक्यूमेंट) बनाये जाने हैं।

उपरोक्त तथ्यों को ध्यान में रखते हुए केंद्रीय विद्युत प्राधिकरण में एक समिति का मई 2009 में गठन किया गया था जिसका मुख्य कार्य ताप विद्युत संयंत्रों में उपयोग में आने वाले जल की यथासंभव बचत के लिए सुझाव देना भी शामिल था । इस समिति में एन.टी.पी.सी., बी.एच.ई.एल., राजस्थान राज्य विद्युत उत्पादन निगम, महाजेनको, सी.ई.एस.सी. तथा टी.सी.ई. के सदस्य थे । समिति ने अनेक बैठकें की तथा अपनी संस्तुति "Report on minimisation of water requirement in coal based Thermal Power Stations" नामक रिपोर्ट के रूप में दी है । मैं समिति के सभी सदस्यों को साधुवाद देना चाहूंगा कि उन्होंने अपने अथक प्रयास से यह पुनीत कार्य संपन्न कर दिया है ।

मुझे यह पूर्ण विश्वास है कि उपरोक्त रिपोर्ट में दर्शाए गए जल उपयोग संबंधित मानक, ताप विद्युत परियोजनाओं के परिचालन व योजना से संबंधित सभी लोगों का मार्गदर्शन करेंगे और जल की बचत करने में सहायक सिद्ध होंगे । इसमें दिये गये विवरणों को और अधिक उपयोगी बनाने व भविष्य में जल की खपत को कम करने हेतु आप सभी के बहुमूल्य सुझाव भी आमंत्रित हैं ।

नई दिल्ली
जनवरी, 2012

(कुँवर पाल सिंह)

CONTENTS

REPORT ON MINIMISATION OF WATER REQUIREMENT IN COAL BASED THERMAL POWER STATIONS

1.0 Introduction

Water is one of the key input requirements for thermal power generation. Water is required for process cooling in the condenser, ash disposal, removal of heat generated in plant auxiliaries, and various other plant consumptive uses. For power plants located on main land, the raw water is generally drawn from fresh water source such as river, lake, canal, reservoir, barrage. Treated sewage water may also be used as source of raw water for the power plants located adjacent to the cities. For power plants located in coastal areas, water for cooling of condenser and auxiliaries is drawn from the sea or creek which provides for water requirement of the wet ash handling system also. The requirement of water for other plant consumptive uses is met from an alternative source or by installing desalination plant.

Large coal based capacity is required to be added during 12th Plan and beyond at the pace of about 15000 MW per year. Difficulties are already being faced in siting thermal power plants due to non-availability of water, particularly in coal bearing states like Orissa, Jharkhand and Chhattisgarh. This problem is expected to be aggravated in future when more sites would be required. Thus there is a need to minimise consumptive water requirement for thermal power plants.

In States like Rajasthan, the land is available in plenty but there is scarcity of water and naturally drinking and irrigation uses have got priority over industrial uses. In such areas where there is acute shortage of water, use of dry cooling system for condenser cooling can be explored. The condenser pressure achievable in dry cooling system is considerably higher than in wet cooling system and consequently dry cooling systems result in reduced power output and increased heat rate (lower efficiency) of the unit besides higher capital cost. There are considerable number of dry cooling installations including for large size units (≥ 600 MW) operating in different parts of the world. In India also, some small size combined cycle plants, captive power plants and industrial units have been provided with air cooled condensers.

In the above background, CEA, vide circular dated 27.5.2009, constituted a Committee with members drawn from NTPC, BHEL, RRVUNL, MAHAGENCO, CESC and TCE to examine suitability of dry cooling system for condenser cooling in thermal power plants so as to reduce plant consumptive water by a significant order. Later, the scope of the study was widened to include minimisation of plant consumptive water requirement.

2.0 Deliberations

The first meeting of the Committee was held on 19.6.2009 in CEA, New Delhi in which a presentation was also made by SPX- Balcke Duerr on dry cooling system. The second meeting of the committee was held in CEA, New Delhi on 25.6.2009. The focus in these meetings was on reducing plant consumptive water requirement by use of dry cooling system for condenser cooling in thermal power plants. It was agreed that techno-economic studies shall be carried out for one project site of NTPC comprising of coal based 500 MW size units and one project site of RRVUNL comprising of lignite based 125 MW size units.

In the second meeting of the Committee, a sub-group comprising with members drawn from CEA, NTPC, BHEL and TCE was constituted to firm up site input data and design data for dry cooling system and work out the details of techno economic studies for the selected project sites with requisite inputs to be taken from project utilities, BHEL and suppliers of dry cooling systems. The sub-group held its meetings on 11.9.2009, 25.9.2009 and 23.3.2010. Interactions were held with two suppliers of dry cooling system viz. M/s SPX/ Thermax and M/s GEA- EGI/ Energo, and technical data and budgetary cost data of dry cooling system required for the study were obtained from them. In the third meeting of the sub-group held in CEA, New Delhi on 23.3.2010, it was agreed that techno-economic study shall be carried out only for 500 MW size unit keeping in view similarity of expected results for 125 MW size unit, and poor response regarding receipt of input data pertaining to study for 125 MW size unit.

CEA prepared draft report of the Committee and circulated to the Committee members on 23.6.2010. The draft report was discussed in the third meeting of the committee held in CEA, New Delhi on 6.8.2010. Report of the Committee has been finalised based on the deliberations held in the meeting and inputs received subsequently.

The list of officers who participated in above deliberations is given at Annexure-1.

3.0 Plant Water Requirement

Plant consumptive water requirement is governed by a number of factors such as quality of raw water, type of condenser cooling system, quality of coal, ash utilization, type of ash disposal system, waste water management aspects etc. In the past, power stations were designed with water systems having liberal considerations for various requirements and high design margins. Ash handling system used to be designed for disposal of both fly ash and bottom ash in wet form using lean slurry with ash to water ratio of typically 1:10. The consumptive water requirement for coal based plants with cooling tower used to be about 7 m^3/h per MW without ash water recirculation and 5 m^3/h per MW with ash water recirculation.

In recent past, plants have been designed with consumptive water requirement in the range 3.5 - 4 m^3/h per MW. The typical break-up of plant consumptive water, taken as 4000 m^3/h, for a typical 2x500 MW plant with wet ash disposal without recycling of ash pond water is indicated as below:

➢	Cooling tower make up	:	3450 m^3/h
➢	Ash disposal	:	1300* m^3/h
➢	DM water make up	:	120 m^3/h
➢	Potable & service water	:	250 m^3/h
➢	Clarifier sludge etc.	:	110 m^3/h
➢	Coal dust suppression	:	70 m^3/h
	Total	:	4000 m^3/h

*To be tapped from CW system as blow down water and as such not considered in consumptive water."

It may be mentioned that more than 80% of input water is required for make up to the cooling tower. There is continued endeavour for reduction of plant consumptive water requirement, which is discussed in succeeding part of the report.

4.0 Plant Consumptive Water and Optimisation/ Minimisation Aspects

Water is used in almost all areas/ facilities of thermal power stations in one way or other. A typical list of plant systems/ applications requiring consumptive water is indicated as below:

i) Cooling water system for condenser & plant auxiliaries
ii) Ash handling system
iii) Power cycle make up
iv) Equipment cooling system
v) CPU regeneration, if applicable
vi) Air conditioning and ventilation system
vii) Coal dust suppression system
viii) Service water system
ix) Potable water system
x) Gardening
xi) Evaporation from raw water reservoir

Optimisation/ minimisation of plant consumptive water includes measures such as judicious utilization of water in different applications, adoption of reduced margins in various consumptive uses, adequate treatment for deteriorating quality of raw water, use of plant waste waters in various low grade applications and recycling of plant waste waters to maximum extent. The requirement and scheme for utilization of plant waster waters is also governed by stipulation of MOE&F and CPCB/ SPCB in this regard. In some recent projects, MOE&F has stipulated the requirement of zero effluent discharge from plant boundary which has a large bearing on plant water scheme and treatment of waste water to be adopted.

A brief description of above plant systems which have potential for further reduction in water consumption and aspect of waste water minimization is given below:

4.1 Cooling Water System

Cooling water is required for condensing of steam in a surface condenser and for secondary cooling in heat exchangers of equipment cooling system for plant auxiliaries. For a typical 500 MW coal fired unit, the amount of cooling water required for condenser and auxiliary cooling is of the order of 60,000 m^3/h with temperature rise across the condenser about 9.5^0C.

Cooling water system may be of once through type or closed cycle type using cooling tower. As per MOE&F's stipulation dated 2.1.1999, the power plants installed after 1.6.1999 and based on fresh water sources are not permitted to go for once through condenser cooling system keeping in view thermal pollution aspects of the source water body. Once through type cooling system using sea water is allowed only in coastal regions with permitted temperature of discharged hot water as 7 ^0C above the temperature of receiving water body.

In case of once through system, the additional evaporation from the surface of the water body to dissipate the imposed heat load by the power station amounts to about 1% of the circulating water flow rate. In case of closed cycle system, use of cooling tower result in evaporation of 1.5- 1.7% of CW flow for heat removal from circulating water. For a typical 500 MW unit, evaporation of water in the cooling tower amounts to about 1000 m^3/h. Drift loss amount to typically 0.05% of the CW flow.

In case of closed cycle system, make up water is added in the CW system to compensate for loss of water on account of evaporation, drift and blow down affected from the CW system to maintain a desired level of dissolved solids in the circulating water. The requirement of make up water (M) to be supplied, and blow down water (B) to be affected from the CW system are dependent on cycles of concentration (COC) of the CW system as below:

$$M = \frac{E.\,C}{(C-1)} \quad \text{and}$$

$$B = \frac{E}{(C-1)} - D$$

where, E is evaporation from cooling tower, D is drift loss to the atmosphere, and C is the cycle of concentration (COC) of the CW system.

The permissible COC which can be maintained in the CW system is dependent on quality of cooling tower make up and scheme of cooling water treatment adopted. In the past, CW systems have been designed with COC in the range 3 to 1.6 depending upon requirement of water for wet ash disposal in the form of lean slurry. Even raw water was used as make up to cooling tower with COC of the order of 1.6. Subsequently, clarified water was used as make up to the cooling tower with typical COC of about 3 requiring make up water of about 2.5% of CW flow.

In the present study, CW system is considered to be operated at COC of 5.0 with requirement of make up water typically about 2.1 % of CW flow (comprising of 1.7% evaporation loss, 0.05% drift loss and 0.35 % as blow down). The blow down water is considered to be used for disposal of bottom ash, and unutilized blow down, if any, is led to central monitoring basin (CMB) of the plant for further utilization/ treatment/ disposal outside the plant boundary. The quantum of blow down water can be further reduced by increasing the COC of CW system which can be achieved by suitably improving the chemical regime of circulating water, if feasible.

In case of dry condenser cooling system, wet cooling tower is required only for ACW flow and requirement of plant make- up water is considerably reduced. The aspect of dry cooling system for thermal power plants is covered at para 5.0 and 7.0 of this report.

4.2 Ash Handling System

Combustion of coal in a thermal power plant results in generation of ash which needs to be disposed off. The amount of ash generated depends upon the quality of coal particularly its calorific value and its ash content. For a 500 MW unit burning typical Indian coal (of 40% ash), the amount of ash generated is about 140 ton/h with distribution of fly ash and bottom ash as 80:20.

Fly ash and bottom ash generated in the plant has traditionally been disposed to ash pond in the form of wet slurry. Over a period of time, environmental concerns associated with ash generation in thermal plants have resulted in various measures to be adopted viz. reducing water requirement for wet ash disposal, dry disposal of fly ash and utilization of ash in various applications. The measures for reducing consumptive water requirement include reducing water to ash ratio for slurry disposal, recirculation of ash pond water and use of high concentration slurry disposal (HCSD) system for fly ash. In recent plants, wet disposal of ash has been adopted with slurry concentration of 30% for fly ash and 25% for bottom ash. In the plants using ash water recirculation, typically 70% of ash pond water can be recovered and reused in ash handling plant. Thus, net water to be supplied for ash disposal gets reduced to about 30% of requirement of ash handling plant. As regards HCSD system for fly ash, the process involves pumping of high solids concentration slurry with more than 60% solids by weight employing positive displacement pumps as compared to lean slurry transportation at about 25- 30% concentration.

As per MOE&F's notification dated 3.11.2009, all new coal based power stations are required to progressively achieve 100% utilization of fly ash by fourth year from date of commissioning of the project. Thus, fly ash may be disposed off in wet mode (lean slurry or HCSD mode) only during initial period of plant operation as above. Bottom ash shall, however, have to be disposed in wet/ semi-wet form since proven technology for dry evacuation of bottom ash is not available for large size plants. As such, water shall be required for transportation of bottom ash and quantum of fly ash to be disposed off in wet/ semi-wet mode in initial years of plant operation and during emergency when dry fly ash mode is out of operation.

For wet/ semi-wet disposal of ash, water is tapped from available CT blow down. During the period plant is operated without recovery of ash pond water, the increased requirement of water needs to be met from additional water to be drawn from raw water source. When ash water recirculation system of the plant becomes operational, about 70% of ash water is expected to be available for reuse in ash handling system. Under this condition, available CT blow down will suffice to meet make up water requirement of ash handling plant and no additional water will be required to be drawn from raw water source. As such, additional water will be required from raw water source only till ash water recirculation system becomes operational. However, if HCSD system is used instead of wet slurry system for disposal of fly ash, available CT blow down shall suffice to meet water requirement of HCSD system and no additional water will be required from raw water source.

In line with above, the present study considers fly ash to be disposed in dry form and bottom ash in wet slurry form under normal mode of plant operation. Wet slurry or HCSD system is considered for disposal of fly ash during initial period of plant operation till full utilization of fly ash in dry form is achieved in line with MOE&F's notification dared 3.11.2009 or during emergency condition.

4.3 Power Cycle Make- up

Power cycle make up refers to DM water added in condenser hotwell to compensate for loss of water due to boiler blow down and other losses from the system. The quantum of blow down water depends on boiler steam parameters and quality of make up DM water. In the past, the DM water make up requirement of power cycle has been amply considered even upto the order of 8% of BMCR flow. Over a period of time, this requirement has been reducing, and now a days, design power cycle make up is generally taken as 3% of BMCR flow. As per this, power cycle make up requirement for a typical 500 MW unit shall be about 50 m^3/h. In actual, plants are being managed with further reduced make up also as large size units are provided with condensate polishing units (CPU) and materials of better metallurgy are used in feed heating and boiler components. In the present study, power cycle make has been considered as 2% of BMCR flow.

4.4 Coal Dust Suppression

Water is sprayed over heaps of crushed coal, belt conveyors, transfer points and during coal unloading in order to reduce nuisance due to fugitive dust emission. Amount of water required for coal dust suppression depends upon size of coal stockyard, coal consumption rate, volatility of coal and ambient conditions. Normally, low- grade water such as CT blow down or plant waste water is used for coal dust suppression. In order to reduce plant water consumption, water available from drains of coal yard can be recovered and reused for coal dust suppression water system.

4.5 Evaporation from Raw Water Reservoir

The storage requirement of raw water reservoir for plant depends upon availability of raw water from the source. The rate of evaporation from the surface of the reservoir depends upon surface area of the reservoir and prevailing ambient conditions. In the present study, the power plant is considered to have been envisaged with a raw water reservoir of capacity for 10 days plant requirement with effective water depth taken as 8 m. The evaporation from surface of the reservoir has been estimated considering loss of 20 cm water depth in a month which is equivalent to average evaporation of about 1.2 m^3/h per acre of reservoir surface. As per above, for a typical 2x500 MW plant, the evaporation from surface of raw water reservoir amounts to about 30 m^3/h. In case surface area of the reservoir envisaged is more than that worked out as per above criterion, the quantum of reservoir evaporation shall increase accordingly.

4.6 Minimising Effluent Discharge

Waste water generated in a thermal power plant typically includes clarifier sludge, filter back wash, CT blow down, regeneration waste of DM plant & CPU, and boiler blow down etc. Normally, clarifier sludge is disposed off alongwith ash slurry and boiler blow down is led to central monitoring basin (CMB) of the plant. Water required for wet ash disposal is tapped from CT blow down, and unutilized blow down water, if any, is led to the CMB.

In the present study, clarifier sludge is considered to be treated for removal of solid waste, and recovered water is recycled to inlet of the clarifier. Filter back wash water from filters of DM plant and potable water system is also considered to be recycled to inlet of the clarifier. The boiler blow down is considered to be used in CW system to supplement the make up water as it is expected to have negligible impact on CW inlet temperature. The plant drains and side stream filter back wash are treated in effluent treatment plant (ETP), and recovered water is collected in the CMB. Requirement of water for low grade applications such as coal dust suppression and gardening is met from CMB. The balance waste water of CMB is handled in line with stipulations of MOE&F/ CPCB/ SPCB, as applicable.

The waste water in CMB has high TDS on account of regeneration waste and CT blow down water. If water is to be recovered from this waste water for recycling in the plant, its treatment would require application of reverse osmosis technology. The requirement of plant input water shall reduce by the quantum of water recovered from RO plant. The concentrated brine reject of R.O plant can be used for coal dust suppression or it can be used for wet disposal of bottom ash.

5.0 Water Minimisation by Use of Dry Cooling Systems

In a conventional wet cooling tower, hot water is cooled by direct mixing with ambient air resulting in evaporation of a part of circulating water, and make up water is required to compensate for loss of water due to evaporation, drift and blow down water. Dry cooling systems do not require any make up water as rejection of power cycle waste heat from condenser to atmosphere takes place by sensible cooling in finned tubes by ambient air and no evaporative cooling is involved.

Dry cooling systems can be broadly classified in two categories viz. direct dry cooling systems and indirect dry cooling systems. In direct dry cooling system, exhaust steam from LP turbine is directly cooled in a system of finned tubes by ambient air using mechanical draft fans or natural draft hyperbolic tower. In an indirect dry cooling system, exhaust steam from the turbine is cooled by water in a surface or jet condenser and hot water is cooled by air in finned tube bundles using mechanical draft fans or natural draft hyperbolic tower.

In case dry cooling system is adopted for the condenser, wet cooling tower is required only for ACW flow and requirement of plant make- up water is considerably reduced. Since CT make up water constitutes major part of plant consumptive water, use of dry cooling system results in reduction of plant consumptive water by about 80%. The requirement of plant consumptive water can be further reduced by adopting dry cooling mode for ACW flow also using air cooled heat exchangers.

6.0 Optimised Plant Water Requirement

As can be seen from above, various options exist for reduction of plant water consumption which need to be applied on case to case basis. In the present study, the following three cases have been considered for optimisation/ minimization of water consumption in 2x500 MW coal based thermal power plants (fresh water in case of coastal plants):

i) In-land power plants with wet cooling tower using indigenous coal;

ii) In-land power plants with dry condenser cooling system using indigenous coal;

iii) Coastal plants based on sea water cooling.

Typical water balance diagrams for the cases listed above considering fly ash disposal in dry form and bottom ash disposal in wet slurry form are indicated in Annexure- 2 to 4. The details of plant water requirement and waste water generation for the above cases is indicated in the Table- 1 below:

Table- 1, Plant water requirement (m^3/h) for a typical 2x500 MW coal based thermal power plant (m^3/h).

Sl. No.	Description	In-land plants using indigenous coal with		Coastal plants (fresh water)
		wet cooling tower	Dry condenser cooling system	
A	**Plant Input Water**			
1	Cooling Tower make up			-
	a) Evaporation	2040	138	
	b) Drift	60	6	
	c) Blow down	450	30	
	Sub- total	2550	174	
2	Bottom ash handling system make up	90*	90**	Sea water
3	DM Plant input	85	85	85
4	Service water	200	200	230
5	Potable water system input	52	52	52
6	#Reservoir evaporation	30	5	3
7	Side stream filter back wash (considered as part of CT blow down)	30	2	-
8	Clarifier sludge	90	15	10
9	Sludge water recovery	(-)83	(-)14	(-)9
10	Filter backwash water recycled	(-)5	(-)5	(-)5
11	Boiler blow down used as CT make up	(-)20	-	-
12	**Plant input water** (1+3+4+5+6+8-9-10-11)	**2899**	**512**	**366**
	Say	**3000**	**550**	**400**
B	**Plant waste water**			
1	Unused CT blow down	350	-	-
2	DM & CP plant regeneration	10	10	10
3	Treated effluent of plant drains etc.	53	26	24
4	Treated effluent from fuel oil area	5	5	5
5	Waste water utilized for coal dust suppression/ ash disposal	(-)50 (coal dust suppression)	(-)22 (ash disposal)	(-)20 (part coal dust suppression)
6	Waste water utilized for gardening	(-)5	(-)5	(-)5
7	**Waste water to be disposed from CMB** (1+2+3+4- 5-6)	**363**	**14**	**14**

* 70 m^3/h to be met from CT blow down and 20 m^3/h availalble as seal water for AHP pumps.

** to be met as 28m^3/h from CT blow down, 20 m^3/h as seal water for AHP pumps, 20m^3/h as boiler blow down and 22 m^3/h from CMB.

for reservoir surface area corresponding to 10 days plant requirement with water depth as 8 m.

Note: The above assessment of water requirement involves following salient considerations:

i) For in-land plant with wet cooling tower, it is assessed that raw water requirement shall be maximum upto 3600 m^3/h if fly ash is disposed in wet slurry form without recovery of ash pond water. After recovery of ash pond water commences, raw water drawal of 3000 m^3/h shall be adequate for plant operation with ash disposal in wet mode. It is expected that ash water recirculation system of the plant shall become functional within one year of plant operation. As such, plant consumptive water requirement shall be maximum upto 3600 m^3/h during first year of plant operation and 3000 m^3/h during subsequent period. However, if HCSD system is used for disposal of fly ash instead of wet slurry system, available blow down water shall be adequate for disposal of fly ash and bottom ash, and plant consumptive water shall be 3000 m^3/h right from beginning of plant operation.

ii) The plant raw water requirement worked out above is for normal sources of raw water with COC of CW system as 5.0. In case, treated sewage water or high TDS water is used as source raw water for the plant, the plant water requirement could be higher on account of different treatment scheme involved and/ or permissible COC being lower than 5.0. The raw water requirement could also be higher in case power plant is required to be provided with FGD plant. The assessment for requirement of raw water for above situations need to be worked out on case to case basis.

In some cases, it may be possible to increase COC of CW system above 5.0 based on quality of raw water and feasibility of cooling water treatment. In such case, plant consumptive water would reduce as per reduction in CT blow down water.

iii) In case of inland plant with dry cooling system, it is presumed that plant would be designed for fly ash disposal in dry mode right from initial period of plant operation, and water would be required for disposal of bottom ash only in wet slurry mode. Additional water to the tune of 200 m^3/h would be required for disposal of bottom ash without recovery of ash pond water. Assuming that ash water recirculation system would become functional within one year of plant operation, plant water requirement shall be maximum upto 750 m^3/h during first year of plant operation and 550 m^3/h during subsequent period. In case, HCSD system is used for fly ash disposal, additional raw water to the tune of 150 m^3/h would be required.

iv) In case waste water from CMB is treated using R.O. plant, the requirement of plant input water shall get reduced as per recovery of permeate water from the R.O. plant and scheme for utilization R.O. reject and other plant waste waters.

7.0 Techno- economics of Dry Cooling Systems

A techno- economic study has been carried out for application of dry cooling system in thermal power plants in India. Plant output data with dry cooling system has been obtained from M/s BHEL. Requisite data on dry cooling system has been obtained from M/s SPX/ Thermax and M/s GEA-EGI/ Energo - suppliers of dry cooling systems for thermal power plants. M/s SPX/ Thermax have furnished technical data, budgetary cost & power consumption data for their direct dry cooling air cooled condensers (ACC) utilizing mechanical draft fans and M/s GEA-EGI/ Energo have furnished technical data, budgetary cost & power consumption data for their indirect dry cooling Heller system employing direct contact jet condensers and natural draft hyperbolic tower. The details of the study carried out for plant with 500 MW size unit is enclosed as Annexure- 5.

Key findings of this study as per typical case considered are indicated as below:

i) As compared to wet cooling system, dry condenser cooling system results in reduction of unit output by about 7%. For example, the output of a conventional 500 MW unit with dry condenser cooling system shall reduce to about 465 MW. This is based on input data furnished by BHEL for the study.

ii) The heat rate of the unit with dry condenser cooling system is higher by about 7% in accordance with reduced output as indicated at (i) above. In terms of efficiency, thermal efficiency of the plant shall reduce by about 2.5 percentage points viz. typical thermal efficiency of 38 % for conventional 500 MW unit shall reduce to about 35.5% when provided with dry cooling system.

iii) Specific coal consumption of the unit shall increase by about 7%, and typical CO_2 emission from the plant shall also increase by about 7% (from 0.9 kg/kWh to 0.96 kg/kWh) with dry cooling system as compared to wet cooling system.

iv) As per CERC Regulations, auxiliary power consumption as %age of gross unit output for a conventional 500 MW unit is 6.5 % with IDCT and 6 % with NDCT based CW system. The auxiliary power consumption of the plant works out to about 6.8 % of gross output for plant with direct cooling air cooled condensers with mechanical draft fans and about 6.2 % for plant with indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower.

v) Taking reference cost for plant with wet cooling system as ₹ 5 crore/MW, the cost of the plant with dry cooling system would vary from ₹ 5.5 to 5.7 crore/MW.

vi) As per Tariff Model based on CERC Regulations for 2009- 14, the levelised tariff is expected to increase by about ₹ 0.30- 0.34/kWh for plant with dry cooling system located at load centre and about ₹ 0.20- 0.24/kWh for plant located at pit- head. In terms of percentage, the above increase amounts to about 8- 9% over base levelised tariff.

It may be seen from above that dry cooling systems are costly technologies and are not comparable to wet cooling system on techno- economic considerations.

8.0 Recommendations

8.1 As per the above study, the recommended plant consumptive water for different types of plants is indicated as below:-

Table- 2, Plant water requirement in m^3/h for 2x500 MW plant.

<table>
<tr><th rowspan="2">Sl. No.</th><th rowspan="2">Description</th><th colspan="2">In-land plants using indigenous coal</th><th rowspan="2">Sea water based coastal plants (fresh water requirement)</th></tr>
<tr><th>Plant with wet cooling tower</th><th>Plant with dry cooling system</th></tr>
<tr><td>1.</td><td>Water requirement for first year of plant operation</td><td>3600*
(3.6)</td><td>750[$]
(0.75)</td><td rowspan="2">400
(0.4)</td></tr>
<tr><td>2.</td><td>Water requirement during subsequent period</td><td>3000
(3.0)</td><td>550[$]
(0.55)</td></tr>
</table>

Figures within bracket indicate water requirement in m^3/h per MW of the plant.

Notes:

i) The above plant water requirements are for normal sources of raw water with COC of 5 for CW system. In case, treated sewage water or high TDS water is used as source for raw water or plant is required to be provided with FGD plant, the plant water requirement could be higher which needs to be worked out on case to case basis.

In some cases, it may be possible to increase COC of CW system above 5.0 based on quality of raw water and feasibility of cooling water treatment. In such case, plant consumptive water would reduce according to CT blow down reduction.

ii) * The indicated figure of 3600 m^3/h is for fly ash disposal in wet slurry mode. In case HCSD system is used for fly ash disposal, the plant consumptive water requirement shall be 3000 m^3/h ($3m^3/h$ per MW) right from first year of plant operation.

iii) \$ It is presumed that dry cooling system based plants would be designed with fly ash disposal in dry mode right from initial period of plant operation. In case, HCSD system is used for fly ash disposal, additional raw water to the tune of 150 m^3/h (0.15 m^3/h per MW) would be required.

iv) In case CMB water is treated using R.O. plant, the requirement of plant input water shall get further reduced as per recovery of permeate water and scheme for utilisation of waste waters including R.O. reject.

8.2 The plant water requirement values indicated at item 8.1 above have been worked out considering 500 MW size sub-critical units in the plant. The values in m^3/h per MW can also be used for assessing water requirement for super-critical plants having 660/ 800 MW size unit and sub-critical plants having unit size less than 500 MW up to 250 MW. For plants with unit size less than 250 MW, the water requirement could be more than that estimated on pro- rata basis as per above, and same needs to be worked out on case to case basis.

8.3 Dry condenser cooling system can be considered for the sites where availability of water is very scarce. In such case, the requirement of plant consumptive water shall reduce by about 80%. However, for typical Indian conditions, dry cooling system shall result in reduction of plant output by about 7% and correspondingly, gross heat rate shall increase by 7%. The capital cost per MW of the plant, shall increase by about 10%. These are indicative values as per data considered in the report. **Dry cooling systems, as such, are costly technologies and are not comparable to wet cooling system on techno-economic considerations. However, for sites where adequate quantity of water is just not available, dry cooling system offers possible solution for power plant installation with much reduced water requirement.**

Annexure- 1

List of participants of various meeting of the Committee & the Sub- group.

1. **CEA**
   i) Shri S. Seshadri, Member (Thermal)- Chairman
   ii) Shri Suresh Chander, Chief Engineer (TE&TD)- Member Secretary
   iii) Dr. L. D. Papney, Director
   iv) Shri Sanjay Sharma, Director
   v) Shri Rajesh Kohli, Assistant Director

2. **NTPC**
   i) Shri A. K. Sinha, GM
   ii) Shri Hemant Jethi, CDE
   iii) Mrs. S. Padmapriya, CDE
   iv) Shri Hitesh Singh, Sr. Er.

3. **BHEL**
   i) Shri P. K. Khurana, AGM
   ii) Shri A. K. Gilani, AGM
   iii) Shri Vishal Yadav, Manager

4. **RRVUNL**
   Shri O. P. Khandelwal, Dy Chief Engineer

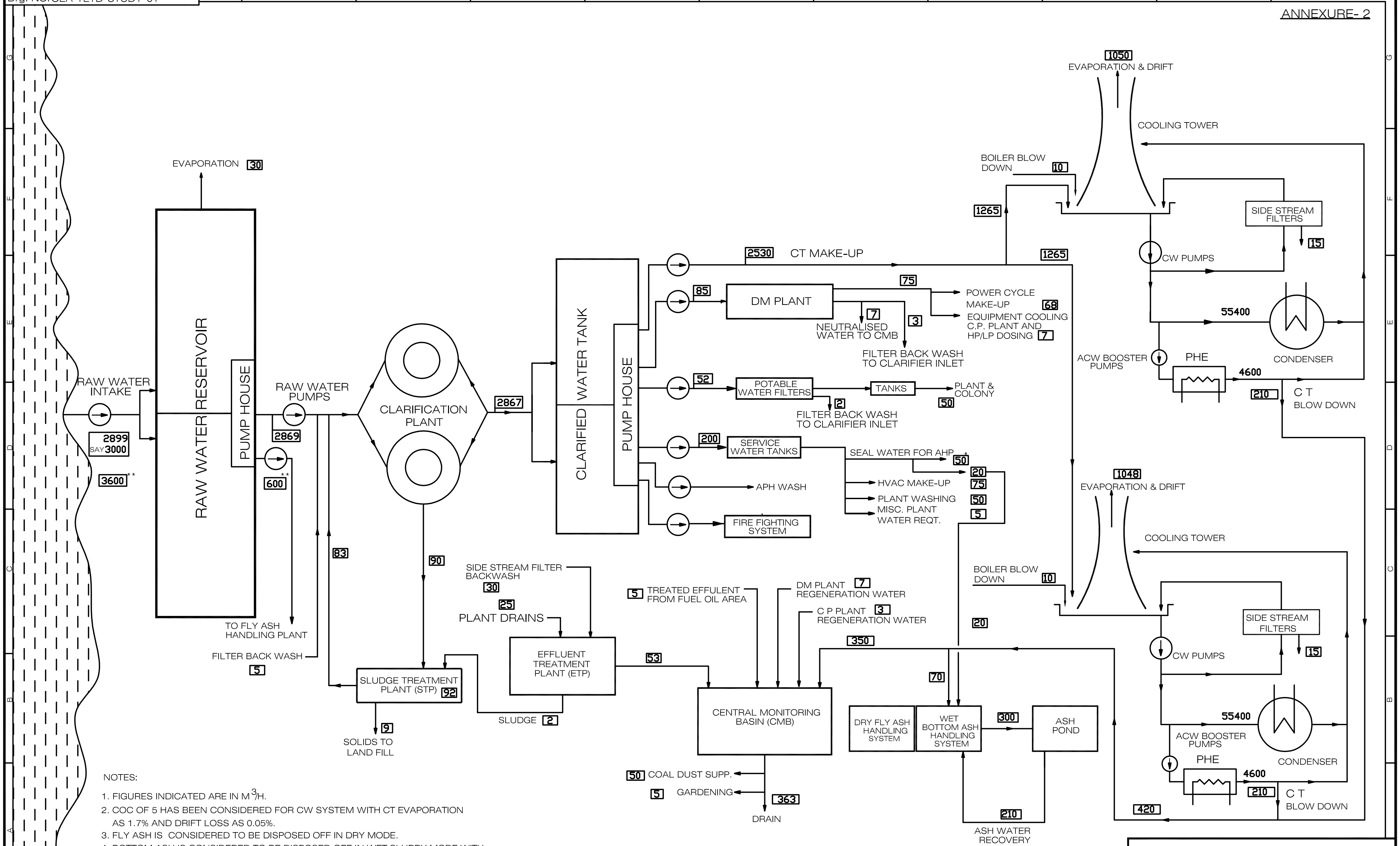
5. **MAHAGENCO**
   i) Shri A. T. Dawalekar, Director (Projects)
   ii) Shri V. P. Singh, E.D. (GP-II)
   iii) Shri Arvind Parate, G.M. (Civil)

6. **CESC**
   Shri S. K. Mukherjee, Senior Manager (ED-G's Establishment)

7. **TCE**
   Shri G. Satheesh Kumar, GM

Drg. NO. CEA-TETD-STUDY-01

ANNEXURE- 2



NOTES:

1. FIGURES INDICATED ARE IN M^3/H.
2. COC OF 5 HAS BEEN CONSIDERED FOR CW SYSTEM WITH CT EVAPORATION AS 1.7% AND DRIFT LOSS AS 0.05%.
3. FLY ASH IS CONSIDERED TO BE DISPOSED OFF IN DRY MODE.
4. BOTTOM ASH IS CONSIDERED TO BE DISPOSED OFF IN WET SLURRY MODE WITH RECYCLING OF ASH POND WATER.
5. RESERVOIR EVAPORATION CORRESPONDS TO RESERVOIR SIZE FOR 10 DAYS OF PLANT REQUIREMENT WITH WATER DEPTH AS 8M.
6. * APPLICABLE FOR FLY ASH DISPOSAL IN WET SLURRY MODE.
7. **APPLICABLE DURING INITIAL ONE YEAR PERIOD OF PLANT OPERATION WITH FLY ASH DISPOSAL IN WET SLURRY MODE WITHOUT ASH WATER RECOVERY.

FOR REFERENCE ONLY

S.No.	Zone	Date	Revision	Sign.		
					Designed	R. KOHLI
					Drn.	CECIL
					Recmed.	
					Sub.	
					Checked	R. KOHLI
					Appd.	Dr. L.D.PAPNEY
					Scale	NTS
					Date	AUG.' 2010

TYPICAL PLANT WATER BALANCE DIAGRAME FOR 2 X 500 MW COAL BASED TPP WITH WET COOLING TOWER

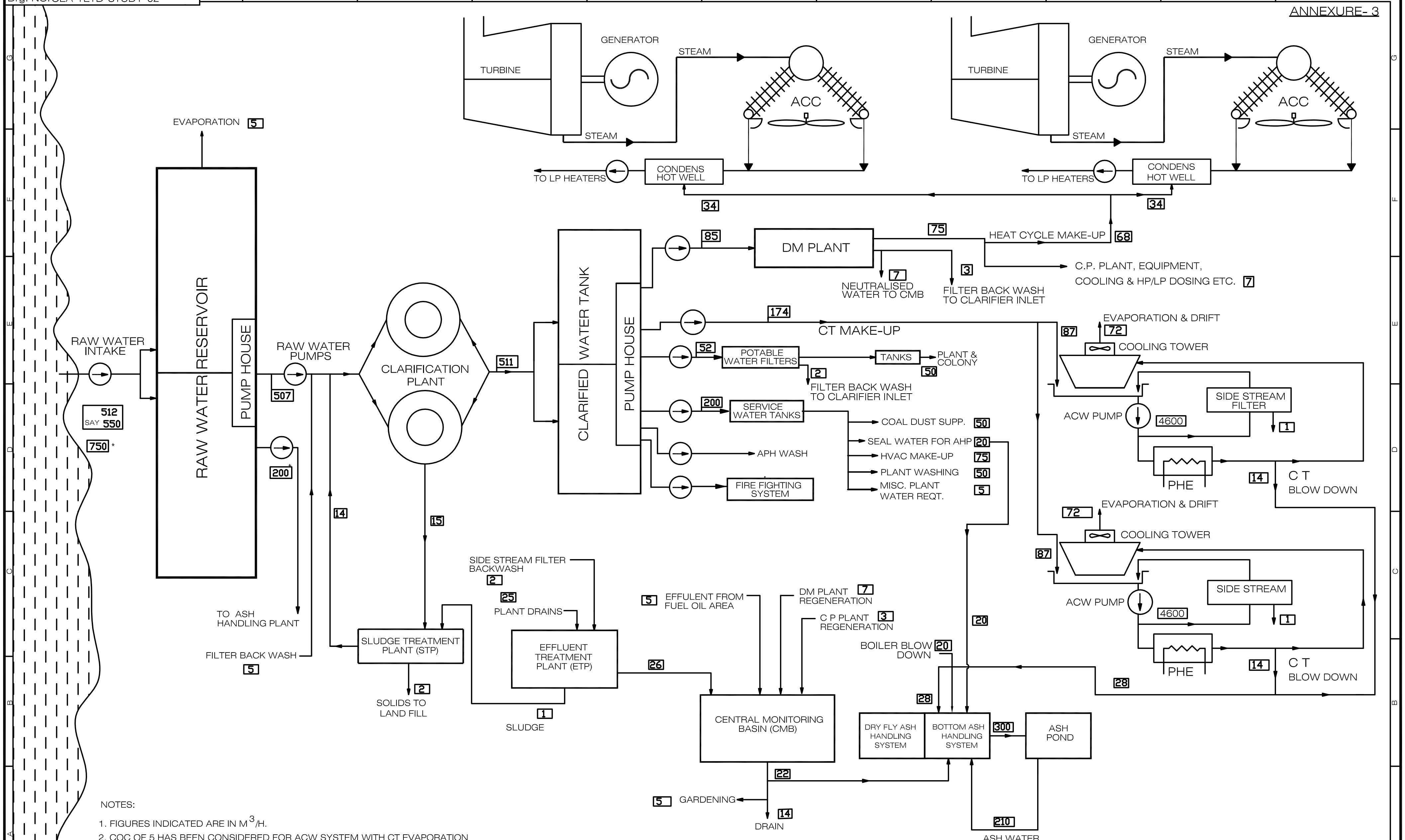
Central Electricity Authority

Drg. NO. CEA-TETD- STUDY - 01

849 X 594 Scale 1:1

Drg. NO. CEA-TETD-STUDY-02

ANNEXURE- 3



NOTES:

1. FIGURES INDICATED ARE IN M^3/H.
2. COC OF 5 HAS BEEN CONSIDERED FOR ACW SYSTEM WITH CT EVAPORATION AS 1.5% AND DRIFT LOSS AS 0.05%.
3. FLY ASH IS CONSIDERED TO BE DISPOSED OFF IN DRY MODE.
4. BOTTOM ASH IS CONSIDERED TO BE DISPOSED OFF IN WET SLURRY MODE WITH RECYCLING OF ASH POND WATER.
5. RESERVOIR EVAPORATION CORRESPONDS TO RESERVOIR SIZE FOR 10 DAYS OF PLANT REQUIREMENT WITH WATER DEPTH AS 8M.
6. * APPLICABLE DURING INTIAL ONE YEAR PERIOD WITH PLANT. OPERATION WITHOUT ASH WATER RECIRCULATION.

FOR REFERENCE ONLY

TYPICAL PLANT WATER BALANCE DIAGRAM FOR 2 X 500 MW COAL BASED TPP WITH DRY CONDENSER COOLING SYSTEM

Designed	R. KOHLI
Drn.	CECIL
Recmed.	
Sub.	
Checked	R. KOHLI
Appd.	Dr. L.D.PAPNEY
Scale	NTS
Date	AUG.' 2010

S.No.	Zone	Date	Revision	Sign.

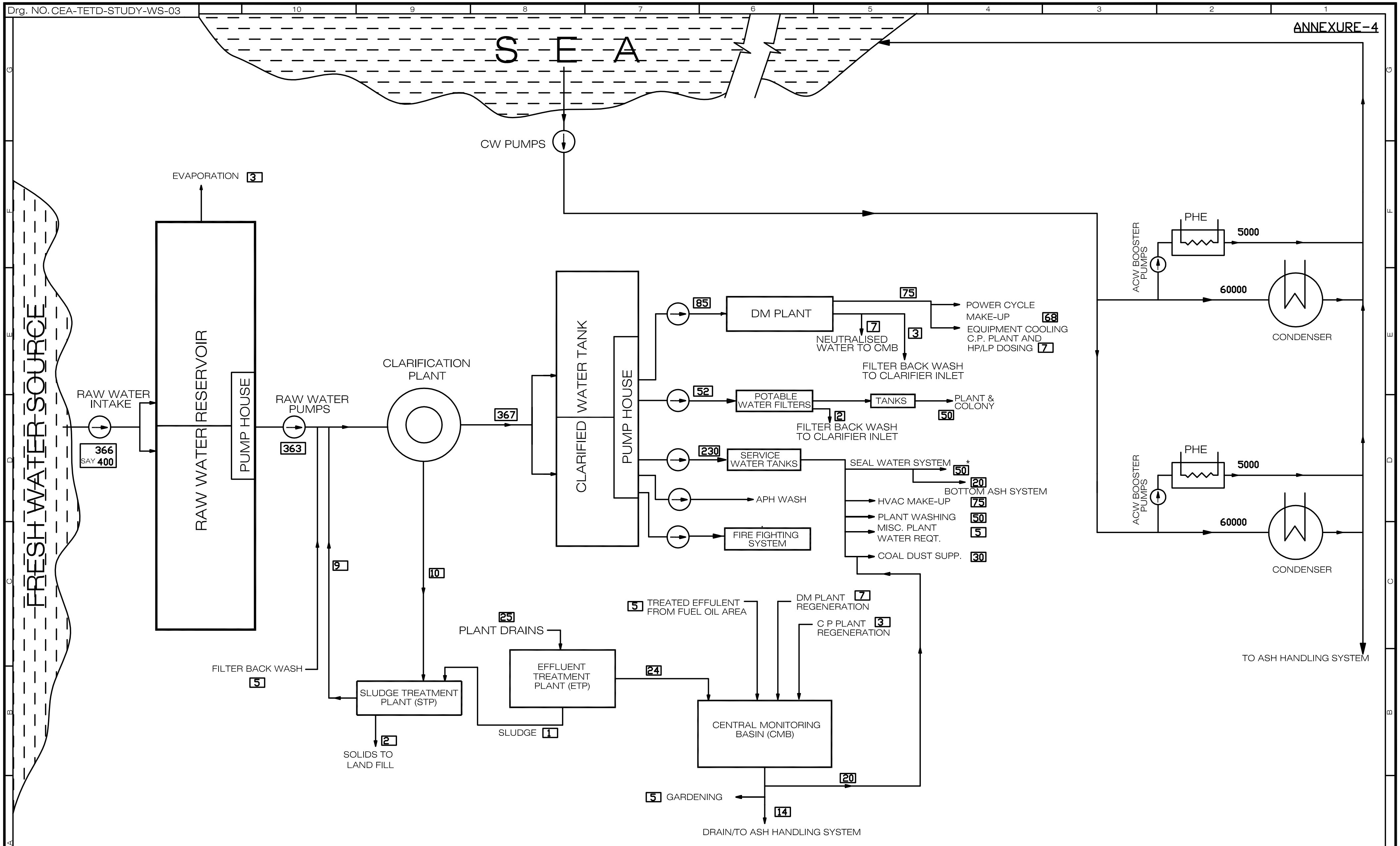
Central Electricity Authority

Drg. NO. CEA-TETD- STUDY-02

DO NOT SCALE, IF IN DOUBT PLEASE ASK

Drg. NO. CEA-TETD-STUDY-WS-03

ANNEXURE-4



NOTES:

1. FIGURES INDICATED ARE IN M^3/H.
2. RESERVOIR EVAPORATION CORRESPONDS TO RESERVOIR SIZE FOR 10 DAYS OF PLANT REQUIREMENT WITH WATER DEPTH AS 8M.
3. * APPLICABLE FOR FLY ASH DISPOSAL IN WET SLURRY MODE.

FOR REFERENCE ONLY

TYPICAL PLANT WATER BALANCE DIAGRAM FOR 2 X 500 MW COSTAL TPP

Designed	R. KOHLI
Drn.	CECIL
Recmed.	
Sub.	
Checked	R. KOHLI
Appd.	Dr. L.D.PAPNEY
Scale	NTS
Date	AUG.' 2010

S.No.	Zone	Date	Revision	Sign.

Central Electricity Authority

Drg. NO. CEA-TETD- STUDY-03

849 X 594 Scale 1:1

Annexure- 5

STUDY ON DRY CONDENSER COOLING SYSTEM FOR THERMAL POWER PLANTS

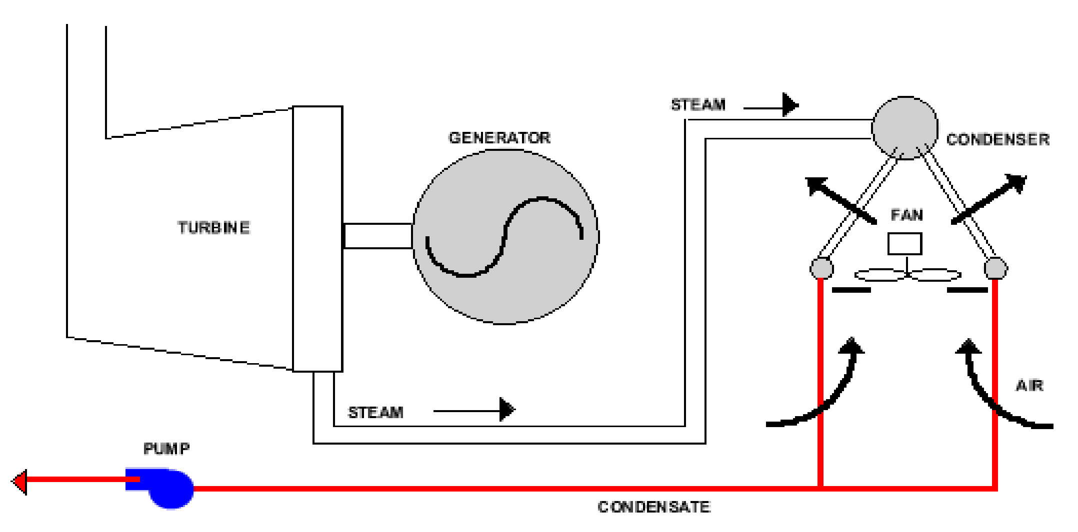
1.0 Type of Dry Cooling Systems

Dry cooling systems can be broadly classified in following two categories:-

i) Direct dry cooling system
ii) Indirect dry cooling system
iii) Hybrid cooling system

1.1 Direct Dry Cooling System

In direct dry cooling system, exhaust steam from LP turbine is directly cooled in a system of finned tubes by ambient air. Mechanical draft or natural draft in a hyperbolic tower can be used to move the air through fin tube heat exchange elements. Majority of direct dry cooling installations employ mechanical draft fans and are termed as air cooled condensers (ACC). A typical schematic of direct dry cooling ACC is indicated below:



DIRECT AIR-COOLED SYSTEM

The finned tubes are generally arranged in the form of an 'A' frame (or delta) over a forced draft fan with steam distribution manifold connected horizontally along the apex of 'A' frame. An ACC for a typical power plant consist of several such 'A' frame structures each comprising of several cells. Each cell consists of a number of finned tube bundles arranged in parallel along two walls of 'A' frame cell. Steam flowing down inside the tubes condenses due to the cooling effect of ambient air drawn over external finned surface of the tubes by the fans. The condensate drains from finned tubes into condensate manifolds and then drains into a condensate tank before being pumped to the conventional condensate cycle. To reduce pressure drop in steam conveying system, ACC needs to be installed close to the turbine hall. The photographs for typical installation of air cooled condenser are shown below:

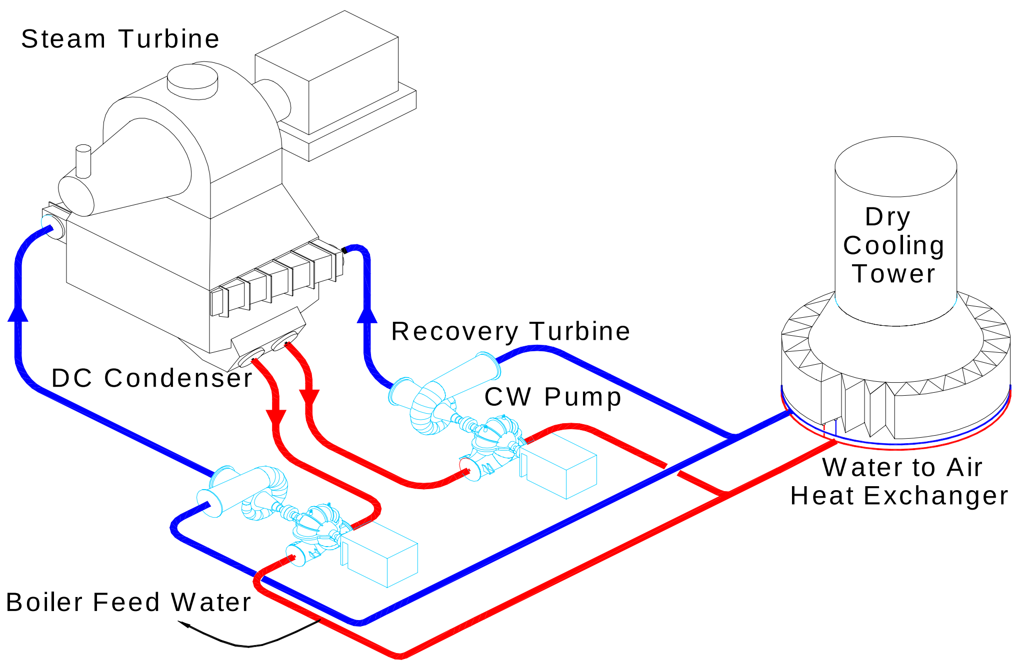
Air Cooled Condenser

Typical photographs of air cooled condenser

1.2 Indirect Dry Cooling System

In an indirect dry cooling system, exhaust steam from the turbine is cooled by water in a condenser which can be of surface type or direct content jet type, and hot water is cooled by air in finned tube bundles utilizing natural draft tower or mechanical draft fans. Generally, indirect dry cooling system is provided with natural draft tower. When conventional surface condensers are employed, steam and water circuits are independent and quality of condensate is not affected by the cooling water. However, the temperature of steam condensation is higher than hot water temperature as terminal temperature difference (TTD) is involved in surface condensers.

When jet condensers are employed, steam condensation takes place by direct contact with DM water, thus virtually eliminating any TTD between condensing steam and cooling water. A part of water from hot well is supplied to turbine cycle as condensate and rest of water is led to finned tube cooling deltas in natural draft tower and cold water is circulated back to the condenser. Since, condenser operates under vacuum, a hydraulic turbine is generally employed to recover the pressure head of water and reduce the pumping power of circulating water pumps. The following figure indicates schematic diagram of indirect dry condenser cooling system.



Schematic diagram of indirect dry condenser cooling system.

Heat exchanger elements in the form of V shaped cooling deltas are vertically arranged at base of the NDCT along its periphery. Cooling takes place by ambient air moving past the finned surface of cooling deltas drawn by buoyancy of hot air inside the tower shell. Because of water piping involved, these air cooled units can be located away from the main plant. The photograph for typical installation of an indirect dry cooling system is shown below:

Photograph of indirect dry condenser cooling system.

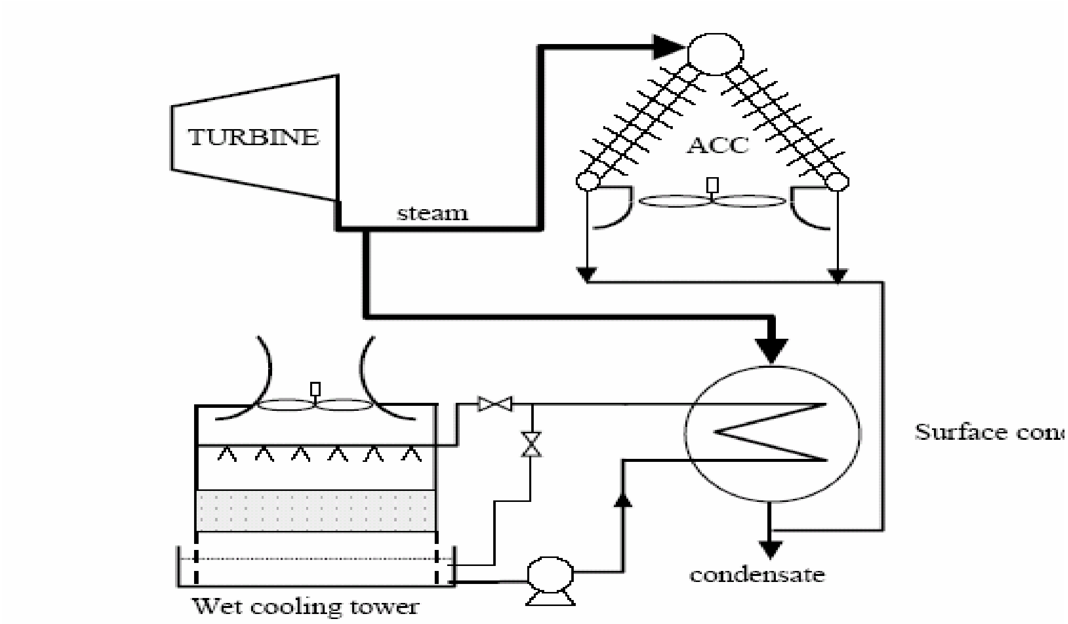
1.3 Hybrid Cooling System

Hybrid cooling system is a combination of dry cooling system and wet cooling system. There are basically two types of hybrid systems viz. dry cooling system with part wet system and, wet cooling system with part dry system.

A dry cooling system with part wet section principally consist of a dry cooling system with provision of spraying water on finned tube bundles. This arrangement is used for increasing/ maintaining unit output by evaporative cooling during extreme temperature conditions.

A wet cooling system with part dry system is basically useful for plants located in cold and humid climates for reducing visibility of plume from wet cooling tower exhaust. The system principally consists of a wet cooling tower with additional dry cooling section in its upper part for heating the saturated air coming out of wet cooling tower so as to reduce visibility of the plume.

The flexibility of hybrid arrangements can also be used for optimising unit output where quantity of water available is not adequate as for complete wet cooling system. The proportion of wet cooling part shall depend upon availability of water for the plant. In case of direct cooling ACC, a part of steam can be condensed in a conventional surface condenser using wet cooling tower, and in case of indirect cooling system, a part of hot DM water outlet from the condenser can be cooled in a heat exchanger employing secondary cooling water which in turn is cooled by a wet cooling tower.



Schematic diagram of hybrid cooling system with ACC.

2.0 Study on Dry Cooling Systems

The study of dry cooling system for its comparison with wet cooling system has been carried out for a typical 3x500 MW size coal based thermal power plant located at Jhajjar (Haryana State) in North India. The study has been carried out out considering both direct dry cooling system with mechanical draft fans and indirect dry cooling system using jet condensers and natural draft hyperbolic tower.

The comparison of dry cooling system with wet cooling system can be made either by considering same size of plant in both the cases with lower unit output available in case of dry cooling system on account of higher condenser pressure or by considering same unit output with requirement of higher size plant in case of dry cooling system. The case of same size plant is relatively easier for analysis as it requires modification in only LP turbine module as compared to the case of higher size plant requiring modification in LP turbine module as well as upscaling of all plant equipment and systems. In the present case, study has been carried out considering same size of BTG as that of conventional BTG for wet cooling plant with modification required in LP turbine module and corresponding turbine cycle optimisation.

2.1 Selection of Design Conditions

Selection of design ambient temperature is an important aspect which has a bearing on required size of dry cooling equipment. Design ambient temperature for dry cooling systems is generally selected keeping in view the annual profile of ambient temperature variation at the site. During the period when ambient temperature is higher than the design value, the available output shall be lower than rated output of the turbine and vice versa. In the present study, design ambient temperature has been selected as an appropriate temperature which is not exceeded by more than 10% of the time during four summer months of the year. Thus, available output of the unit shall be more than its rated output except for 10% of the time during four summer months when ambient temperature is higher than selected design temperature. For the purpose of study, the design dry bulb temperature for Jhajjar site has been estimated from climatological table for Delhi Station which is nearest meteorological station for the plant. Based on monthly mean values of daily temperature at 8:00 Hrs, daily temperature at 15:00 Hrs, daily maximum temperature and daily minimum temperature, an appropriate temperature value which would not be exceeded by more than 10% time in four summer months is considered as 38 ^{0}C.

Four options of condenser pressures as 0.18, 0.20, 0.22 and 0.24 ata (a) have been considered for dry cooling system which corresponds to initial temperature difference (ITD) values of about 20, 22, 24 and 26 deg C respectively over design ambient temperature of 38 ^{0}C.

2.2 Input Data

For different design values of condenser pressure, the turbine cycle heat balance diagrams (HBDs) for TMCR & VWO conditions with modification of LP turbine module for suitability as per higher condenser pressure have been developed by M/s BHEL. The HBDs for TMCR condition for the condenser pressure of 0.18, 0.20, 0.22 and 0.24 ata (a) are enclosed as Appendix- 1 to 4. The available unit output, and turbine exhaust steam data required as design input by suppliers of dry cooling system have been obtained from the HBDs as below:

Table- A, Input data for dry cooling system.

Sl. No	**Description**	**Turbine exhaust pressure, ata (a)**			
		0.18	**0.20**	**0.22**	**0.24**
i)	Turbine output, MW	464.4	463.7	462.8	461.9
ii)	Shortfall in gross output, %	7.12	7.26	7.44	7.62
iii)	LP turbine exhaust steam flow, t/h	992.3	994.6	996.6	998.4
iv)	LP turbine exhaust steam flow enthalpy, kcal/kg	600.2	600.4	600.9	601.6
v)	BFP turbine exhaust steam flow, t/h	78.4	80.4	82.4	84.2
vi)	BFP turbine exhaust steam enthalpy, kcal/kg	606.7	609.7	612.5	615.1
vii)	Design condenser heat load, million kcal/h (MWt)	581.7 (676.5)	582.1 (677)	582.7 (677.7)	583.6 (678.7)

It may be seen that output of conventional 500 MW unit is reduced by about 7% considering LP turbine modules currently available with BHEL for higher condenser pressure range as above. This shortfall in unit output is expected to reduce for well designed LP turbine module to be used/ developed for an actual case of unit to be supplied with dry cooling system. As such, the HBDs are considered to be preliminary and indicative for the purpose of this study. In this connection it may be mentioned that as per software studies carried out by NTPC, the expected shortfall in unit output for condenser pressure of 0.18 ata (a) amounts to about 4% and for condenser pressure of 0.24 ata (a) about 6%. However, in this report, the values as furnished by BHEL have been considered for evaluating the impact of dry cooling systems.

For the input data as above, the details of dry cooling system equipment, power consumption data and budgetary cost etc. has been obtained from two suppliers of dry cooling systems. In this respect, M/s SPX/ Thermax have furnished the technical data, power consumption and equipment cost of required air cooled condenser for all the four values of condenser pressures. M/s GEA-EGI/ Energo have responded for broad technical data, cost details and power consumption of required indirect dry cooling system for condenser pressures of 0.22 and 0.24 ata (a) only.

The technical data, power consumption values, operating expenses on chemical etc. and cost details of other relevant plant systems of 3x500 MW units have been finalized jointly by CEA, NTPC and BHEL.

2.3 Assumptions

i) The indicated unit output for plant with dry cooling system is corresponding to design ambient temperature of 38^{o}C. As per climatological table for Delhi Station, the ambient dry bulb temperature at the plant site is expected to vary in the range from minimum of 1.4 ^{0}C to maximum of 45 ^{0}C. In line with criterion adopted for selection of design temperature, the ambient temperature shall exceed design temperature only during 10% time of four summer months, and for rest of the year it shall be below design temperature. As such, weighted average output of the unit with dry cooling system shall be higher than the rated output values indicated in Table- A above.

The impact of ambient temperature variation on unit output needs to be worked out as per detailed temperature data of the site and performance curve of dry condenser cooling system in conjunction with performance curve of steam turbine . The performance curve of steam turbine in the form of condenser back pressure v/s turbine output, as furnished by BHEL is enclosed as Appendix- 5. The performance curves of individual dry cooling systems as furnished by M/s SPX/ Thermax and M/s GEA-EGI/ Energo are enclosed as Appendix- 6 to 9 and Appendix- 10 respectively. However, no detailed calculations have been made in the present study, and weighted unit output has been taken as its rated output increased by a factor of 0.5% to account for impact of annual temperature variation. The relative impact of wet bulb temperature variation on output of steam turbine for wet cooling system has been neglected.

ii) Plant raw water both for wet cooling system and dry cooing system is considered to be drawn from water source located at a distance of about 18 km from the plant. The consumptive water requirement of conventional plant with dry disposal of fly ash and wet disposal of bottom ash has been considered as 4500 m^3/h (3 m^3/h per MW). Water requirement is taken as 5400 m^3/h (3.6 m^3/h per MW) for initial one year period of plant operation with additional water required for wet disposal of fly ash without recirculation of ash pond water. As such, raw water intake, raw water supply system and raw water reservoir are considered to be sized as per water requirement of 5400 m^3/h. However, PT plant sizing and operating expenses on raw water, auxiliary power and dosing chemicals has been taken as per water requirement of 4500 m^3/h. For the case of plant with dry condenser cooling system, plant consumptive water requirement is assessed as 1125 m^3/h (0.75 m^3/h per MW) for first year of plant operation and 825 m^3/h (0.55 m^3/h per MW) for subsequent period. The capacity of raw water reservoir for both the cases has been considered as per adequacy for 45 day's plant requirement in line with data for Jhajjar TPP.

iii) For plant with conventional wet cooling system, option of both NDCT and IDCT has been considered for cooling of hot water from CW and ACW systems. For the case of plant with dry cooling system, provision of a small IDCT has been considered for cooling of hot water from ACW system.

iv) The plant data, power consumption and cost details of raw water intake system, raw water supply system, water treatment system and cooling water system for plant with conventional wet cooling system have been taken as per details available for NTPC's 3x500 MW plant under installation at Jhajjar. The cost of these plant systems as applicable for dry cooling system have been assessed from corresponding costs for plant with wet cooling system on pro- rata basis as per capacity/ size and applying power index of 0.8. For assessing cost of raw water reservoir, value of power index has been taken as 1.0.

v) For assessing the impact of dry cooling system on tariff, the following reference values have been considered for plant with wet cooling system:

- Capital cost : ₹ 5 crore/MW
- Auxiliary power consumption : 6.5 % with IDCT, and 6.0% with NDCT based CW system
- O&M cost : ₹ 13 lakh/MW per year
- Unit heat rate : 2425 kcal/kWh

Other important assumptions of tariff calculations are indicated as below:

- Debt/ equity ratio : 70 : 30
- Interest rate : 11%
- Return on equity : 15.5%
- Plant PLF : 85%
- Fuel escalation : 6 %
- O&M escalation : 5%
- Discount rate : 9.35%
- Depreciation rate : 5.28%

2.4 Formulation of the Study

The detailed formulation of the study indicating impact of reduced unit output, cost of individual equipment/ systems, auxiliary power consumption and operating expenses on chemicals etc. are indicated in Appendix- 11.

3.0 Layout and Area Requirement Aspects

Direct cooling air cooled condensers involved cooling of turbine exhaust steam in finned tube bundles using ambient air. These air cooled units need to be located adjacent to the turbine hall so that length of steam header and accordingly pressure drop between ACC and LP turbine exhaust is minimum. In case of indirect dry cooling system i.e. in Heller system, jet condensers are provided for steam condensation and natural draft tower for cooling the hot water can be conveniently located away from the turbine hall.

For a given ambient design temperature, the requirement of foot print area for dry cooling system varies considerably with selected condenser pressure/ initial temperature difference (ITD). As per data furnished by M/s SPX/ Thermax for the present study, the area required for installing direct cooling air cooled condenser for 500 MW size unit varies from 2.8 acre (103mx110m) for condenser pressure of 0.18 ata (a) to 2 acre (103mx78m) for condenser pressure of 0.24 ata (a). For indirect dry cooling Heller system, the diameter at heat exchanger outskirt for natural draft tower as indicated by M/s GEA-EGI/Energo is 171 m (area 5.7 acre) for condenser pressure of 0.22 ata (a) and 155 m (area 4.7 acre) for condenser pressure of 0.24 ata (a).

The area requirement of the power plant with dry cooling system needs to be compared with wet cooling system considering total area required for plant water system and cooling system facilities. Since, requirement of plant raw water in case of dry cooling system is reduced to about 20% of that required for wet cooling system, the sizes of various water system facilities such as raw water intake system, corridor for raw water supply piping, raw water reservoir, water pre- treatment plant and clarified water storage tank shall reduce considerably. Further, CW pump house & forebay, cooling towers &

cold water channel, CW ducts, chlorination plant, side stream filters & chemical doing system for condenser cooling system shall also not be required with dry cooling system. However, in case of Heller system, circulating water pumps and recovery turbines are required to be provided.

The requirement of area inside and outside the power plant boundary depends upon site specific factors such as type of raw water source and its distance from the plant, requirement for storage of raw water in terms of number of days of plant operation, type and design parameters of cooling system considered. The same needs to be worked out case to case basis. However, it is expected that overall area required for plant water system and cooling system facilities shall be lower in case of dry cooling system as compared to that for wet cooling system.

4.0 Conclusions

4.1 The comparison of dry cooling systems for different condenser design pressure values has been made considering NDCT as well as IDCT for wet cooling system. Based on plant details, power consumption values and budgetary cost data used in the study, the following conclusions are derived:

i) As compared to wet condenser cooling system, dry condenser cooling system results in reduction of unit output by about 7%. For example, the output of a conventional 500 MW unit with dry condenser cooling system shall reduce to about 465 MW. This is as per data furnished by BHEL for the purpose of study.

ii) The heat rate of the unit with dry condenser cooling system shall be higher by about 7% in accordance with reduced output as indicated at (i) above. In terms of efficiency, thermal efficiency of the plant shall reduce by about 2.5 percentage point viz. typical thermal efficiency of 38 % for conventional 500 MW unit shall reduce to about 35.5% when provided with dry cooling system.

iii) The specific coal consumption and accordingly CO_2 emission from the unit shall increase by about 7%. With dry cooling system, typical CO_2 emission from the plant shall increase from say 0.9 kg/kWh to 0.96 kg/kWh.

iv) Auxiliary power consumption as percentage of gross unit output for a conventional 500 MW unit with turbine driven BFPs is 6.5 % with IDCT and 6 % with NDCT based CW system. The corresponding auxiliary power consumption of the plant with direct cooling air cooled condenser employing mechanical draft fans is about 6.8 % and with indirect cooling system employing jet condensers and natural draft tower is about 6.2 %.

v) As per budgetary costs furnished by suppliers of dry cooling systems, the cost of installation of air cooled condenser for a 500 MW size unit is likely to vary in the range of ₹ 250 crore for condenser pressure of 0.18 ata (a) to ₹ 190 crore for condenser pressure of 0.24 ata (a). For indirect cooling system employing jet condensers and natural draft tower, cost of installation is likely to be about ₹ 325 crore for condenser pressure of 0.22 ata (a) and ₹ 300 crore for condenser pressure of 0.24 ata (a).

vi) Considering above and taking reference cost for plant with wet cooling system as ₹ 5 crore/MW, the cost of the plant with dry cooling system would vary from ₹ 5.5 to 5.7 crore/MW.

vii) The O&M expenses of ₹ 13 lakh/MW admissible as per currently applicable CERC norms may be reduced to ₹ 12.1 lakh/MW for the plants based on dry cooling system. Though the overall O&M expenses would reduce due to reduction in water charges and cost of chemicals but when spread over reduced output in case of dry cooling, O&M expenses per MW works out almost similar.

4.2 The impact of dry cooling system on tariff has been estimated for plant locations at load centre and pit head using CERC tariff model for 2009- 14. The present cost of coal and its GCV have been taken as ₹ 2300/ton and 4000 kcal/kWh respectively for load centre site and ₹ 1000/ton and 3600 kcal/kWh respectively for pit head site. The results of tariff calculation are indicated at Appendix- 12 to 15. As per these, typical impact of dry cooling system on levelised tariff is summarized as below:

Table- B, Impact of dry cooling system on levelised tariff.

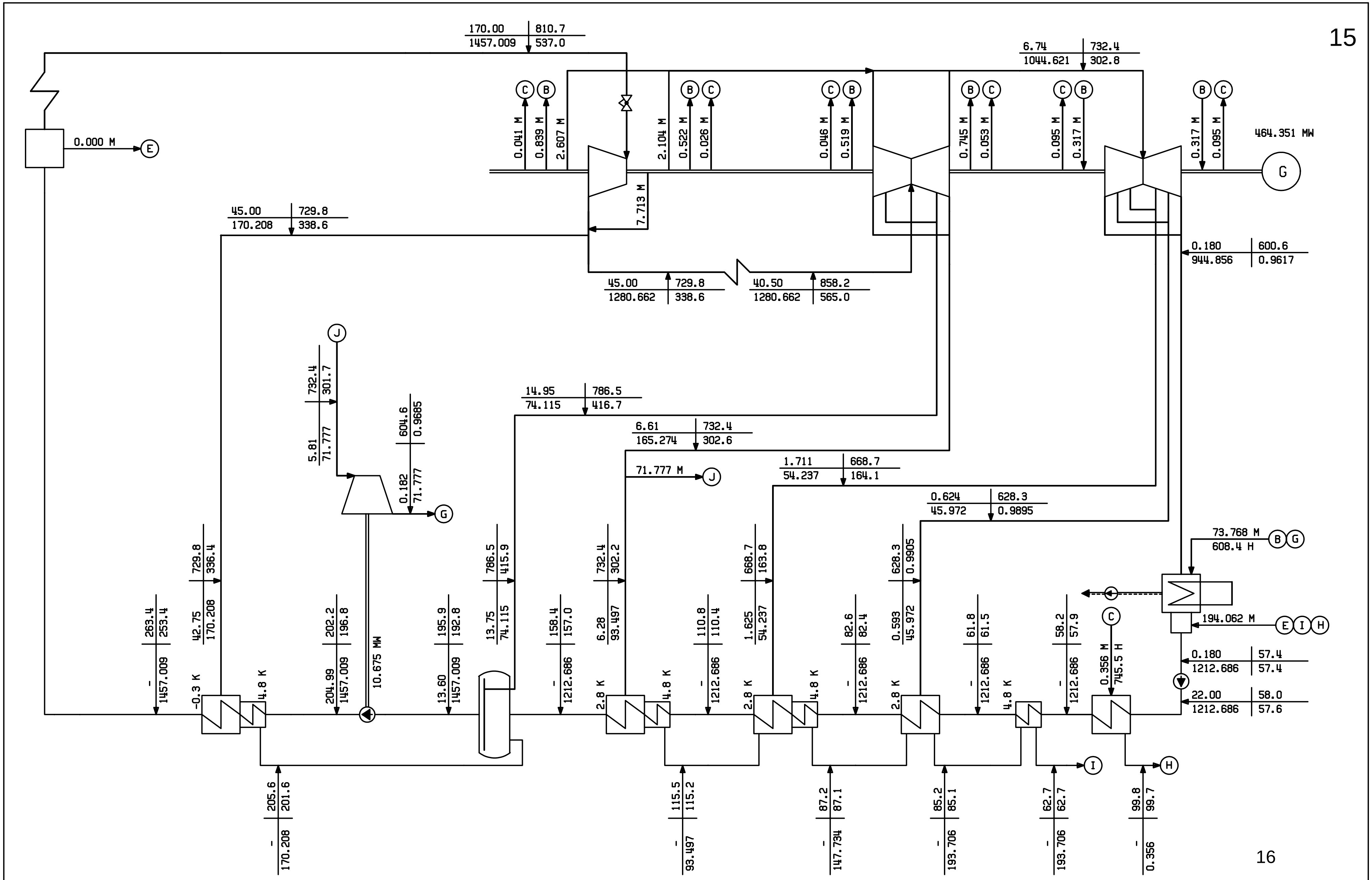
Description	Differential Levelised Tariff (₹/kWh)						
	Wet cooling system	Direct dry cooling system				Indirect dry cooling system	
		0.18 ata(a)	0.20 ata(a)	0.22 ata(a)	0.24 ata(a)	0.22 ata(a)	0.24 ata(a)
Plant at load centre	Base (NDCT)	0.31	0.30	0.31	0.30	0.34	0.33
	Base (IDCT)	0.32	0.31	0.31	0.30	0.34	0.34
Plant at pit- head	Base (NDCT)	0.21	0.20	0.20	0.19	0.23	0.23
	Base (IDCT)	0.21	0.20	0.20	0.20	0.24	0.23

It may be seen from above that levelised tariff is expected to increase by about ₹ 0.30- 0.34/kWh for plant located at load centre and about ₹ 0.20- 0.24/kWh for plant located at pit- head. In terms of percentage, the above increase amounts to about 8- 9% over base levelised tariff of about ₹ 4/kWh for load center plant and ₹ 2.6/kWh for pit head plant.

4.3 Though as per the above results, indirect dry cooling system results in slightly higher impact on tariff, it may be mentioned that above results are based on budgetary costs and power consumption values furnished for the study. Both the technologies are considered suitable for Indian conditions, and specific choice needs to be made on case to case basis considering actual equipment cost, power consumption and site specific aspects.

4.4 Direct cooling ACC needs to be located adjacent to the turbine hall so as to keep pressure drop between ACC and LP turbine to minimum. In case of indirect dry cooling system i.e. in Heller system, natural draft tower for cooling the hot water can be conveniently located away from the turbine hall. As regards requirement of area for water system and cooling system facilities, it is expected that total area required inside and outside the plant shall be lower for the plant provided with dry cooling system as compared to that for plant provided with wet cooling system.

4.5 **It may be seen that dry cooling systems are costly technologies and are not comparable to wet cooling system on techno- economic considerations. However, for sites where adequate quantity of water is just not available, dry cooling system offers possible solution for power plant installation with much reduced water requirement.**



PRELIMINARY HEAT BALANCE DIAGRAM

(ONLY FOR STUDY)

AT	KCAL/KG
T/H	°C (X)

M.... MASS FLOW.... T/H

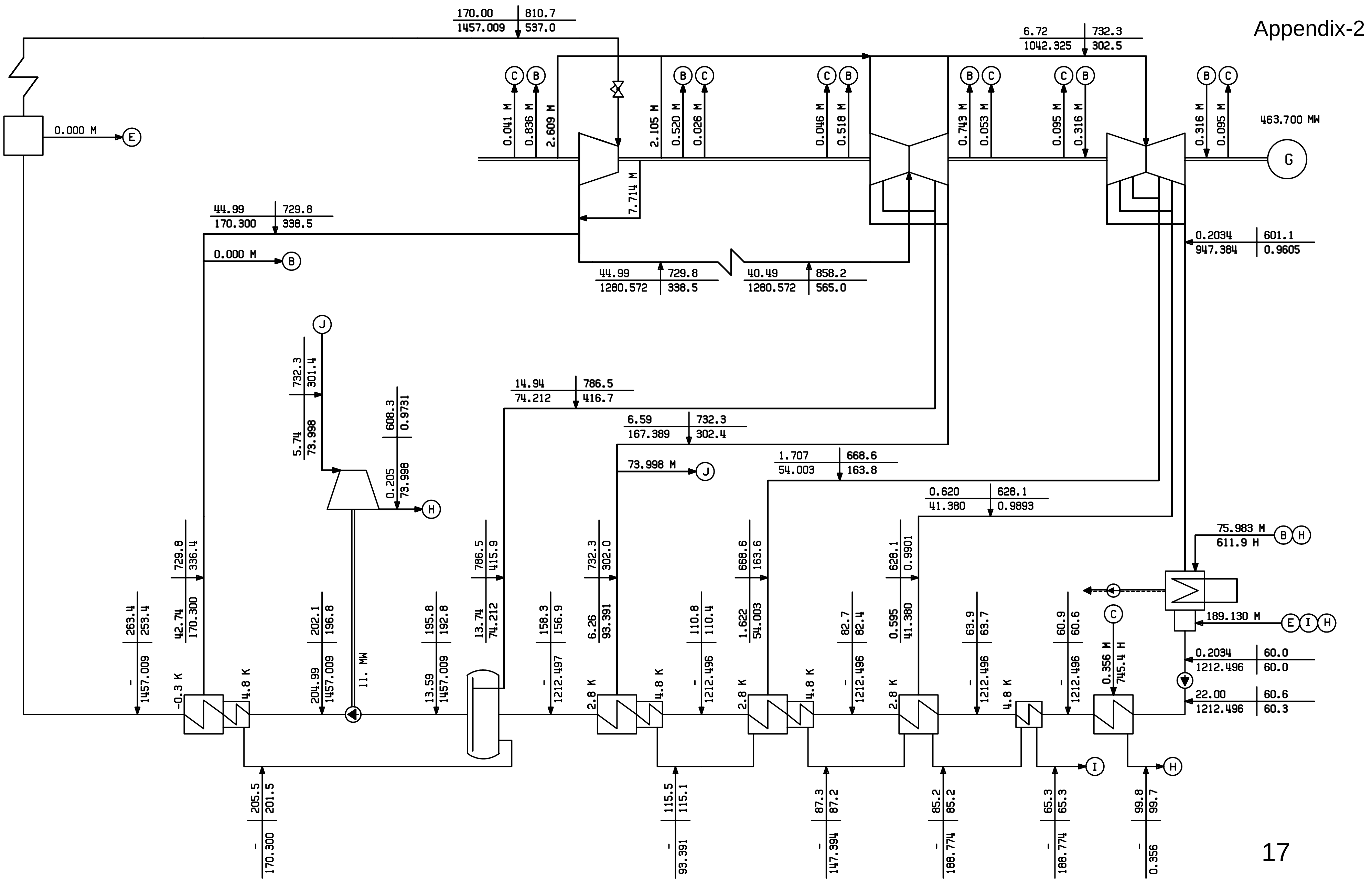
H.... ENTHALPY..... KCAL/KG

BHARAT HEAVY ELECTRICALS LTD
PROJECT ENGINEERING MANAGEMENT
NEW DELHI

AIR COOLED THERMAL POWER STN
2 x 480 MW UNITS/ ALL ADVANCED BLADING
480MW 0% MU 0.1800 ATA BACK PR.

PREP			
CHKD			
APPD		JOB NO	888
DATE	05.10.09	DRG NO	PE - DC - 888 - 100- REV 00

Appendix-2



17

AT	KCAL/KG
T/H	°C (X)

M.... MASS FLOW.... T/H
H.... ENTHALPY..... KCAL/KG

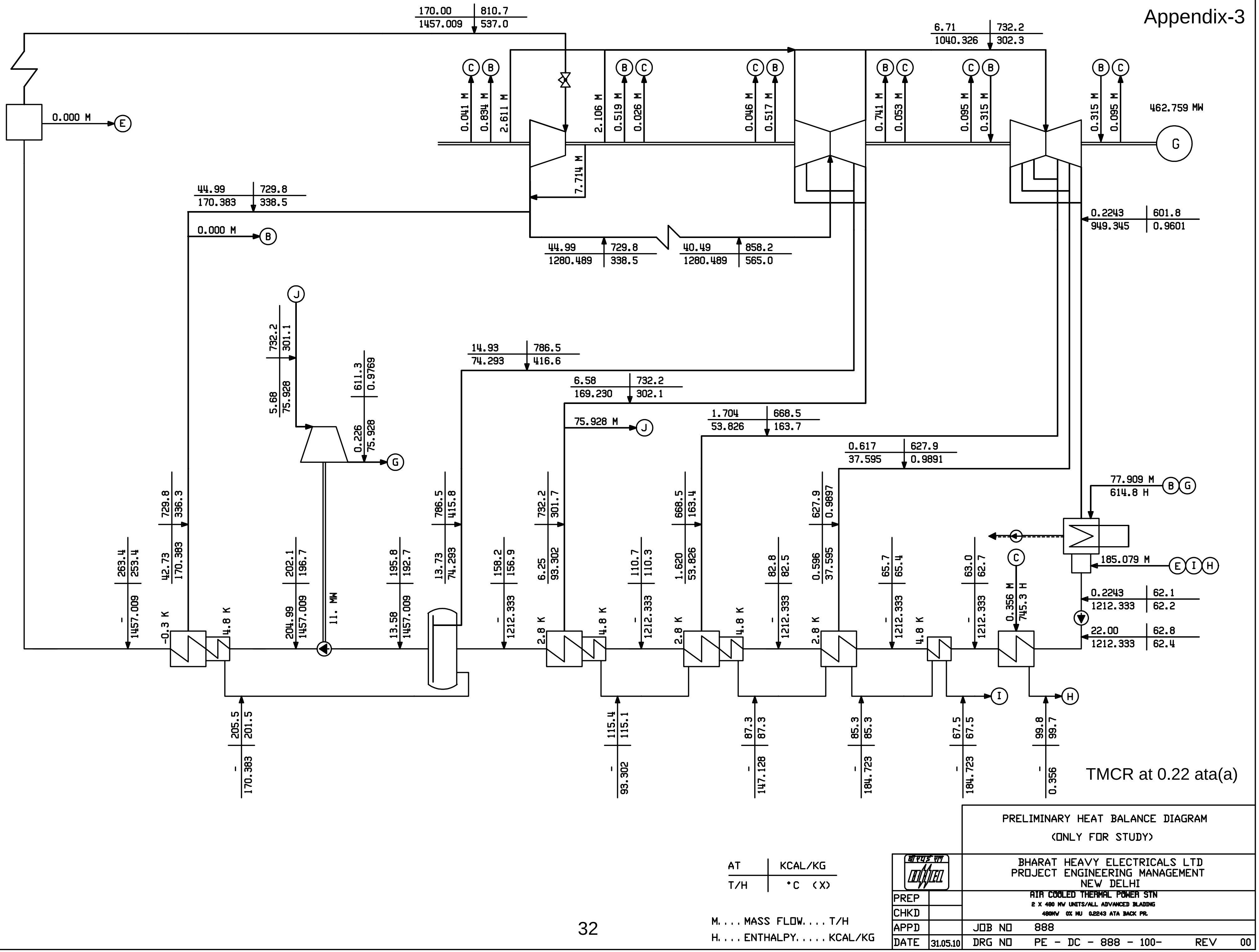
PRELIMINARY HEAT BALANCE DIAGRAM
(ONLY FOR STUDY)

BHARAT HEAVY ELECTRICALS LTD
PROJECT ENGINEERING MANAGEMENT
NEW DELHI

AIR COOLED THERMAL POWER STN
2 X 480 MW UNITS/ALL ADVANCED BLADING
480MW 0% MU 0.2034 ATA BACK PR.

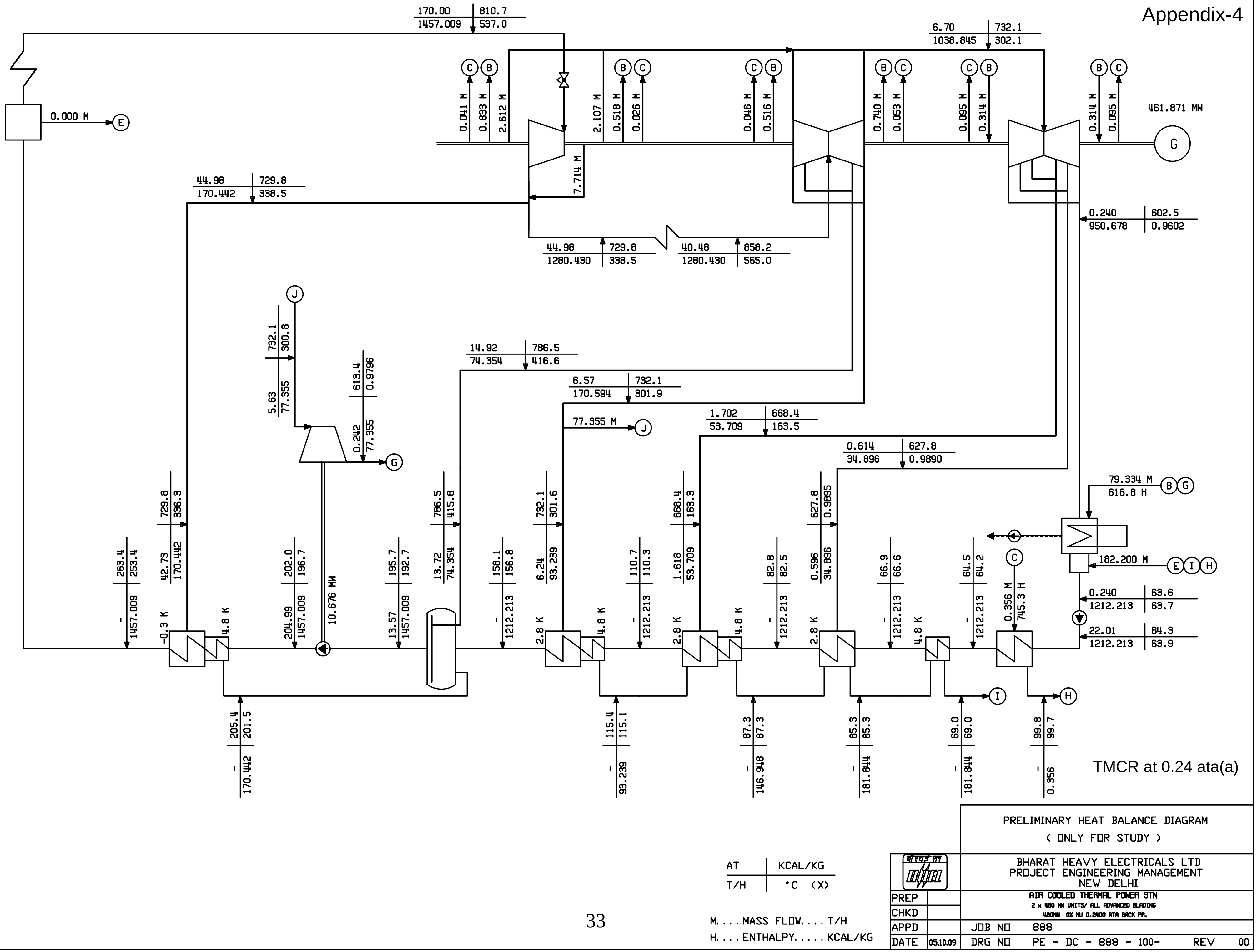
PREP			
CHKD			
APPD		JOB NO	888
DATE	31.05.10	DRG NO	PE - DC - 888 - 100- REV 00

Appendix-3



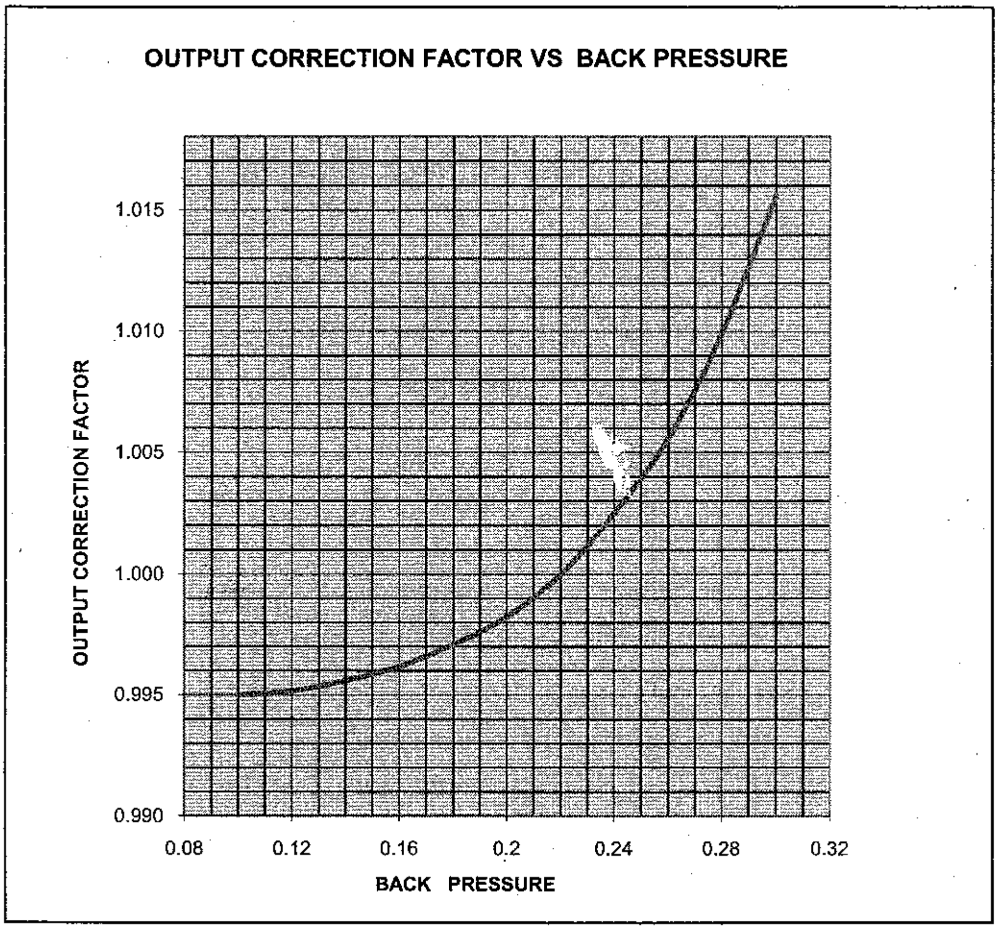
462.759 MW
TMCR at 0.22 ata(a)
PRELIMINARY HEAT BALANCE DIAGRAM
(ONLY FOR STUDY)
BHARAT HEAVY ELECTRICALS LTD
PROJECT ENGINEERING MANAGEMENT
NEW DELHI
AIR COOLED THERMAL POWER STN
2 X 460 MW UNITS/ALL ADVANCED BLADING
460MW 0% MU 0.2243 ATA BACK PR.
PREP
CHKD
APPD
DATE 31.05.10
JOB NO 888
DRG NO PE - DC - 888 - 100- REV 00
AT | KCAL/KG
T/H | °C (X)
M.... MASS FLOW.... T/H
H.... ENTHALPY..... KCAL/KG

Appendix-4



461.871 MW
0.000 M
7.714 M
77.355 M
10.676 MW
79.334 M
616.8 H
182.200 M
TMCR at 0.24 ata(a)
AT | KCAL/KG
T/H | °C (X)
M.... MASS FLOW.... T/H
H.... ENTHALPY..... KCAL/KG
PRELIMINARY HEAT BALANCE DIAGRAM
(ONLY FOR STUDY)
BHARAT HEAVY ELECTRICALS LTD
PROJECT ENGINEERING MANAGEMENT
NEW DELHI
AIR COOLED THERMAL POWER STN
2 x 480 MW UNITS/ ALL ADVANCED BLADING
480MW 0% MU 0.2400 ATA BACK PR.
PREP
CHKD
APPD
DATE 05.10.09
JOB NO 888
DRG NO PE - DC - 888 - 100-
REV 00

FOR DRY COOLING SYSTEM



FOR INFORMATION ONLY

	PREP: ANUJ VERMA	BHEL PEM
DEPARTMENT: MSE	CHECKED: VIKAS KUKREJA	
NEW DELHI	APPD. : ANIL KUMAR	

SPX COOLING TECHNOLOGIES

SPX Cooling Technologies Belgium

AIR COOLED STEAM CONDENSER (ACC)

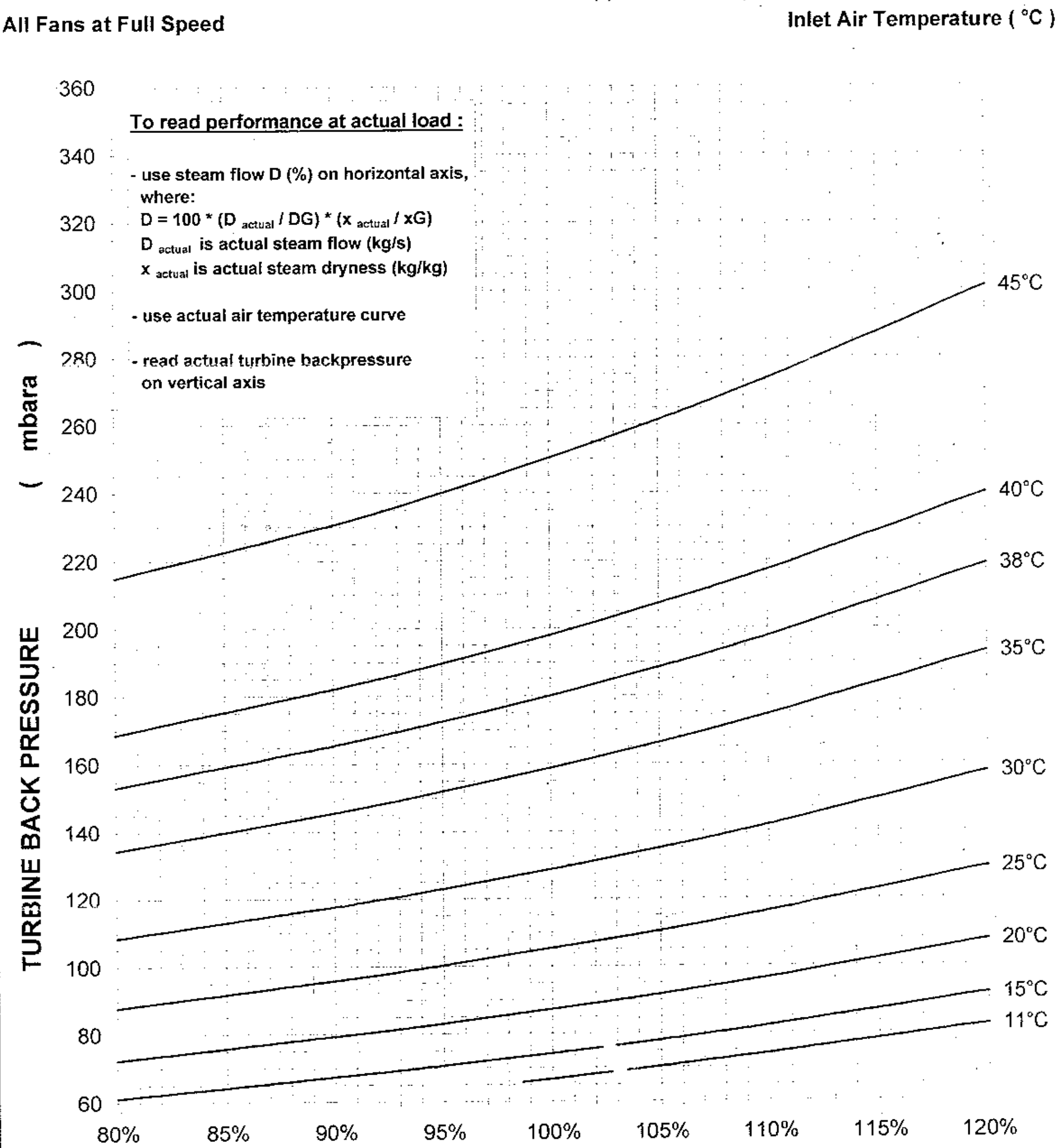
Client	CEA	Document Reference 09-101-0162-032_a3_PCUB0001
Location	Jhajjar (India)	
Document	**PERFORMANCE CURVES FOR CONSTANT DRYNESS**	Proposal Nr 09-101-0162-032_a3

DESIGN CONDITIONS

Steam Flow	DG	297.417 kg/s	Steam Dryness	xG	0.962 kg/kg
Back Pressure	PG	180. mbara	Barom. Pressure	bG	982.4 mbara
Air Temperature	tLG	38. °C	Wind Speed (*) (max.)		3. m/s

(*, 1 m above top manifold level

All Fans at Full Speed



Steam Flow (%)

Steam flow range for contractual acceptance test:
90% - 110% (according to VGB R131 Me 1997)

Revision	-	A	B	C	D	E	F
Date	20-nov-09						
Issued	QVA						
Approved							
Released	MBO						
Status	PRE						

Program N° 37 Perftab3-7 Ver. 3 Rev. 7 - 09 Dec 2008

SPX Cooling Technologies Belgium

SPX COOLING TECHNOLOGIES

AIR COOLED STEAM CONDENSER (ACC)

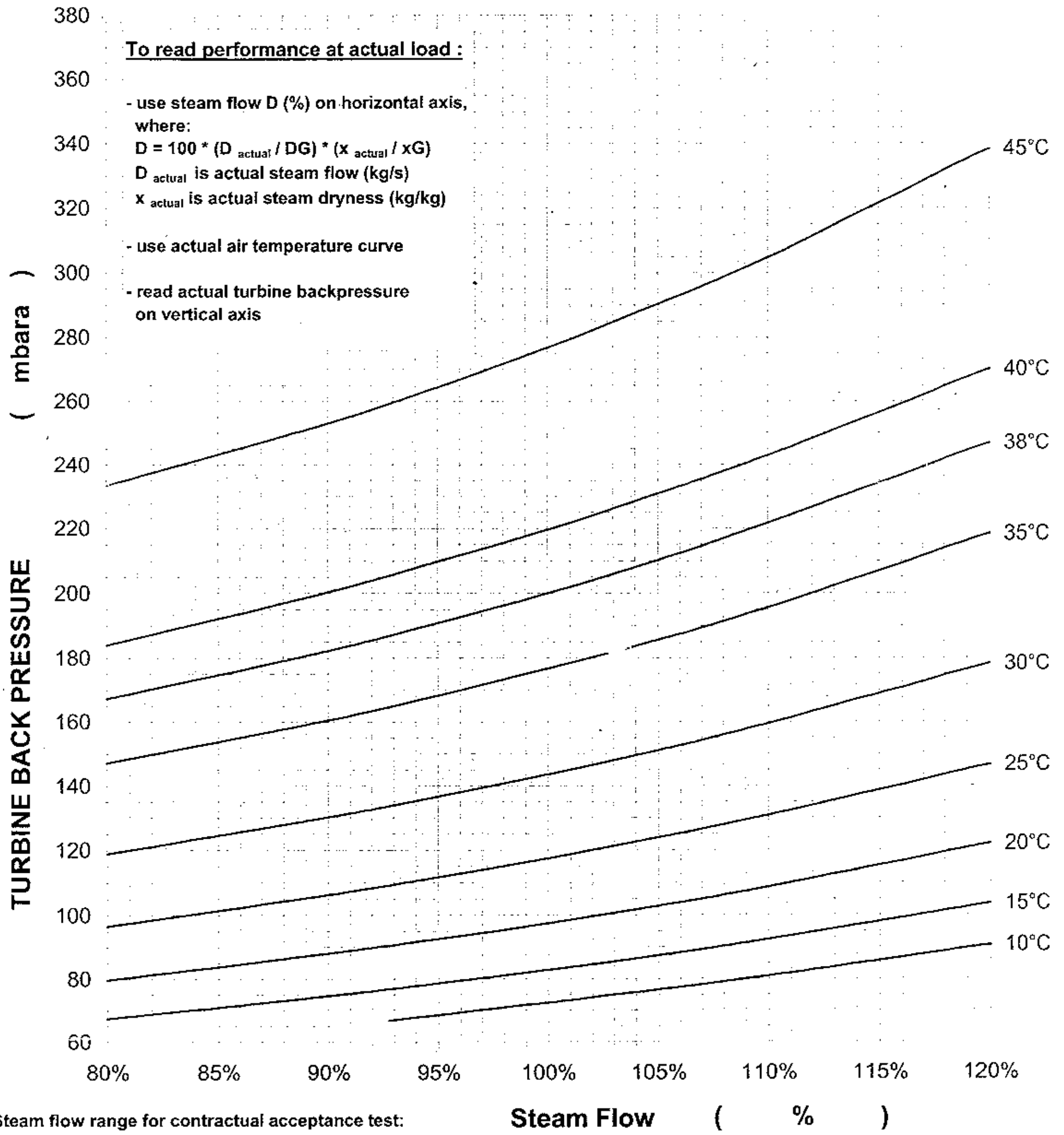
Client	CEA	Document Reference	
Location	Jhajjar (India)		09-101-0162-032_b1_PCUB0001
Document	**PERFORMANCE CURVES FOR CONSTANT DRYNESS**	Proposal Nr	09-101-0162-032_b1

DESIGN CONDITIONS

Steam Flow	DG	298.6	kg/s	Steam Dryness	xG	0.961	kg/kg
Back Pressure	PG	200.	mbara	Barom. Pressure	bG	982.4	mbara
Air Temperature	tLG	38.	°C	Wind Speed (*) (max.)		3.	m/s

(*) 1 m above top manifold level

All Fans at Full Speed **Inlet Air Temperature (°C)**



Steam flow range for contractual acceptance test:

90% - 110% (according to VGB R131 Me 1997)

Revision	-	A	B	C	D	E	F
Date	20-nov-09						
Issued	QVA						
Approved							
Released	MBO						
Status	PRE						

Program N° 37 Perftab3-7 Ver. 3 Rev. 7 - 09 Dec 2008

SPX Cooling Technologies Belgium

SPX
COOLING TECHNOLOGIES

AIR COOLED STEAM CONDENSER (ACC)

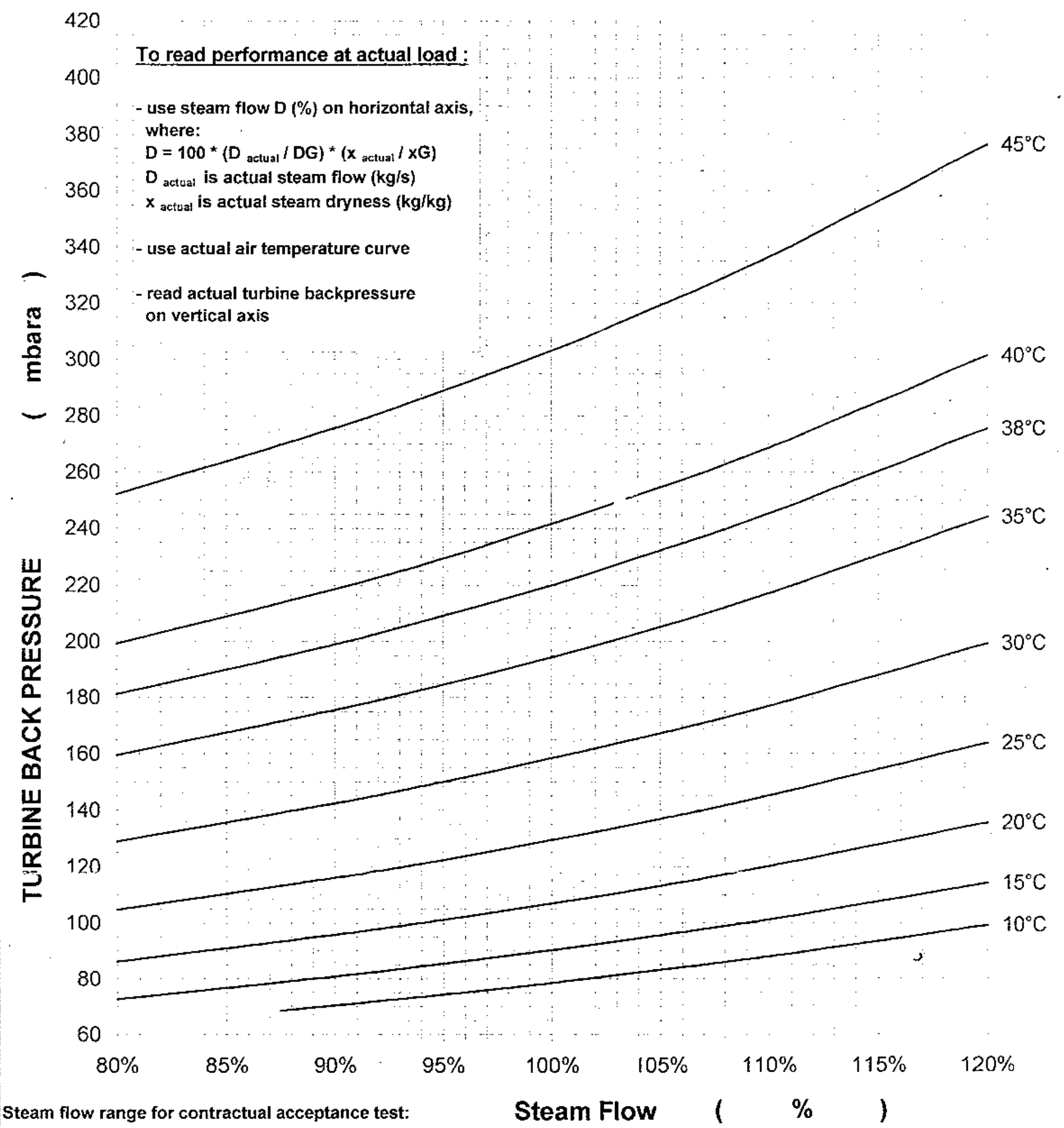
Client	CEA	Document Reference	
Location	Jhajjar (India)		09-101-0162-032_c1_PCUB0001
Document	**PERFORMANCE CURVES FOR CONSTANT DRYNESS**	Proposal Nr	09-101-0162-032_c1

DESIGN CONDITIONS

Steam Flow	DG	299.722 kg/s		Steam Dryness	xG	0.960 kg/kg
Back Pressure	PG	220. mbara		Barom. Pressure	bG	982.4 mbara
Air Temperature	tLG	38. °C		Wind Speed (*) (max.)		3. m/s

(*) 1 m above top manifold level

All Fans at Full Speed **Inlet Air Temperature (°C)**



Steam flow range for contractual acceptance test:
90% - 110% (according to VGB R131 Me 1997)

Revision	-	A	B	C	D	E	F
Date	20-nov-09						
Issued	QVA						
Approved							
Released	MBO						
Status	PRE						

Program N° 37 Perftab3-7 Ver. 3 Rev. 7 - 09 Dec 2008

SPX Cooling Technologies Belgium

SPX COOLING TECHNOLOGIES

AIR COOLED STEAM CONDENSER (ACC)

Client	CEA	Document Reference	09-101-0162-032_d1_PCUB0001
Location	Jhajjar (India)		
Document	**PERFORMANCE CURVES FOR CONSTANT DRYNESS**	Proposal Nr	09-101-0162-032_d1

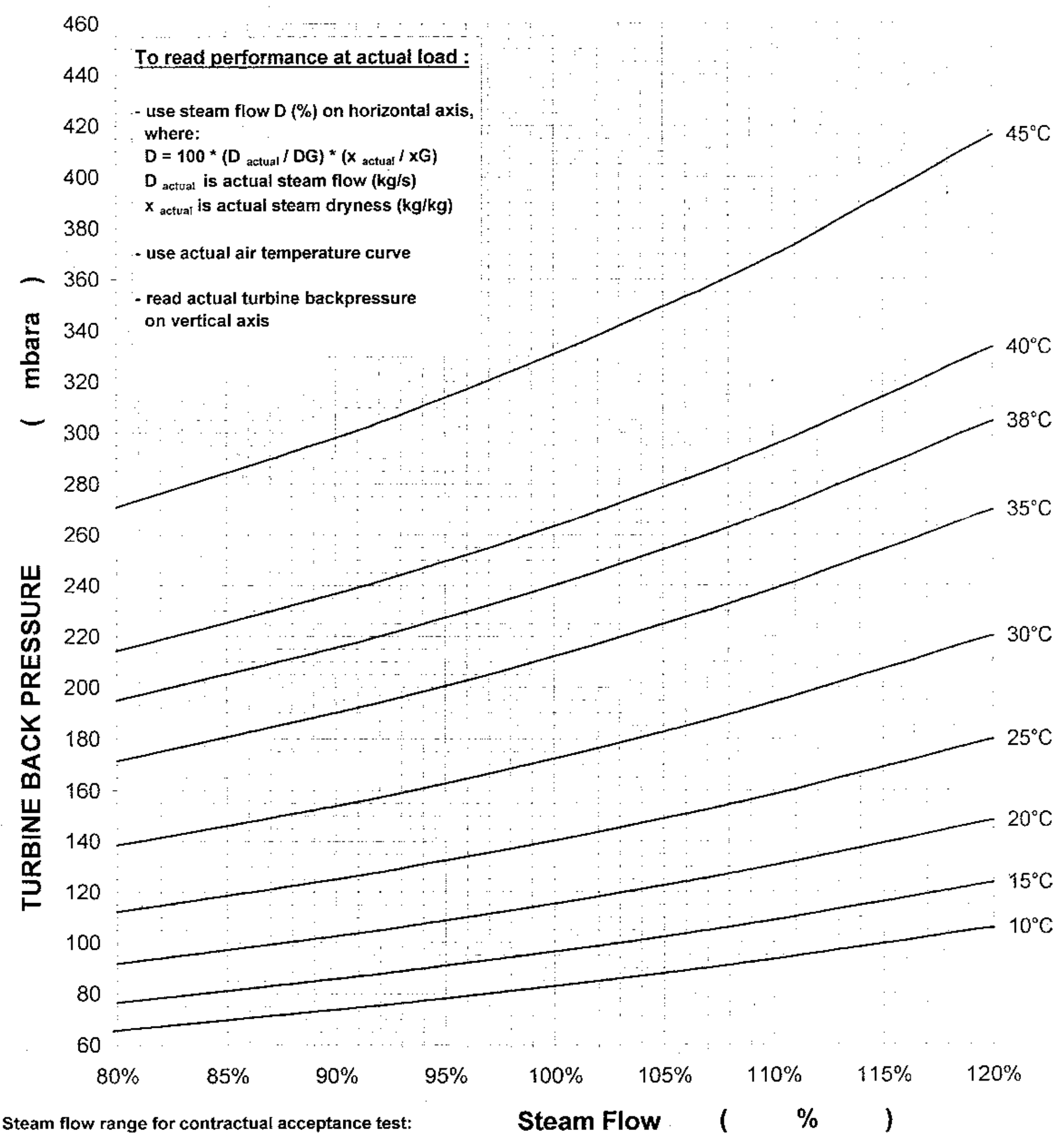
DESIGN CONDITIONS

Steam Flow	DG	300.722 kg/s	Steam Dryness	xG	0.960 kg/kg
Back Pressure	PG	240. mbara	Barom. Pressure	bG	982.4 mbara
Air Temperature	tLG	38. °C	Wind Speed (*) (max.)		3. m/s

(*) 1 m above top manifold level

All Fans at Full Speed

Inlet Air Temperature (°C)



Steam flow range for contractual acceptance test:

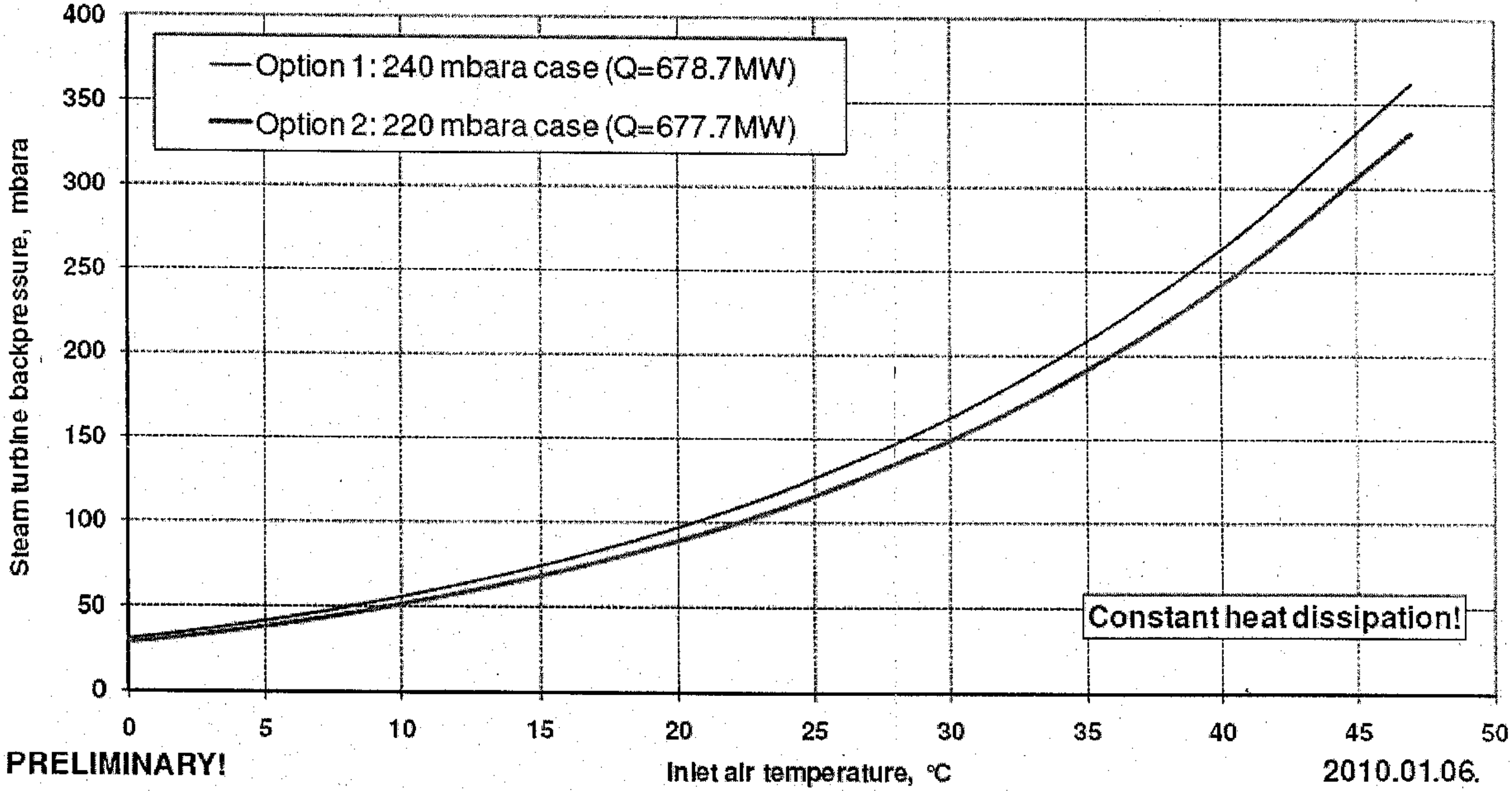
90% - 110% (according to VGB R131 Me 1997)

Revision	-	A	B	C	D	E	F
Date	20-nov-09						
Issued	QVA						
Approved							
Released	MBO						
Status	PRE						

Program N° 37 Perftab3-7 Ver. 3 Rev. 7 - 09 Dec 2008

Appendix – 10

Indirect Dry Cooling HELLER System characteristic curves for 500MW TPP, INDIA



Appendix- 11

Formulation of Techno-economic study for comparison of dry cooling system (direct dry cooling ACC and indirect dry cooling Heller system) with wet cooling system (NDCT/ IDCT).

1	**Project Configuration**		**3x500 MW units**							
2	**Size of BTG plant, MW**		**500 MW**							
			Wet cooling system		**Direct dry cooling system- ACC**				**Indirect dry cooling system- Heller system**	
			NDCT	**IDCT**						
3	**Plant data**									
i)	Design ambinet temperature, ºC		27 (wbt)		38 (dbt)				38 (dbt)	
ii)	Design ITD, ºC		-		19.8	22.1	24.2	26.1	24.17	26.1
iii)	Design condenser pressure, bar(a)		0.1027		0.18	0.2	0.22	0.24	0.22	0.24
iv)	Gross unit output, MW		500		464.4	463.7	462.8	461.9	462.8	461.9
v)	Design heat load of condenser, MWt		-		676.21	676.61	677.39	678.34	677.7	678.7
vi)	ACC provided (No. of cells x motor rating)		-		56x132 kW	48x160 kW	42x200 kW	40x160 kW	-	-
vii)	Bottom dia at HE outskirt in case of Heller system, (m)		-		-	-	-	-	171	155
viii)	Height of NDCT in case of Heller system, (m)		-		-	-	-	-	175	165
ix)	Nos. of cooling deltas in case of Heller system		-		-	-	-	-	210	190
x)	Nominal height of cooling deltas, (m)		-		-	-	-	-	24	24
xi)	TTD value for jet condenser, ºC		-		-	-	-	-	0.6	0.6
xii)	Nos. of jet condensers in case of Heller system		-		-	-	-	-	2	2
4	**Weighted average output**									
i)	Weighted average output factor considering annual variation of ambient dbt		1		1.005	1.005	1.005	1.005	1.005	1.005
ii)	Annual weighted average unit output [3(iv)x4(i)], MW		500		466.722	466.019	465.114	464.210	465.114	464.210
iii)	% shortfall in output		Base		6.66	6.80	6.98	7.16	6.98	7.16
5	**Water & cooling system/ equipment cpapcities**									
i)	Requirement of plant raw water, m^3/h	*	4500		825	825	825	825	825	825
	Water requirement in Ist year, m^3/h	*	5400		1125	1125	1125	1125	1125	1125
ii)	Capacity/ size of raw water reservoir, m3	*	5832000		1215000	1215000	1215000	1215000	1215000	1215000
iii)	Capacity of PT plant, m3/h	*	4500		825	825	825	825	825	825
iv)	Capacity of ETP, m^3/h	*	600		-	-	-	-	-	-
		* For 3 units								
v)	CW flow, m^3/h		55400		-	-	-	-	-	-

vi)	ACW flow, m^3/h		4600		4600	4600	4600	4600	4600	4600
vii)	Capacity of cooling tower, m^3/h		60000		4600	4600	4600	4600	4600	4600
6	**Power consumption**									
i)	Power consumption of ACC, kW		-		6160	6010	6335	5325	-	-
ii)	Power consumption of vacuum pump, kW		150		160	160	160	160	-	-
iii)	Power consumption of COLTCS, kW		20		-	-	-	-	-	-
iv)	Power consumption of CT fans, kW		0	1500	150	150	150	150	150	150
v)	Power consumption of CW pumps/ CW mechanical equipment for Heller system, kW		5217		-	-	-	-	3770	3770
vi)	Power consumption of ACW pumps, kW		178		550	550	550	550	550	550
vii)	Power consumption of raw water intake pumps (80 mwc head, 80% eff.), kW	*	1225.5		224.7	224.7	224.7	224.7	224.7	224.7
viii)	Power consumption of PT plant raw water supply pumps (15 mwc head, 80% eff), kW	*	229.8		42.1	42.1	42.1	42.1	42.1	42.1
ix)	Power consumption of PT plant, kW	*	140		25.7	25.7	25.7	25.7	25.7	25.7
x)	Power consumption of ETP, kW	*	90		0	0	0	0	0	0
		* For 3 units								
xi)	Average power consumption for one unit [i to vi + (vii to x)/3], kW		6126.8	7626.8	7117.5	6967.5	7292.5	6282.5	4567.5	4567.5
	Plant auxiliary power consumption									
xii)	**Differential power consumption for one unit w.r. to wet NDCT, kW**		Base	-	990.7	840.7	1165.7	155.7	-1559.3	-1559.3
a)	Reference aux. power consumption, % of gross output		**6**	-	-	-	-	-	-	-
b)	Auxiliary power consumption of one unit, MW		30	-	30.99	30.84	31.17	30.16	28.44	28.44
c)	Aux. power consumption in case of unit with dry cooling system, % of gross output			-	**6.640**	**6.618**	**6.701**	**6.496**	**6.115**	**6.127**
xiii)	**Differential power consumption for one unit w.r.t. wet IDCT, kW**		-	Base	-509.3	-659.3	-334.3	-1344.3	-3059.3	-3059.3
a)	Reference aux. power consumption, % of gross output		**-**	**6.5**	-	-	-	-	-	-
b)	Auxiliary power consumption of one unit, MW		**-**	32.5	31.99	31.84	32.17	31.16	29.44	29.44
c)	Aux power consumption in case of unit with dry cooling system, % of gross output		**-**		**6.854**	**6.833**	**6.916**	**6.712**	**6.330**	**6.342**
7	**Cost of plant equipment/ systems**									
i)	Indigenous cost component of Heller system, ₹ lakh		-		-	-	-	-	5500	5000

ii)	Imported cost components of Heller system, Euro lakh		-		-	-	-	-	182.6	166
iii)	Equivalent cost in Rs lakh @ Euro 1 = ₹ 63.0		-		-	-	-	-	11503.8	10458
iv)	Cost of ACC, ₹ lakh		-		20000	17500	16000	15000	-	-
v)	Cost of civil works, ₹ lakh		-		3000	2625	2400	2250	12100	11000
vi)	Cost of erection, testing & commissioning, ₹ lakh.		-		2000	1750	1600	1500	3300	3000
vii)	Sub- total for cost of ACC/ Heller system, ₹ lakh		-		**25000**	**21875**	**20000**	**18750**	**32403.8**	**29458**
viii)	Cost of wet cooling surface condenser, ₹ lakh		1500		-	-	-	-	-	-
ix)	Cost of vacuum pumps, ₹Lakh		110		-	-	-	-	-	-
x)	Cost of COLTCS, ₹ lakh		130		-	-	-	-	-	-
xi)	Cost of wet CT, ₹ lakh.	*	21700	12900	1104	1104	1104	1104	1104	1104
xii)	Cost of CW/ACW pumps and EOT crane etc., ₹ lakh (for dry cooling ACW pumps: 1W+1S per unit)	*	1800		396	396	396	396	396	396
xiii)	Cost of raw water pumps & TWS for raw water intake pump house, ₹ Lakh	*	700		199.57	199.57	199.57	199.57	199.57	199.57
xiv)	Cost of raw water supply piping system, ₹ Lakh	*	6080		1733.45	1733.45	1733.45	1733.45	1733.45	1733.45
xv)	Cost of CW treatment system, ₹ lakh	*	100		12.81	12.81	12.81	12.81	12.81	12.81
xvi)	Cost of PT plant, chlorination plant etc. including civil works, ₹ lakh	*	1980		509.63	509.63	509.63	509.63	509.63	509.63
xvii)	Cost of CW chlorination plant including civil works, ₹ lakh	*	120		15.38	15.38	15.38	15.38	15.38	15.38
xviii)	Cost of ETP, ₹ lakh	*	100		0	0	0	0	0	0
xix)	Cost of civil works:									
a)	Cost of raw water reservoir, ₹ lakh	*	8616		1795.00	1795.00	1795.00	1795.00	1795.00	1795.00
b)	Cost of raw water intake system; laying, wrapping, coating, cathodic protection of raw water pipeline (total 18 km length); electrical buildings etc., ₹ lakh	*	4598		1310.92	1310.92	1310.92	1310.92	1310.92	1310.92
c)	Cost of CW/ ACW pump house, forebay & CW channel, CW ducts, ACW piping, electrical buildings etc., ₹ lakh	*	6897		883.78	883.78	883.78	883.78	883.78	883.78
		* For 3 units								
xx)	Differential cost impact of higher back pressure LPT module in dry cooling system, ₹ lakh.		-		1800	1800	1800	1800	1800	1800
xxi)	Total cost for one unit [i to x + (xi to xix)/3 + xx] , ₹ lakh		19304	16370	29454	26329	24454	23204	36857	33912

xxii)	**Differential cost for one unit w.r.t. wet NDCT, ₹ lakh**								
a)	Differential cost for one unit, ₹ lakh.		Base	-	10150	7025	5150	3900	17554	14608
b)	Reference cost of plant installation for conventional uint, ₹ crore/MW of gross output		**5**	-	-	-	-	-	-	-
c)	Capital cost for one unit, ₹ crore		2500		2601.50	2570.25	2551.50	2539.00	2675.54	2646.08
d)	Capital cost for unit with dry cooling system, ₹ crore/MW of gross output				**5.574**	**5.515**	**5.486**	**5.470**	**5.752**	**5.700**
xxiii)	**Differential cost for one unit w.r.t. wet IDCT, ₹ lakh**									
a)	Differential cost for one unit, ₹ lakh.			Base	13083	9958	8083	6833	20487	17541
b)	Reference cost of plant installation for conventional uint, ₹ crore/MW of gross output		-	**5**	-	-	-	-	-	-
c)	Capital cost for one unit, ₹ crore		-	2500	2630.83	2599.58	2580.83	2568.33	2704.87	2675.41
d)	Capital cost for unit with dry cooling system, ₹ crore/MW of gross output				**5.637**	**5.578**	**5.549**	**5.533**	**5.815**	**5.763**
8	**O&M expenses (impact of cost of raw water and chemicals etc.)**									
	Plant load factor		0.85							
i)	Unit cost of raw water , ₹/ m^3		6							
ii)	Cost of raw water, ₹ lakh/year	*	2010.42		368.58	368.58	368.58	368.58	368.58	368.58
iii)	Cost of PT plant chemicals, ₹ lakh/year	*	700		128.33	128.33	128.33	128.33	128.33	128.33
iv)	Cost of CW treatment chemicals, ₹ lakh/year	*	200		15.33	15.33	15.33	15.33	15.33	15.33
v)	Cost of CW & RW chlorine dosing, ₹. lakh/year	*	150		17.50	17.50	17.50	17.50	17.50	17.50
vi)	Cost of ETP chemicals, ₹ lakh/year	*	50		0	0	0	0	0	0
		* For 3 units								
vii)	Total cost of water & chemicals for one unit [(i to vi)/3], ₹ lakh/year		1036.81		176.58	176.58	176.58	176.58	176.58	176.58
viii)	Differential cost of water & chemical for one unit, ₹ lakh/year		Base		-860.23	-860.23	-860.23	-860.23	-860.23	-860.23
ix)	Reference O&M cost, ₹ lakh/year per MW of gross output		**13**		-	-	-	-	-	-
x)	Total amount admissible for O&M of one unit, ₹ lakh/year		6500		5639.77	5639.77	5639.77	5639.77	5639.77	5639.77

xi)	O&M cost for unit with dry cooling system, ₹ lakh/year per MW of gross output		-	**12.08**	**12.10**	**12.13**	**12.15**	**12.13**	**12.15**
9	**Heat rate**								
I)	Gross unit output, MW		500	466.722	466.019	465.114	464.210	465.114	464.210
ii)	Reference gross unit heat rate for wet cooling, kcal/kWh		**2425**						
iii)	Gross unit heat rate for dry cooling, kcal/kWh			**2597.9**	**2601.8**	**2606.9**	**2612.0**	**2606.9**	**2612.0**
iv)	Differential HR rate on gross output basis, kcal/kWh		**Base**	**172.9**	**176.8**	**181.9**	**187.0**	**181.9**	**187.0**
v)	Increased gross heat rate with dry cooling system, %		Base	7.13%	7.29%	7.46%	7.71%	7.46%	7.71%

Appendix-12

Techno-economic study of dry cooling system for condenser cooling in thermal power plants (Typical load centre site- North India) with wet cooling system as NDCT

Sl. No.	Description	Wet Cooling System (NDCT)	Direct Dry Cooling System (ACC)				Indirect Dry Cooling System (Heller system)	
		0.1 ata(a)	**0.18 ata(a)**	**0.20 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**
1	Gross unit output, MW	500	466.72	466.02	465.11	464.21	465.11	464.21
2	Capital cost, ₹ Crore	2500	2601.5	2570.3	2551.5	2539.0	2675.5	2646.1
	₹ Crore/MW	5	5.57	5.52	5.49	5.47	5.75	5.70
3	Auxiliary power consumption, % of gross output	6	6.64	6.62	6.70	6.50	6.12	6.13
4	Gross heat rate, kcal/kWh	2425	2597.9	2601.8	2606.9	2612	2606.9	2612
5	O&M cost, ₹ lakh/MW	13	12.08	12.10	12.13	12.15	12.13	12.15
6	First year tariff							
	- Fixed charges, ₹/kWh	1.63	1.78	1.77	1.76	1.75	1.82	1.81
	- Variable charges, ₹/kWh	1.48	1.59	1.60	1.60	1.60	1.59	1.59
	- Total, ₹/kWh	3.10	3.38	3.36	3.36	3.35	3.41	3.40
	- Differential tariff, ₹/kWh	**Base**	**0.27**	**0.26**	**0.26**	**0.25**	**0.31**	**0.30**
7	Levelised tariff							
	- Fixed charges, ₹/kWh	1.47	1.59	1.58	1.57	1.57	1.62	1.61
	- Variable charges, ₹/kWh	2.50	2.69	2.70	2.70	2.70	2.69	2.69
	- Total, ₹/kWh	3.97	4.28	4.27	4.28	4.27	4.31	4.30
	- Differential tariff, ₹/kWh	**Base**	**0.31**	**0.30**	**0.31**	**0.30**	**0.34**	**0.33**

Appendix- 13

Techno-economic study of dry cooling system for condenser cooling in thermal power plants (Typical load centre site- North India) with wet cooling system as IDCT								
		Wet Cooling System (IDCT)	**Direct Dry Cooling System (ACC)**				**Indirect Direct Dry Cooling System (Heller system)**	
Sl. No.	**Description**	**0.1 ata(a)**	**0.18 ata(a)**	**0.20 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**
1	Gross unit output, MW	500	466.72	466.02	465.11	464.21	465.11	464.21
2	Capital cost, ₹ Crore	2500	2630.8	2599.6	2580.8	2568.3	2704.9	2675.4
	₹ Crore/MW	5	5.64	5.58	5.55	5.53	5.82	5.76
3	Auxiliary power consumption, % of gross output	6.5	6.85	6.83	6.92	6.71	6.33	6.34
4	Gross heat rate, kcal/kWh	2425	2597.9	2601.8	2606.9	2612	2606.9	2612
5	O&M cost, ₹ lakh/MW	13	12.08	12.10	12.13	12.15	12.13	12.15
6	First year tariff							
	- Fixed charges, ₹/kWh	1.63	1.80	1.79	1.78	1.77	1.84	1.83
	- Variable charges, ₹/kWh	1.49	1.60	1.60	1.60	1.60	1.59	1.60
	- Total, ₹/kWh	3.12	3.40	3.39	3.39	3.38	3.44	3.43
	- Differential tariff, ₹/kWh	**Base**	**0.28**	**0.27**	**0.27**	**0.26**	**0.32**	**0.31**
7	Levelised tariff							
	- Fixed charges, ₹/kWh	1.48	1.61	1.60	1.59	1.59	1.64	1.63
	- Variable charges, ₹/kWh	2.51	2.70	2.70	2.71	2.71	2.69	2.70
	- Total, ₹/kWh	3.99	4.31	4.30	4.30	4.29	4.33	4.33
	- Differential tariff, ₹/kWh	**Base**	**0.32**	**0.31**	**0.31**	**0.30**	**0.34**	**0.34**

Appendix- 14

Techno-economic study of dry cooling system for condenser cooling in thermal power plants (Typical pit head site- North India) with wet cooling system as NDCT

Sl. No.	Description	Wet Cooling System (NDCT)	Direct Dry Cooling System (ACC)				Indirect Dry Cooling System (Heller system)	
		0.1 ata(a)	**0.18 ata(a)**	**0.20 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**	**0.22 ata(a)**	**0.24 ata(a)**
1	Gross unit output, MW	500	466.72	466.02	465.11	464.21	465.11	464.21
2	Capital cost, ₹ Crore	2500	2601.5	2570.3	2551.5	2539.0	2675.5	2646.1
	₹ Crore/MW	5	5.57	5.52	5.49	5.47	5.75	5.70
3	Auxiliary power consumption, % of gross output	6	6.64	6.62	6.70	6.50	6.12	6.13
4	Gross heat rate, kcal/kWh	2425	2597.9	2601.8	2606.9	2612	2606.9	2612
5	O&M cost, ₹ lakh/MW	13	12.08	12.10	12.13	12.15	12.13	12.15
6	First year tariff							
	- Fixed charges, ₹/kWh	1.59	1.75	1.73	1.73	1.72	1.79	1.77
	- Variable charges, ₹/kWh	0.71	0.77	0.77	0.77	0.77	0.77	0.77
	- Total, ₹/kWh	2.31	2.52	2.50	2.50	2.49	2.56	2.54
	- Differential tariff, ₹/kWh	**Base**	**0.21**	**0.20**	**0.19**	**0.18**	**0.25**	**0.24**
7	Levelised tariff							
	- Fixed charges, ₹/kWh	1.42	1.53	1.52	1.52	1.51	1.56	1.55
	- Variable charges, ₹/kWh	1.21	1.30	1.30	1.31	1.31	1.30	1.30
	- Total, ₹/kWh	2.63	2.83	2.82	2.82	2.82	2.86	2.85
	- Differential tariff, ₹/kWh	**Base**	**0.21**	**0.20**	**0.20**	**0.19**	**0.23**	**0.23**

Appendix- 15

Techno-economic study of dry cooling system for condenser cooling in thermal power plants (Typical pit head site- North India) with wet cooling system as IDCT								
		Wet Cooling System (IDCT)	**Indirect Dry Cooling System (ACC)**				**Direct Dry Cooling System (Heller system)**	
Sl. No.	**Description**	**0.1 bar(a)**	**0.18 bar(a)**	**0.20 bar(a)**	**0.22 bar(a)**	**0.24 bar(a)**	**0.22 bar(a)**	**0.24 bar(a)**
1	Gross unit output, MW	500	466.72	466.02	465.11	464.21	465.11	464.21
2	Capital cost, ₹ Crore	2500	2630.8	2599.6	2580.8	2568.3	2704.9	2675.4
	₹ Crore/MW	5.00	5.64	5.58	5.55	5.53	5.82	5.76
3	Auxiliary power consumption, % of gross output	6.5	6.85	6.83	6.92	6.71	6.33	6.34
4	Gross heat rate, kcal/kWh	2425	2597.9	2601.8	2606.9	2612	2606.9	2612
5	O&M cost, ₹ lakh/MW	13	12.08	12.10	12.13	12.15	12.13	12.15
6	First year tariff							
	- Fixed charges, ₹/kWh	1.60	1.77	1.75	1.75	1.74	1.81	1.80
	- Variable charges, ₹/kWh	0.72	0.77	0.77	0.78	0.78	0.77	0.77
	- Total, ₹/kWh	2.32	2.54	2.53	2.52	2.51	2.58	2.57
	- Differential tariff, ₹/kWh	**Base**	**0.22**	**0.21**	**0.20**	**0.20**	**0.26**	**0.25**
7	Levelised tariff							
	- Fixed charges, ₹/kWh	1.43	1.55	1.54	1.53	1.53	1.58	1.57
	- Variable charges, ₹/kWh	1.21	1.30	1.31	1.31	1.31	1.30	1.30
	- Total, ₹/kWh	2.64	2.85	2.84	2.84	2.84	2.88	2.87
	- Differential tariff, ₹/kWh	**Base**	**0.21**	**0.20**	**0.20**	**0.20**	**0.24**	**0.23**