Technical Report: Development plan for sustainable flexible operation of thermal power plants

Plan for increased flexibility in Raichur Unit 3 and Ramagundam Unit 7

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Credits

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Executive Summary

In the wake of the findings from the Intergovernmental Panel on Climate Change (IPCC), countries around the world are joining efforts to plan and develop future power systems, where Renewable Energy Sources (RES) will be the paramount players. Denmark is leading the race at European level in the integration of RES in the power system: in 2020, the equivalent of 50% of electricity consumption was produced by variable RES, such as wind and solar. On a different scale, but the same level of ambitions, there is India. By 2040 India is projected to generate two and a half times as much electricity as today, while having ambitious targets to supply substantial amounts of this demand with RES: in 2019 the Indian government announced ambitions to reach 450 GW of installed RES by 2030. In addition, in 2021, during COP26, the Honorable Prime Minister Modi announced even more ambitious targets: 1) 500 GW non-fossil capacity by 2030, 2) 50% energy generation from RE sources, 3) 1 Gt CO2 reduction compared to projections, 4) Carbon intensity reduction of more than 45% and 5) 2070 net-zero target [1]

The recent increase in share of variable renewable energy technologies is challenging the conventional ways to operate the power systems, and the role of the thermal power fleet is becoming more and more important. Due to the fluctuating nature of renewable energy sources, the existing thermal fleet must develop a modus-operandi to adapt their production to the intermittent production from renewables. Faster ramp rates, lower minimum loads and cheaper start-up costs are expected be at the backbone of the flexible operation of the power plants operational practices. The Danish experience shows, in one of the power systems with the largest share of production from variable renewables (50% in 2019), that a proper approach to thermal plant flexibility can facilitate the integration of renewables without compromising the stability of the grid and the operation of the generators.

Long before RE were introduced, most power plants in Denmark were not too flexible (typical ramp rates around 1%/min. and typical minimum load around 50-70%), as they were all functioning as base load plants. Then, thanks to a huge effort taken at political-, transmission system operator-, load dispatch- and plant level, the plants have now reached a level of flexibility which is among the best performing in the world: the ramp rates are on average higher than 4%/min. and the minimum load levels can reach levels as low as 20-25%.

This report focuses on the operational flexibility of thermal power plants, investigating potential opportunities for increased flexibility in Raichur Unit 3 and Ramagundam Unit 7. Based on a technical analysis of the two power plants, the report proposes a benchmark, comparing the selected power plants with the typical conditions in the Danish context and suggesting interventions, based on Danish experiences. The aim is to share detailed information as to how to enhance flexibility for two power plants analyzed and pose the bases for a pilot project investigating flexibility and minimum load capabilities.

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Abbreviations

AFRR	Automatic Frequency Response Reserve
AH	Air Heater
APH	Air Pre-heater
BMCR	Boiler Maximum Continuous Rating
CAPEX	Capital Expenditure
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CIGRE	The International Council on large electric systems
COP	Conference of the Parties
DCS	Distributed Control System
DEA	Danish Energy Agency
DP	Pressure difference
ECO	Economizer
ESP	Electrostatic Precipitator
EU	European Union
FC	Fixed Carbon
FD	Volatile Carbon
FDV	FW valve position
FEGT	Furnace Exit Gas Temperature
FW	Feed Water
GENCO	Generation Company
GHG	Green House Gas
GW	Giga Watt
HBD	Heat Balance Diagrams
HGI	Hardgrove Grindability Index
HHV	High Heating Value
HP	High Pressure
HT	High Temperature

ID	Induced Draft
IEA	International Energy Agency
IEGC	Indian Electricity Grid Code
INDEP	Indian Danish Partnership Programme
IPCC	International Panel on Climate Change
IPP	Independent Power Producer
IR	Infrared
ISGS	Inter State Generating Station
KPCL	Karnataka Power Corporation Limited
KPI	Key Performance Indicator
LDC	Load Dispatch Center
LHV	Lower Heating Value
LP	Low Pressure
MBCR	Maximum Boiler Continuous Rating
MCR	Maximum Continuous Rating
MJ	Mega Joule
MPL	Minimum Power Load
MW	Mega Watt
NOx	Nitrogen-oxide
NPSH	Net Positive Suction Head
NTPC	National Thermal Power Company
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PA	Primary Air
PED	Pressure Equipment Directive
PF	Pulverized Fuel
PI	Proportional Integral
PLF	Power Load Factor
POSOCO	Power System Operation Corporation, now named Grid India

PPA	Power Purchase Agreement
PRAS	Primary Reserve Ancillary Service
RE	Renewable Energy
RES	Renewable Energy Sources
RH	Re-Heater
RLDC	Regional Load Dispatch Center
SA	Secondary Air
SAP	Steam Air Pre-heater
SCR	Selective Catalytic Reduction
SGS	State Generating Stations
SH	Super Heater
SLDC	State Load Dispatch Centre
SP	Set Point
TA	Tertiary Air
TPP	Thermal Power Plant
TPS	Thermal Power Station
TSO	Transmission System Operator
UBC	Un-Burnt Carbon
UV	Ultraviolet
VFD	Variable Frequency Drive
VRE	Variable Renewable Energy

1. Introduction

In the wake of the findings from the Intergovernmental Panel on Climate Change (IPCC), countries around the world are joining efforts to plan and develop future power systems, where Renewable Energy Sources (RES) will be the paramount players. Denmark is leading the race at European level in the integration of RES in the power system: in 2020, the equivalent of 50% of electricity consumption was produced by variable RES, such as wind and solar. On a different scale, but the same level of ambitions, there is India. By 2040 India is projected to generate two and a half times as much electricity as today, while having ambitious targets to supply substantial amounts of this demand with RES: in 2019 the Indian government announced ambitions to reach 500 GW of installed RES by 2030.

The recent increase share of variable renewable energy technologies is challenging the conventional ways to operate the power systems, and the role of the thermal power fleet is becoming more and more important. Due to the fluctuating nature of renewable energy sources, the existing thermal fleet must develop a modus-operandi to adapt their production to the intermittent production from renewables. Faster ramp rates, lower minimum loads and cheaper start-up costs are expected be at the backbone of the flexible operation of the power plants operational practices. The Danish experience shows, in one of the power systems with the largest share of production from variable renewables (50% in 2019), that a proper approach to thermal plant flexibility can facilitate the integration of renewables without compromising the stability of the grid and the operation of the generators.

In Denmark, in other European and international countries such as India, flexibility enhancements of existing thermal power stations – typical coal – have proved to be economically beneficial and a relevant step in the transition from fossil fuel- to renewable-based power systems.

In the 70 ties, long before RE were introduced, most power plants in Denmark were not too flexible (typical ramp rates around 1%/min and typical minimum load around 50-70%), as they were all functioning as base load plants.

Then, thanks to a huge effort taken at political, transmission system operator, load dispatch and plant level, the plants have now reached a level of flexibility which is among the most performing in the world. The ramp rates are on average higher than 4%/min and the minimum load levels can reach as down as 20-25%. In addition, the transformation happened not only because of pushes from higher level (e.g. grid codes imposing minimum load of plants) but also because the plants owners/operators could find an economically attractive business case to have their plant operating in a more flexible way.

The positive outcomes from improving the flexibility potential of thermal plants, e.g. ability to accommodate larger share of fluctuating RES, suggest this could also be the case in India.

The Government of India (GoI) and the Government of Denmark are currently engaged in a government-to-government programme, to jointly address global challenges, green energy transition and climate change. In this framework, India and Denmark launched in 2019 the India-Denmark Energy Partnership (INDEP), a 5-year programme based on government-to-government initiatives between India and Denmark. The objective of the partnership is to create peer-to-peer exchange of knowledge between Danish and Indian experts working with the relevant topics within the renewables sector. The focus is to share experiences in facilitating the development of the electricity sector while integrating a larger share of Renewable Energy (RE).

During 2021 and 2022, the Indian and Danish institutions (DEA, CEA, NTPC and KPCL) have been involved in different knowledge sharing engagements, such as workshops, memos, and targeted meetings to transfer Danish experiences regarding increase of the flexibility of existing Indian thermal power plants. One of the concrete goals of the engagement has been to develop tailored pilot projects on thermal flexibility and low load for two selected plants: Raichur KPCL and Ramagundam NTPC. In this context, Danish experts visited Ramagundam unit 7 in September 2021 and, after receiving technical data, reviewed the plant documentation for both Raichur and Ramagundam. Both plants have the ambitions to lower the minimum boiler load to 40%.

Based on the joint work between Indian and Danish experts, the report illustrates the development plan for the pilot projects for reaching a sustainable flexible operation of thermal power plants, in Raichur Unit 3 and Ramagundam Unit 7. In particular:

- **Chapter 1** provides a contextualization of the work, within the transformation of the energy systems through the green transitions;
- **Chapter 2** illustrates the background in which the thermal power plants operates in India;
- **Chapter 3** elaborates on the Danish experience and learnings in operating thermal power plants at minimum loads, providing case studies to inspire a similar work in India;
- **Chapter 4** explains the criteria adopted and the insights developed for the selection process of the two power plants and units selected for the low load tests;
- **Chapter 5** discusses potential opportunities, possibilities and assumptions for thermal flexibilisation at Raichur and Ramagundam;
- **Chapter 6** illustrates the proposed plan for the execution of pilot projects;
- **Chapter 7** presents the low-load test for the Ramagundam plant – Unit 7;
- **Chapter 8** presents the low-load test for the Raichur plant – Unit 3;
- **Chapter 9** gives a brief account of measures to assess lifetime consumption
- **Chapter 10** summarizes the learnings from the two pilot tests
- **Chapter 11 provides a road-map for reaching low load and ramp rates**

The aim is to share and transfer knowledge about operational flexibility practices at the thermal power fleet level from the Danish experiences to the Indian plant operators. The report provides detailed information as to how to enhance flexibility for two power plants analyzed and poses the basis for a pilot project investigating flexibility and minimum load capabilities. A following phase will also focus on reduction of start-up costs.

2. Background

The aim of this chapter is to provide a description of the context where the Indian power plants operates. Framework conditions, as well as technical insights, can impact the decision making process on the way to operate a power plant. For example, the existence of a power market naturally incentivizes the producers to generate when the price of electricity is high, hence recovering the costs in a shorter time frame through the market. The price signal thus induces larger efforts in making the plant more flexible and take the opportunity to use the “high price” periods.

In Denmark, as well as the rest of Europe, electricity is mostly traded in the electricity markets. As such, the price of electricity from the market is the price at which the generator (e.g. a power plant owner) is remunerated. The electricity price is defined by demand and supply, meaning that based on all the demand and all the generators available in certain price areas, there will be a resulting price. That price (e.g. €/MWh) represents the revenue from the generator (e.g. if the generator produces 100 MWh and the price was 10 €/MWh, the revenues would be 1000 €). This means that Denmark do not have in place particular costs/MWh to provide to the power plants, to account for flexibility. The incentives for the power plants to be flexible are given from the market: if the price is high during a certain hour, the power plant would want to produce during those hours. If the plant is not flexible enough, it will not be able to ramp up/start up and hence would lose the opportunity. Such type of “incentives” were available from the beginning, meaning that it was up to the plant owners to implement flexibility, with no particular measures in place to compensate for the eventual change in plant lifetime.

Figure 1 below provides a graphical representation.

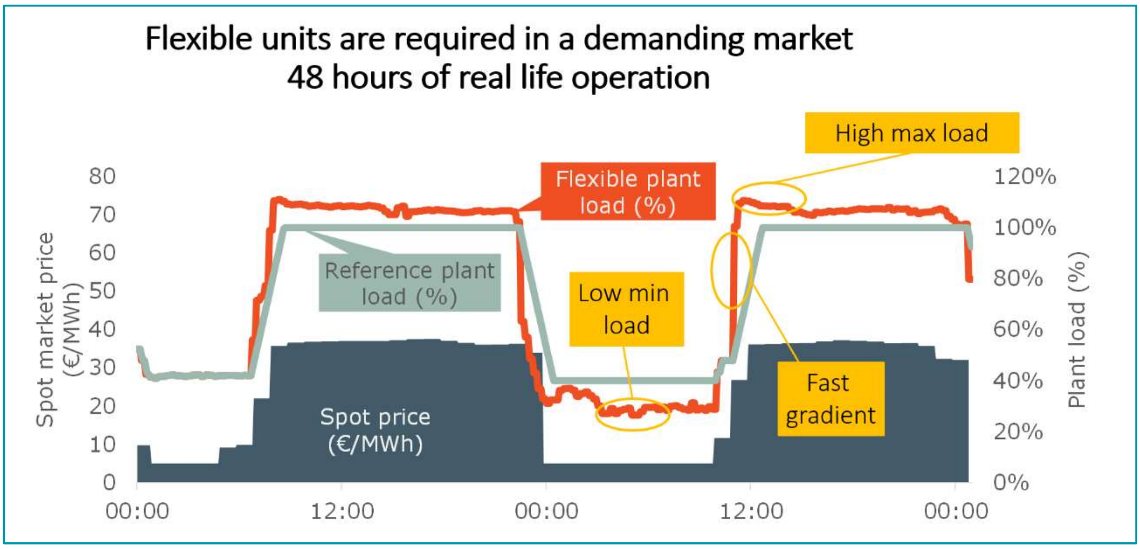


Figure 1 Flexible plant load of a coal fired unit

In the absence of a market, different framework conditions or different production contracts, such as power purchase agreements (PPAs), can impact the sustainable and economic operation of thermal power plants. For instance, stimulating government institutions or plant owners to study the impact of flexibilisation on operating cost of a plant, to develop a proper financial compensation or tariff mechanisms to compensate for the plant life reductions.

As such this chapter elaborates on the framework in India, to facilitate the understanding of the existing challenges for flexibilisation. Later on, towards the end of the pilot projects, this chapter will serve as a benchmark to link technical/financial suggestions based on the results of the study: studying the impact of flexibilisation on operating cost of a plant, as well as eventual financial compensation/ tariff mechanism to account for changes in the reduction of plant life.

Overview of thermal generations of companies

- National Thermal Power Corporation (NTPC)

In India, thermal power plants (TPP) provide almost 78% (131 GW) of total power requirement (180GW) in India, of which about 37% of power is provided by NTPC thermal power plants (considering about 0.85 PLF at 58,500 MW).

The despatching of NTPC generating units lies mainly with the regional load dispatch centres (RLDC). The total number of power plants owned by NTPC stand at 33 coal based, 11 gas based. Its total thermal based (coal and gas) installed capacity is approximately 58,500 MW (which is approximately 35% of 200 GW of installed thermal capacity in India). Moreover, NTPC has also installed 1 Hydro, 1 wind, 12 solar, and 12 other renewable energy based plants, totalling to approximately 5500 MW.

- State Generation (GENCOs)

Each of the state has also established state level Generation companies. Today, of the 375 GW of installed capacity the state generation companies account for almost 28% of capacity i.e. 104 GW [2].

- Private generation Companies

There are multiple private power generation companies in India. Approximately 47% or 178 GW out of 375 GW [2]. Region wise/sector wise/resource wise distribution of installed capacity is shown in Figure 2.

Flexibility Analysis of thermal Generation

Many reports have been made analysing the flexibility of thermal power units in India.

There are 311 coal / lignite power units in operation dating from 1990-2019. The distribution of these is shown in Table 2-1.

Table 2-1 Coal/lignite fueled power units' distribution

Sector	Number	Percent	Power produced
State	**155**	**49.8%**	**32.7%**
Private	**82**	**26.4%**	**36.8%**
Central	**74**	**23.8%.**	**30.5%**

A noteworthy report is the extensive work made by POSOCO [3], reporting a very comprehensive analysis carried out for 438 thermal power units, by studying the min-max load over a 7 year period, from April 2011 - February 2018. The report lists the 438 thermal power units according to the flexibility, but it is not possible to determine which of the power units that are coal/lignite fired. Of the total generated thermal power, 89% is from coal fired power plants. Of these the state sector, private sector and central sector is producing 32.7%, 36.8% and 30.5% respectively.

There is no information on the type of power units in the report, i.e. if the unit is a drum type boiler or once-through boiler.

The vast majority of the thermal power units (428) are operating in an average load above 70% of maximum installed capacity. NTPC (National Thermal Power Corporation) has 24 power plants, with a total of 131 coal fired power units in operation. Of the 438 power units, there are 66, which can operate at or below 55%, and only 3 can operate at or below 40%. It is not clear which of these are coal power plants.

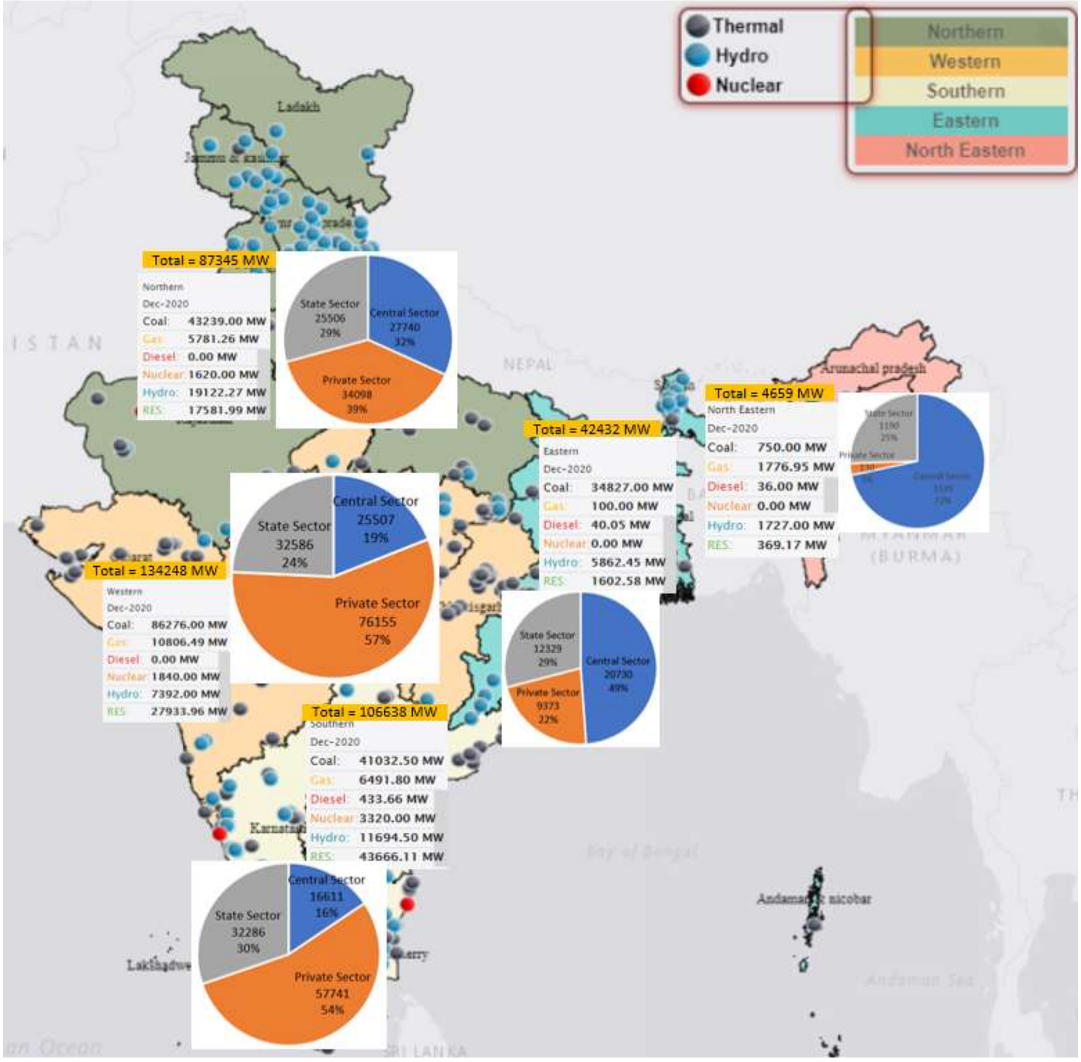


Figure 2 Regional Installed Generation Capacity 2020- Resource wise and Sector wise [15]

Flexibility Toolbox for Power-plants in India

One of the results for achieving increased flexibility, is the possibility of being able to operate the power unit on low load. Recent studies highlight list eight key issues which need to be considered, to achieve increased flexibility for power plant operation. These are all in good correlation with the experience gain in Denmark for achieving high flexibility of power plants.

The 8 key point are listed here:

1. **Raise the awareness for flexibility**

Provide background information about the need for flexibility, explain the necessity and impact on the O&M of the plant, and initiate training programmes.

2. **Identify bottlenecks and limitations with respect to flexible operation:**

- Consult with OEMs to assess the influences of low load operation and temperature and pressure gradients on main components and equipment.
- Ensure smooth operation of all control loops at base load.
- Plan and execute test runs to evaluate the plant flexibility potential
- Create transparency about the plant performance with respect to minimal load, start-up and cycling behaviour in the current setup.
- Identify constraints and process limitations as well as improvement potential.

3. **Optimize the I&C system:**

This is the most cost-effective way to enhance the flexibility of the plant. A certain level of automation is a prerequisite for tapping this potential.

- Smooth control of major power plant processes is a flexibility enabler, e.g. precise steam temperature control.
- Optimizing the underlying control loops, i.e. coal supply, feed water control and air control, is a basic requirement and plant operators need to consider interlocks coming from logics.

4. **Implement mitigation measures**

This is to manage the consequences of flexible / cycling operation. This includes a reassessment of all O&M procedures, with a special focus on water and steam quality, preservation and layup procedures as well as on maintenance strategies. The use of appropriate condition monitoring systems is essential.

5. **Optimize combustion:**

Stable combustion is the key aspect to ensure minimum load operation. The following aspects are very important:

- Reliable flame detection for each individual burner
- Transparency about the coal quality and composition
- Optimized air flow management
- Operation with a reduced number of mills

Adaptation of the boiler protection system to low load operation.

6. **Optimize start-up procedures:**

In order to ensure a fast and consistent start-up, plant operators should check start-up related temperature measurements and consider replacement. Besides automated start-up procedures, this is a prerequisite to assess admissible temperature limitations and to operate with less conservative set points.

7. **<u>Improve the plant efficiency at part load and the dynamic behavior of the plant:</u>**

This refers to measures using the potential of the water-steam cycle – such as frequency support by condensate stop and HP heater optimization – as well as measures enhancing the performance of important equipment and components, e.g. ID, FD and PA fans or feed water pumps.

8. **<u>Improve the coal quality:</u>**

The better the coal quality the better the combustion process. Therefore, measures to improve and to monitor coal quality should be considered, such as blending and washing as well as online coal analysis.

IRENA Flexibility

A key result in the report from IRENA indicates that it will only cost 5-10% more of the total project cost, to install a new power unit that is able to operate at low load, and have the required flexibility to achieve India's National goal to implement more VRE. The report also describes that the lower revenue by operating at low loads, can be exchanged by using the flexibility of the power units, in an intra-day market, by offering fast load change as a supporting product for ensuring a stable grid. To reduce imbalances, however, pricing incentives need to be established.

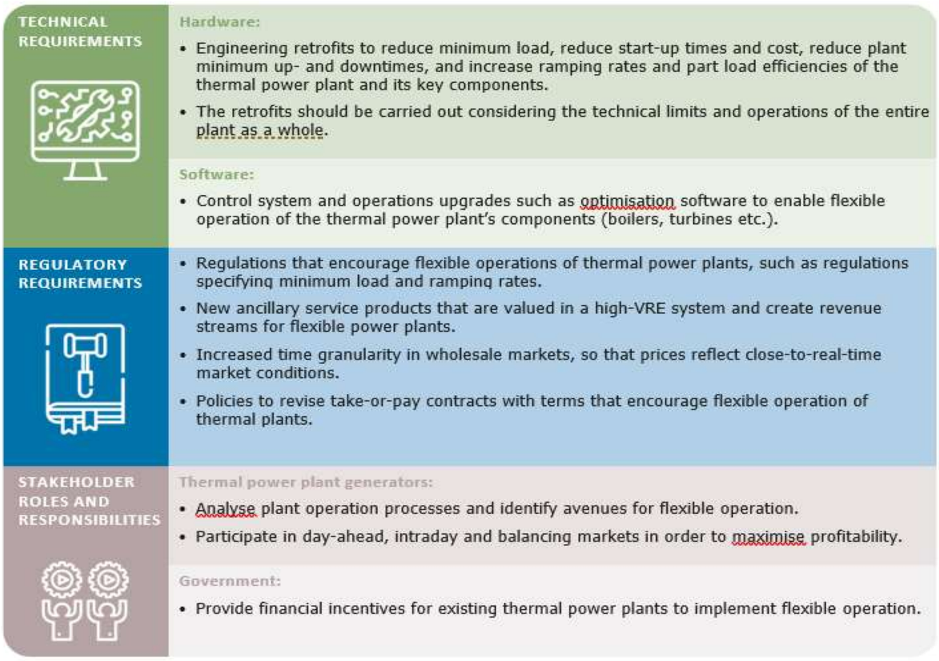


Figure 3 Key results from IRENA

2.1. Framework for thermal flexibility in the Indian context

CEA assesses the differences in RE-penetration levels from state to state as a tool to sustain the secure operation with increasing amount of RE-integration [4]. The requirement of flexible power varies from state to states, according to the share of RE: for example states like Maharashtra, Tamil Nadu, Andhra Pradesh, Gujrat, Karnataka or Rajasthan have huge potentials for renewable energy production and already forecast the need for a large amount of flexible power. On the other hand, states with lower RES capacity do not require the same amount of flexible power. Curtailment of renewable generation can be avoided in RE rich state if their system balancing is done either internally (e.g. with storage of flexible thermal units) or externally, through the support from other states.

Incentives on physical flexibility performance

Thermal power plants must be designed to comply with requirements stipulated according to official regulations; a, b, c, d and g have articles relating to the flexible operation of thermal power plants.

a. *Technical Standards for Connectivity to the Grid*, regulations by the Central Electricity Authority, 2007 as amended time to time;
b. *Indian Electricity Grid Code*, issued by Central Electricity Regulatory Commission (CERC);
c. *Applicable State Grid Code*, issued by appropriate Regulatory Commission;
d. *Technical Standards for Construction of Electrical Plants and Electric Lines*, regulations by the Central Electricity Authority , 2010 as amended time to time;
e. *Measures relating to Safety and Electricity Supply*, regulations by the Central Electricity Authority, 2010 as amended time to time;
f. *Safety Requirements for Construction, Operation and Maintenance of Electrical Plants and Electric Lines*, regulations by the Central Electricity Authority, 2011;
g. *Grid Standards*, regulations by the Central Electricity Authority, 2010.

CEA has, in addition to above regulations, published a draft on regulation of flexible operation of TPP's [5]. The draft lays down a number of requirements for flexibility from thermal power plants feeding into the Indian public grid. In particular, Article 7 specifies how the appropriate load dispatch centers (LDC) shall schedule all coal based power plants, down to minimum power load (MPL) of 55%, to support the operation of must run stations. MPL means the minimum output power the TPP can sustain continuously without oil support, expressed as percentage of nameplate capacity. Must run status means that the generation from such a power plant can only be curtailed due to grid security reasons. RE-generating stations have must-run status in the Indian power system [6]. The draft also includes a provision that allows the appropriate LDC to schedule TPP's to a MPL of 40%, with the purpose of securing must-run status.

Load rate requirement for up and down regulation is 3%/min. When operated above the MPL, for super-critical and ultra-super-critical plants the requirement for load rate is 5%/min. These requirements are already in place from the regulations "*Technical Standard for Construction*

Electrical Plan and Electrical Lines" [7]. Thermal power plants are required to implement necessary modifications, if any, to achieve the requirements.

The Draft IEGC [8], published by CERC and expected to be approved in late 2022, proposes different requirements on some flexibility parameters than the regulation cited in section above. The list below summarizes the articles concerning thermal flexibility:

- *Frequency Control and Reserves – 10 (g):* The generation units shall have their governors or controllers in operation at all times with droop settings of 3-6% or as specified in the CEA technical Standards for Connectivity [8].
- *Frequency Control and Reserves – 10 (h):* All generating stations, including TPP's, shall have the capability of instantaneously picking up to a minimum 105% of their operating level and up to 105% or 110% of their maximum continuous rating (MCR) as the case may be, when the frequency falls suddenly and shall provide primary response [8]
- *Frequency Control and Reserves – 10 (i):* Coal or lignite fired plants shall declare a ramp up or down rate of not less than 1% of ex-bus capacity corresponding to MCR on bar per minute [8].
- *Frequency Control and Reserves 12:* The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of MCR. In addition to this, can the state commissions, fix a different minimum turndown level for a specific regional plant. A TPP can on its own option declare minimum turndown level below 55% of MCR. The TPP shall be compensated for generation below the normative level either per the mechanism in the tariff regulations or in term of the contract between the TPP and the off-takers of the production.

CERC Regulations (*Terms and Conditions of Tariff*) [9] has been in force from April 1st, 2019. The regulation comprises a mechanism to reduce the rate of return of equity for TPP's not being able to ramp their output at 1%/min. or above corresponding to the MCR. In case the TPP is not able to provide ramp rates of 1%/min. the rate of return of equity shall be reduced by 0.25%. The mechanism also includes an incentive for the TPP's to act more flexible: the rate of return of equity can be increased by 0.25% for every additional 1%/min. increase in the ramping performance up to a limit of a total 1% increase in the rate of return of equity.

Incentives from providing ancillary services

Draft IEGC [8] specifies the reserves that the Indian system operators can procure. These are also further explained in an explanatory memorandum on regulations of ancillary services [10].

- **Primary reserves ancillary service (PRAS)**: this reserve response shall start instantly and attain its peak in less than 30 seconds, and shall sustain up to 5 minutes.
- **Secondary Reserve**: is meant to free the capacity engaged by the primary control. This reserve response shall come into service starting from 30 seconds and shall sustain up to 15 minutes.
- **Tertiary reserve**: shall be capable of providing relief for the secondary reserve within 15 minutes of dispatch instructions from RLDC or SLDC and shall be capable of sustaining the service for at least the next 60 minutes.

Naturally must a TPP be able to fulfill these requirements in order to sell un-requisitioned generation on the ancillary service market. In addition to this, there is also the ambition that the procurement of secondary reserves shall seek to reward fast ramping resources; for this, the reserve is planned to be signaled for dispatch based on the ramp rates as well as variable compensation charges [10].

3. The Danish experience on flexibilisation of thermal plants

3.1. The Danish Power Plant Fleet

The Danish power system has a mix of large power stations, decentralized small producers and a large share of renewable energy (mainly wind but also solar). The section gives an overview of the large Danish coal fired Power Plants over 100 MW shown in the figure below with the purpose to let the reader get acquainted with the installed fleet in Denmark.

During the past 20 years several of the existing coal fired units have been lifetime extended and/or converted from coal to wood pellet or straw firing to reduce CO_2 emissions. Only the remaining coal fired units are included in this overview to create a 1-to-1 parallel to the India coal fired plants. The strategy of biomass conversion of coal plants may even be a further area of collaboration since Denmark has a wide experience in this field, e.g. Avedoere Unit 2 in the figure below is a 415 MW_e unit now running solely on wood pellets.

Figure 4 Overview of the large Danish coal fired power plants

All the large power plants in Denmark are placed near large cities and by the sea. The reason for this is that the units all deliver heat to the district heat network of the cities. District heating is the main heating source in the cities and has been developed and expanded over the past 50 years. The units can also run in pure condensing mode using sea water in the condenser if there is no need for the district heat (e.g. in the summertime).

Description of the units

The main data for the large coal fired units are shown in the table below. Regarding ramp rates the units can follow, there is a requirement from the Danish TSO, Energinet, that every large coal fired unit connected to the grid must be able to ramp with 4%/min.

The average ramp rate at different load levels are as below:

Load:	35-50%	Ramp rate: 2%/min
	50-90%	Ramp rate: 4%/min
	90-100%	Ramp rate: 2%/min

Furthermore, each unit must be able to make a load jump when in the load range 50-90% with a size of 5% within 30 seconds where the first 2.5% must be available within 5 seconds.

Table 3-1 Main data for the large Danish coal fired power plants

Plant name	Picture	Main data
Nordjyllands-vaerket unit 3		• Coal fired 850 MW$_{th}$ / 415 MW$_{e}$ / 420 MJ/s$_{heat}$ • Net electric efficiency: 47% • Live steam: 290 bar, 582℃, RH1&2: 580℃, 580℃ • Four Babcock MPS-212 roller mills • Tangential firing and 16 Low Nox burners • Max ramp rate: 16 MW/min (50-90% load) • Min Load: 20 % (one mill and no oil support) • Design coal: Polish 24.68 MJ/kg, Ash range 10-17%
Studstrupvaerket Unit 3 and 4		• Coal/Wood pellet fired 360 MW$_{e}$ / 515 MJ/s$_{heat}$ • Live steam: 250 bar, 540℃, RH1: 49 bar, 540℃ • Four Babcock MPS roller mills • Boxer firing with 24 Mitsui-Babcock Low Nox burners • deNOx catalyst, ESP and wet flue gas desulphurization
Amagervaerket Unit 3 and 4		• Coal/Wood/Straw PF fired 71 MW$_{e}$ / 250 MW$_{heat}$ • Live steam: 185 bar, 562℃, RH1: 74.5 bar, 540℃ • Three vertical Loesche LM 19.2 D roller mills • Front wall fired with 12 low Nox burners – 3 levels • ESP and dry flue gas desulphurization and deNOx cat. • Max ramp rate: 4%/min (50-90% load) • Min load: 30 % (one mill no oil support) • Design coal: Polish 24.68 MJ/kg

Avedoere- vaerket Unit 1		• Coal fired 250 MW_e / 330 MW_{heat} • Live steam: 250 bar, 545℃, RH1: 54 bar, 545℃ • Four Babcock MPS-180 roller mills • Boxer firing with 16 low Nox burners – 4 levels • deNOx catalyst, ESP and wet flue gas desulphurization • Max ramp rate: 12 MW/min (50-90% load) • Min load: 25 %
Fynsvaerket Unit 7		• Coal fired 424 MW_e / 592 MW_{heat} • Live steam: 240 bar, 540℃, RH1: 58 bar, 540℃ • Four Loesche vertical roller mills LM 23.20 D • 16 low NOx burners – 4 levels • Max ramp rate: 16 MW/min (50-90) • Min load: 20% (one mill no oil support) • ECO bypass to enable low load with deNOx catalyst • Design coal: range 23-25.35 MJ/kg – Ash range 10-17%
Esbjergvaerket Unit 3		• Coal fired 380 MW_e / 460 MW_{heat} • Live steam: 250 bar, 560℃, RH1: 54 bar, 560℃ • Three tube mills Stein Industrie BBD 4366 • PF outlet in each end and rotating classifier (Loesche) • 24 tilting low NOx burners – 6 levels • deNOx catalyst, ESP and wet flue gas desulphurization

3.2. General experiences from Danish Power Plants

This chapter proposes a benchmark, comparing the selected power plants with the typical conditions in the Danish context. The aim is to contextualize and suggest an explanation for the proposed interventions as well as provide applied cases of the success of similar interventions in Danish power plants. This is also an opportunity to share knowledge on the Danish modus-operandi of the power plant to inspire the colleagues in India.

The Danish coal fired power plants are all based on super critical once-through boilers while different burner arrangements are applied, i.e. wall-, boxer- as well as tangential-fired.

Fuel Quality

This chapter summarizes the Danish experiences with low load and low-grade coals.

As Denmark has no coal mines, all coal for the Danish plants is imported from all over the world, e.g., from Poland, Colombia, and South Africa. The imported coals are usually high volatile bituminous coals. The Danish experiences are thus based on various types of coal, which could differ from e.g. low-grade coal.

High volatile bituminous coals are common in international coal trade, whereas the lower quality subbituminous coals and especially lignite is used in power stations close to the mines.

According to Design data HHV, the coal used in Raichur and Ramagundam is ranked as low rank lignite coal. Lignite is defined as coals with a calorific value less than 8300 btu/lb or 4611 kcal/kg.

Table 3-2 Coal specifications for Ramagundam, Raichur and typical Danish power plant

Power Plant	Denmark	Ramagundam	Raichur
Coal quality	Typical	Design	Design
Higher Heating Value, kcal/kg	6100	3400	3650
Volatile content	31 %	22 %	21,7 %
Ash content	10 %	42 %	40,9 %
Fixed Carbon	44 %	24 %	29,4 %
Total Moisture	14 %	12 %	8 %
Hardgrove index (HGI)	50	50	45
Fuel ratio (FC / VC)	1.4	1.1	1.35
Coal rank	Medium	Low	Low

The ratio of fixed carbon to volatile matter (fuel ratio) indicates the combustion reactivity and burnout of the coals. A ratio above 1.5 indicates a difficult coal, while a ratio below 1.5 indicates a relatively easy combustible coal. Apparently, Ramagundam coals is a relatively easy combustible coal.

According to Danish experience firing of world-wide import coals in power plant boilers, the Indian coal quality is "in the lower end" of the coal spectra to ensure a reliable ignition, especially at low boiler loads. In Danish power plants, coals with > 20 % volatile matter and max. 10-15 % ash are used. The high ash content in the Indian coals is expected to reduce the ignitability of the coal and thus the ignition velocity.

As an example: for coals with 30% volatile matter, the ignition velocity could be 12.5 m/s with 10% ash content, but only 7.5 m/s, with 35% ash content. The ignition velocity for a given coal type depends also on the composition (heating value) of the volatiles.

Fuel Preparation - Mills

The raw coals are pulverized to dust and dried in coal mills and transported to the burners. The capacity of a mill depends on the coal type (Hardgrove Index, Moisture), and the grinded (pulverized fuel) dust-fineness.

In Denmark different types of mills have been, or are currently used: Ball Ring mills (Babcock 10 E, 8.5 E), Roller mills (MPS 180, 160), Loesche Roller mills and Tube mills (Stein Industrie).

The newer coal mills are supplied with dynamic classifiers for control of the pulverized fuel (p.f.) fineness to the burners (to improve the ignitability and burning out of the flames, especially at low loads).

The p.f. distribution to burners should be within +/- 5% deviation from the average (100%) per burner, which is difficult to obtain in most of the units due to the two-phase flow in the mill / pipe system.

An optimal mill / coal pipe system is experienced to consist of mill with dynamic classifier, one p.f. outlet, riffle-box for fuel distribution and p.f. pipes to burners with the same clean air resistance.

The dynamic classifier, itself, cannot ensure an equal p.f. distribution to more pipe outlets from the mill top.

A non-optimal distribution of fuel dust to burners are often due to coarse p.f. particles from the pulverizer.

Coarse coal particles don't burn as quickly, easily, and cleanly as finer particles. The finer the particles, the better the combustion will be. Retrofitting with dynamic classifiers are one of the primary measures to be taken when aiming for increased flexibility.

Many Danish mills have been modified to optimize the coal grinding, including:

- Central coal pipe elongated for a better control of coal distribution on the coal grinding table.

- Modified throat ring with guiding vanes.
- Installing different deflector/rejector rings to keep recirculation on the grinding table.

These kind of modifications are usually done in a close co-operation with the OEMs and/or other specialists. The mills are usually maintained with an interval of 5000 operating hours and a major overhaul is performed every 25.000 hours.

Fuel Combustion - Burners

In the burners, the coal dust from the mill is mixed with combustion air and ignited.

For a good, stabilized ignition it is essential to keep a steady p.f. flow from pulverizer to burner i.e. without pulsations from the mill or settlements in the pipe system.

It is important to keep a primary air (PA) flow velocity in the burner p.f. pipe outlet adjusted to the actual coal ignition velocity for the coal type to be used. A too low PA velocity can cause flash back or backfire into the burner and a too high velocity will destabilize the flame ignition (long flames, unburnt carbon in fly ash).

In the mill, however, the PA flow into the grinding process should be the same (but without the dried coal moisture) as in the burner p.f. outlet, and will thus influence the lay out of the throat ring in the pulverizer.

Furthermore, the PA flow in the p.f. pipe-system should be sufficiently high to avoid p.f. settlements in horizontal sections or bends – also with low load. Possible erosion problems must be solved in another way. The bends are usually reinforced with high resistant ceramics claddings.

In the burner outlet, the pulverized fuel is mixed with combustion air for the correct air/fuel stoichiometric ratio.

With a high air/fuel-ratio (high air flow/low p.f. flow), the burner will generate a high NOx formation and a good burning out of the char particles.

With a low air/fuel-ratio (low air flow/high p.f. flow), the burner will generate a low NOx formation, but CO and high unburnt carbon in the fly ash.

It is thus important to control fuel as well as the combustion air to each burner.

A swirler device in the burner can improve the mixing of PA and pulverized fuel by twisting and rotating the PA.

In Denmark, the older coal fired units have "radial" burner-swirlers (Babcock), while newer units have axial swirlers (Deutsche Babcock).

The newest Danish coal burners (Burmeister & Wain Energy) have an axial movable ring with fixed vanes. When moving this swirler-ring in a cone, more or less air can by-pass the fixed vanes in the ring and thus control the swirl intensity of the flame.

Controlled swirler setting is important for the ignition stability, especially at low burner-loads, and flame form (to avoid wall impingement).

All Danish coal fired units are designed as dual-fuel units (coal, heavy fuel oil) and the burners are therefore equipped with an oil gun, situated in each burner p.f. pipe. Normally, heavy fuel oil is used during start up only.

Efforts have been made to improve the coal combustion in the Danish power plants:

- Good p.f. fineness from mills – by retrofitting dynamic classifiers
- Good p.f. distribution to the burners, fed from the same mill group
- Individually combustion (secondary air) control to each burner
- Controlled (actuator) swirler setting for each burner
- Controlled operation from over-load to minimum load of the burners belonging to one mill group
- Reliable Flame Scanner signal from each burner in the full load range
- All burners in the same group should be operated the same way

Fuel Combustion - Furnace

In the furnace, the flames should look similar, but with different rotation directions (different swirl directions) and the flames should not hit the walls. Flame impingement will promote CO, slagging and a possible corrosion risk.

The fuel particles should be burning out in the furnace before super-heater platens.

In Denmark the burning of Unburnt Carbon (UBC) must be < 4% carbon in the fly-ash for reuse in the concrete industry.

The temperature field across the furnace outlet should be even and with the same de-super-heater sprays across the boiler – side to side.

The flow field in the furnace is formed by the combinations of swirl directions of the operating burners.

Furnace "side to side imbalance" or "dark" corners can be due to the combination of burner swirl directions.

At low load operation, the burner levels in operation should be selected to ensure the anticipated water/steam process in furnace and super-heaters and to ensure the super-heater/re-heater (SH/RH) steam outlet temperatures.

The technical minimum load of a once-through boiler is limited by the minimum water/steam flow, which can be informed by the supplier.

With low load operation during long time (days), the furnace will cool down slowly, and the furnace CO increase, which will indicate a decreased combustion efficiency. CO monitors and furnace temperature pyrometers will be needed for a safe operation.

With a "not optimized" fuel/air distribution to the burners, sub-stoichiometric flames (or group of flames) can result in long flames with flame-impingement on opposite furnace walls and slagging.

In some Danish power plant boilers, firing specific South African coals, an intensive furnace soot blowing was needed, due to a "fouled" white, reflective ash (with SiO_2, Al_2O_3), coating the furnace walls.

Flame Monitors

To ensure a safe ignition, each burner should be equipped with a flame monitor/scanner mounted onto the burner front plate and with a sight-tube through the burner register so the flame root can be monitored.

In newer installations, a fiber cable with camera in the burner tip, can be used for practical reasons.

Generally, Ultraviolet (UV) monitors are used for fuel oil and Infrared (IR) for coal flames. The actual monitors must be optimized for the actual burner-type (standard/low-NOx) and fuel-type (coal rank/bio).

The burner flame monitors will protect the mill/burner system against incidents (missing fuel supply to mill, primary air or ignition).

For example: with 6 burners per pulverizer at least 4 scanner signals should always be available. With 2 monitors under the decided minimum level of 5 sec., the pulverizer group will be tripped.

The burner flame scanners will also ensure correct flame ignition in the furnace and thus avoid the "black furnace" situation (un-wanted reaction in old p.f. fired units).

Some problems can occur with flame monitors:

- In opposed fired units, the flame scanners, in a burner level out of service, can "see" the flames from the opposite level of burners in service ("ghost flames").

- In units, firing "high ash" coals, fly ash in the combustion air (re-circulated from the regenerative air-heaters) can disturb the sightline in between flame scanner monitor and the flame root and thus disturb the flame signal.
- In addition to the burner flame scanners, optical pyrometers, located in the furnace walls above the burner zone, can be useful to ensure "safe" furnace temperatures during start-up of the boiler or with low load operation (especially during long time operation).
- In Denmark, all coal fired units (retrofitted from heavy fuel oil or new) were equipped with a "LAND" flame scanner for each burner (LAND is the manufacturer). When retrofitting to Low-NOx burners, the flame scanners had to be re-adjusted to monitor the new optimal ignition zone.
- In a newer Coal/Bio-dust fired unit with low-NOx burners, DURAG flame scanners are used (DURAG is the manufacturer).

Low-NOx Combustion

In Denmark, the coal fired boiler plant units were retrofitted with new low-NOx coal burners. A group of power companies developed, together with a local boiler/burner manufacturer (BWE), the next generation low-NOx burners with about 50% NOx reduction. The burners were based on "High Temperature NOx Reduction" with attached flame.

The main goals for the burner development were:

- Separation of the combustion air to the burner into Secondary Air (SA ~15%) and Tertiary Air (TA ~85%) flows (Air staging)
- Both Secondary and Tertiary Air passes were equipped with an axial movable swirl ring. The SA-swirler is in maximum position with coal firing and in minimum position with heavy fuel oil firing (automatic controlled). The tertiary Air swirler is automatically controlled during the load range to give the best "confined" flame shape
- A Flame-holder (Stabilizer Ring) mounted onto the coal pipe outlet to ensure a fast and stabilized (attached) ignition and thus an optimal NOx-reduction
- The "LAND" flame monitors should be re-used during the later burner retrofit.
- A "low to moderate" p.f. outlet velocity improves the flame attachment and thus the flame performance – the outlet velocity should fit to the pulverizer Primary Air inlet (throat ring velocity)
- The burner flames should fit into the furnace being retrofitted (flame impingement on the furnace walls causes slagging, CO and corrosion)
- The attached flame should be resulted in a considerably improved Low-Load performance of the burners and thus of the power plant unit
- The unburnt carbon in fly ash should be minimally affected by the Low-NOx burner retrofit (UBC could increase from 3% to 4% C in the fly ash)

- The furnace exit gas temperature (FEGT) should not be affected by the burner retrofit i.e. same SH and RH attemperator sprays as before retrofit

The power plant units, later retrofitted with the developed low-NOx coal burners described above, fulfilled the expectations in terms of expected performances:

- NOx-reductions up to 50% (depends on burner configuration, burner zone heat release and coal type)
- Considerably improved low load performance of the unit
- Same SH and RH attemperator sprays
- Less slagging (and thus less soot blowing)
- No furnace wall corrosion
- Fly ash still usable by the concrete industry (< 4% C)
- Dependent of the coal type (ignition reactivity). High volatile coals perform with a higher NOx-reduction, than coals with lower volatiles

Summary of Danish Refurbishments

In general the Danish power plants have undergone different refurbishments over the years to improve the flexibility:

- Optimizing the coal mills by:
    - Extended maintenance and replacements
    - Replacing the static with dynamic classifiers
    - Elongated coal pipe
    - Modified throat nozzle ring
    - Deflector/reflector plate rings
- Replacing the burners with low-NOx burners
- Replacing the flame monitor with DURAG make
- Optimizing the control loops

It is expected that similar refurbishments will be beneficial for the enhancement of the flexibility capabilities for the fleet of the Indian Power Plants.

3.3. Examples of control loops at Danish Power Plants

Following the engagement between the Indian and Danish colleagues, and the request to explain each other methods and plants operation, this chapter is included by request of our Indian colleagues to give inspiration for optimization of the control loops.

The examples from the Danish plants are based on the unit "Nordjylland 3". This is an ultra-super critical coal fired unit. It was commissioned in 1998 and at the time was the most efficient coal fired unit in the world, with a net electric efficiency of 47%. It was designed for 30 years of operation.

The unit can both produce power in condensing mode and district heating by extraction of steam before the LP-turbine. The overall data:

- Net electric power at 100% load 380 MW in condensing mode.
- Max. district heating at 100% load 420 MJ/s

The district heating system includes a heat accumulator, allowing flexibility in the heat production and thereby also in the power production.

The steam cycle is a double-reheat cycle, with steam data of:

- Temperatures (Live steam, Hot reheat 1, Hot reheat 2) 582°C/580°C/580°C
- Pressures (Live steam, Hot reheat 1, Hot reheat 2) 290 bar/80 bar/23 bar

The boiler is a once-through tower boiler with 4 tangential fired burner levels and 4 coal mills, one for each level. The coal mills are Babcock MPS-212. The plant is equipped with DeNOx catalyst, electro-static precipitator, and wet flue gas desulphurization.

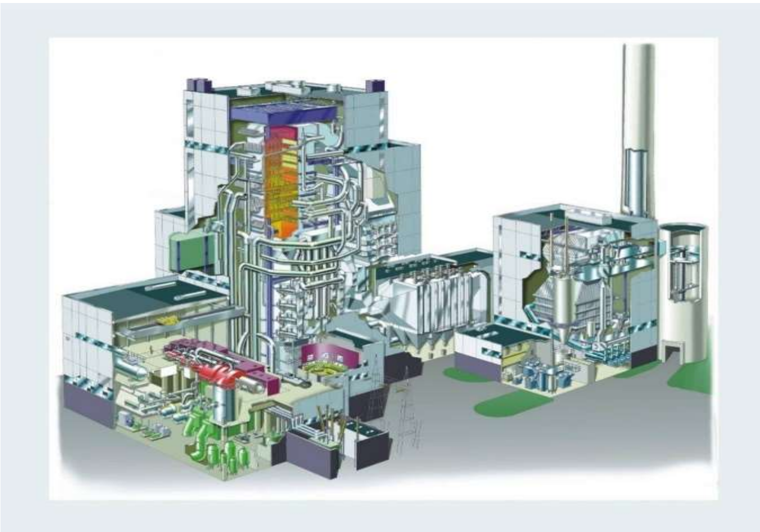


Figure 1 Overview of Nordjylland Unit 3

As the unit was designed with a world record efficiency, at the time of commissioning it was planned to operate primarily at full load all the year. However, the large increase in renewable power over the last two decades has forced the unit to operate in a completely different market, with large variations in electricity prices, and with new requests for minimum load, maximum load, and ramping.

The examples of the control loops from the unit are:

- Overall boiler control and unit control
- Boiler circulation mode control at minimum load.

3.3.1 Boiler and unit control

This chapter provides a brief overview of the unit control and main boiler control loops of Nordjylland Unit 3. Details relating to district heating and overload through HP heater bypass are omitted from the description.

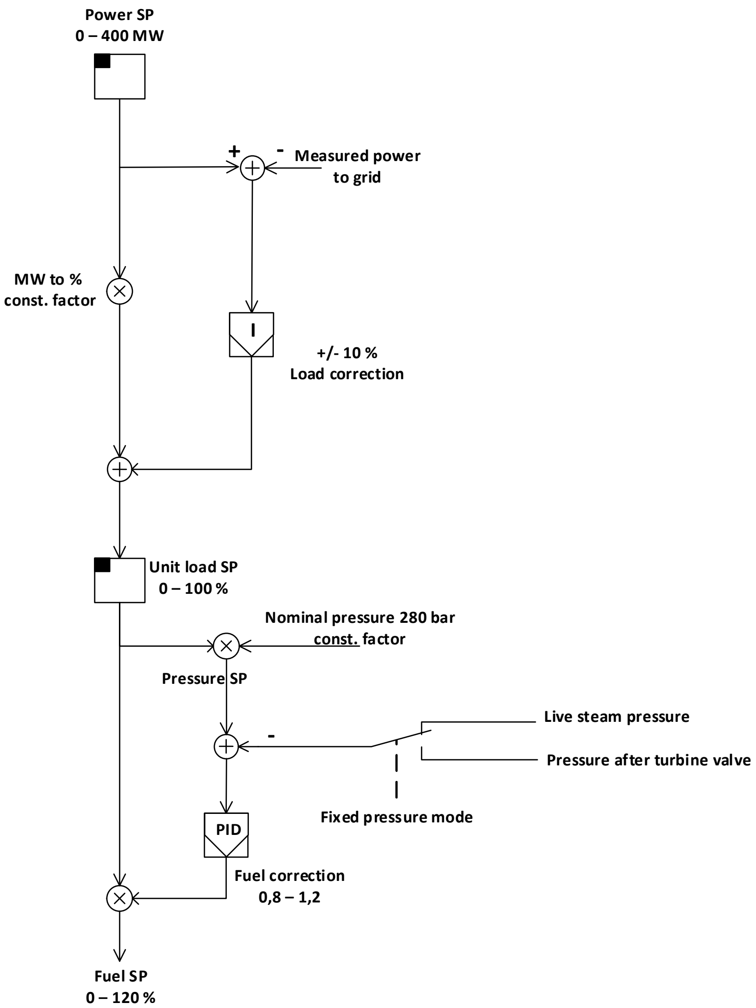


Figure 5 Overview of unit control

The unit is operated in sliding pressure mode for load with pressure higher than 110 bar and fixed pressure mode below 110 bar.

Unit control

The set-point for power output is directly feedforward through the unit controller, where a constant factor scales from the set-point in MW to unit load in percentage. A purely integrating controller serves as load correction, by adding a small contribution to the unit load percentage. The load correction controller is relatively slow and has the job of ensuring that in steady state the unit will match the set-point precisely.

The advantage of using feedforward is that any load changes will pass directly through, and if the unit responds linearly, it will result in a proportional change of the output. However, the speed of the response will correspond to the natural response of the boiler.

Boiler pressure control

The unit load set-point is directly fed forward to the fuel set-point, but the boiler pressure controller puts in a correction signal which is multiplied with the unit load. The output signal is also called the fuel correction, since this will compensate for any change in fuel LHV.

The boiler pressure controller is a slow control loop, since it is tuned with stability as the main objective. But similarly, to the unit control, it is the direct feedforward which should ensure a quick response to any load changes. To get a response that is faster than the natural response of the boiler, the feedforward also has a derivative contribution, meaning that while the load is changing the fuel will be changed more, but this contribution fades away when the load change is over.

The pressure set-point for the boiler at high loads is directly proportional to the unit load set-point. This is because the natural sliding pressure curve for the turbine is proportional to the steam flow.

When the boiler is operating at low load, it is switched to fixed pressure operation and thus the unit cannot operate in sliding pressure below 110 bar. In this mode the turbine valves will control the live steam pressure. In fixed pressure operation the boiler pressure controller is using the pressure after the turbine valves as a measured value. In this way it can still compensate for fuel changes, although the control gain is decreased, so the response becomes quite slow.

Feed water / enthalpy control

The feed water flow is proportional to the unit load, with the enthalpy controller as a correction factor. The enthalpy is measured after the separation vessels. At low loads the feed water must maintain a minimum flow, thus forcing the unit to operate in circulation mode (Figure 6). The minimum flow is increased at the load range of circulation mode operation, to have a larger margin to the trip limit.

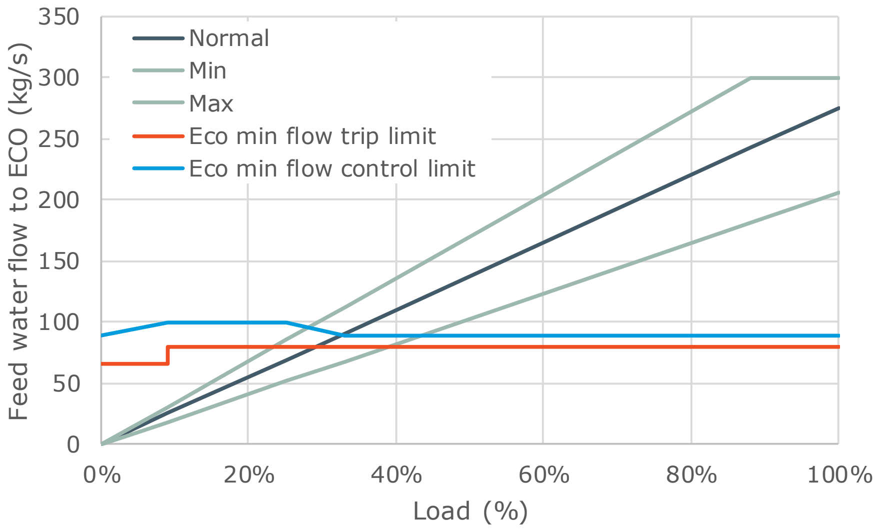


Figure 6 Feed water control limits

The enthalpy set-point is changed dynamically, depending on the load, and with the objective that the attemperators sprays between the super-heaters remain within their control range, in the end this ensures that the live steam temperature is at the set point.

There are several feedforward signals affecting the feed water flow dynamically. Worth mentioning is the so-called decoupling between the boiler pressure control and enthalpy control. Feed water changes and fuel changes will each influence both enthalpy and boiler pressure. Small compensation signals are transferred between the control loops to reduce the disturbance they would otherwise cause to each other.

3.3.2 Trend curves from operation with comments

This section will show trend curves from the operation of Nordjylland unit 3. The intention is to give inspiration to perform similar analyses at Raichur, Ramagundam and similar power plants. This kind of analysis is a very helpful tool for identifying bottlenecks and sub-optimally functioning control loops. As such, this type of analysis would be replicated for both Raichur and Ramagundam, as they will allow to deal with any potential challenge that could impact the plant operation.

The trend shows unit control and overall boiler control, i.e. boiler pressure and enthalpy control.

Trend 1: Load reduction before circulation mode

This trend shows the unit ramping down, first to minimum once-through mode and afterwards a transition to circulation mode. From the graphs in Figure 7, three “markers” (red dotted lines 1-2-3) are relevant to observe:

- **Marker 1:**

  After operating at full load for an extended period the electrical load is reduced. Note that this load reduction happens by changing the district heating production and not the boiler load. The rest of the descriptions will focus on load changes by the boiler.

- **Marker 2:**

  At this point a coal mill is stopped and the unit go from 3 to 2 coal mills in operation. At almost the same time the ramping stops, and the boiler pressure reaches the point of fixed pressure operation at 110 bar. The enthalpy is observed to fluctuate, which is likely due to the change of mill configuration.

- **Marker 3:**

  At the transition to circulation mode, it can be observed that the enthalpy drops rapidly because the feed water flow is not allowed to decrease any further. The consequence is that the enthalpy does not meet the set point during circulation mode. It is not desirable that the enthalpy set-point is too high, since the resulting deviation creates a large disturbance when the boiler returns to once-through mode. Therefore the set point is limited to be only a certain level above the actual enthalpy.

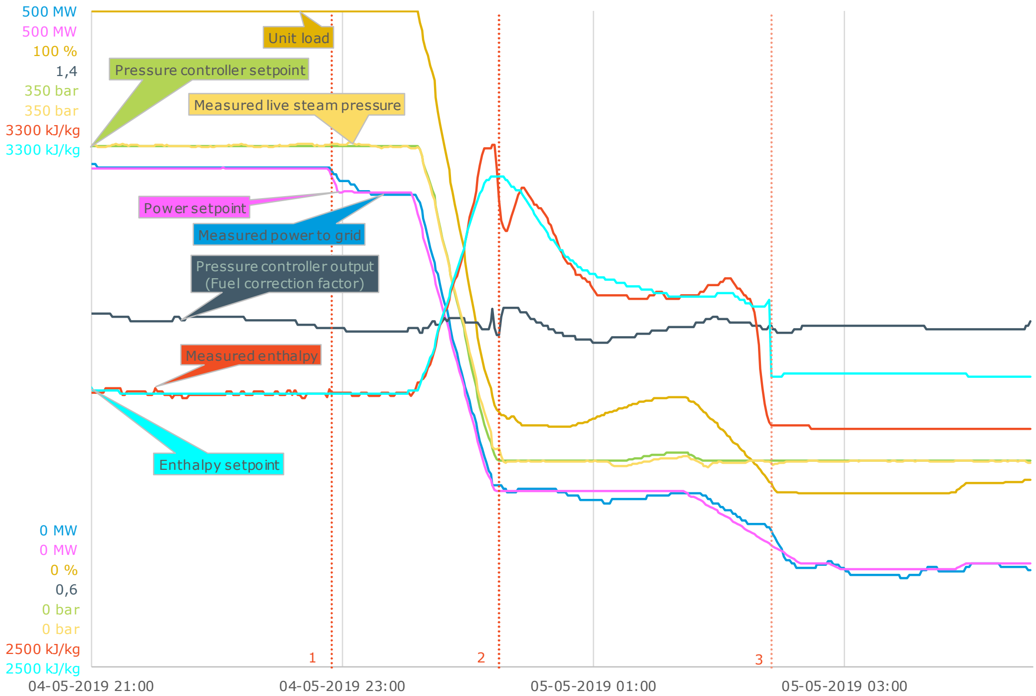


Figure 7 Trend curves for boiler and unit control during ramping to benson minimum and transition to circulation mode

Trend 2: Coal mill started at constant load

This trend shows trend curves for boiler control during coal mill start-up and ramping from 50% to 100% load. From the graphs in Figure 7, two "markers" (red dotted lines 1-2) are relevant to observe:

- **Marker 1:**

  At this point the third coal mill is started. This causes a significant fluctuation of the enthalpy. Shortly after this, the unit load begins ramping up.

- **Marker 2:**

  Approximately 15 minutes after the unit load stops ramping up, there is an overshoot of the boiler pressure. It takes another 15 minutes before the pressure is back at the set-point. At the same time the produced power also overshoots by around 10 MW

  The overshooting of the pressure is quite normal after a large load increase. The main cause is that the pressure controller has a quite slow integral action. In the trend the controller output (fuel correction factor) changes significantly from the start to the end of the curve. In numbers, the correction factor changes from 1.095 to 1.005.

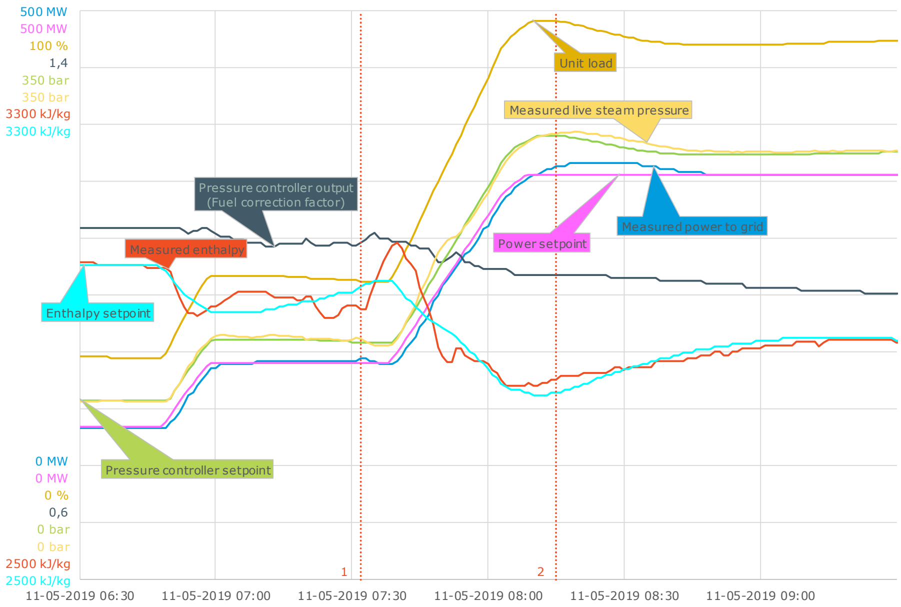


Figure 8 Trend curves for boiler control during coal mill start-up and ramping from 50% to 100% load

Trend 3: Coal mill started during ramp

This trend shows the Boiler and unit control during ramping and coal mill start-up. From the graphs in Figure 8 and Figure 9, three “markers” (red dotted lines 1-2-3) are relevant to observe:

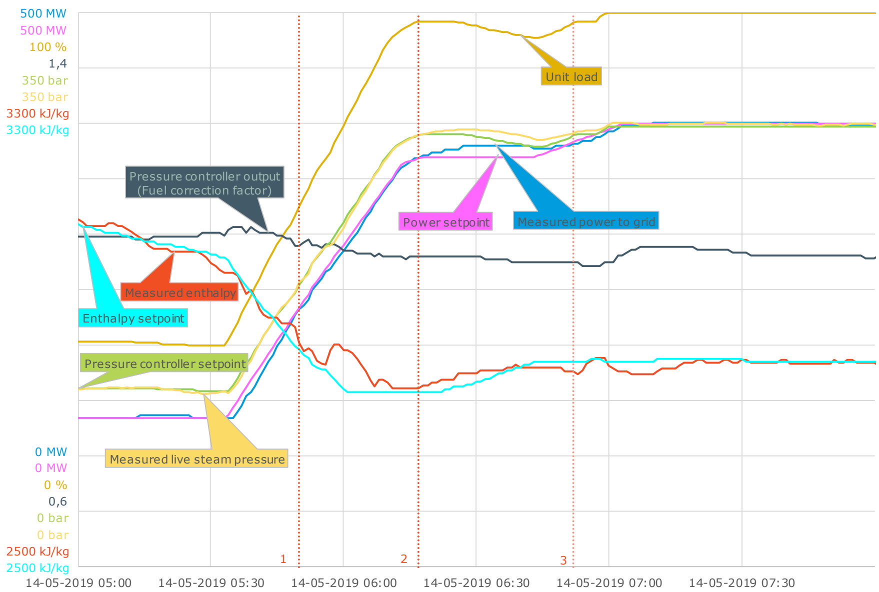


Figure 9 Boiler and unit control during ramping and coal mill start-up

* **Marker 1:**

  At this point the third coal mill is started. There is some fluctuation of the enthalpy after this, but it is quite small. This is not very typical as coal mill start-up during ramping often leads to a significant deviation on the enthalpy control.

* **Marker 2:**

  At this point the load has stopped increasing, and afterwards there is an overshoot of the boiler pressure, like what was seen on trend 2.

* **Marker 3:**

  Shortly before this marker the load increases again. Note that the unit load is paused at 98.5%, this is a precaution put into the unit controller to mitigate the boiler pressure overshoot and avoid overloading the turbine. The load is only allowed to increase to 100% if the boiler pressure has been close to its set-point for some minutes. The same limit comes into effect at marker 2, but currently the load did not need to go to 100% to reach the power set-point.

Trend 4: Secondary control, 100 MW

This trend shows an example of some of the most dynamic operation that this unit is exposed to. The Transmission System Operator (TSO) may order this as a service called Automatic Frequency Restoration Reserve (AFRR). This is used to restore the primary control reserve, which has the direct response to frequency deviations. As an example in the European context, this is used to ensure that the exchanged amount at the German border follows the agreed schedule, which means it must compensate for imbalances in western Denmark.

The TSO sends a continuous set-point for the power change the participating unit should do. In this example 100 MW was sold, which means the load can be changed by this amount in either up or down direction. The gradient requirement is that the change of 100 MW must be delivered in ten minutes, i.e. 10 MW/min. These 100 MW is the absolute maximum amount the Nordjylland Unit 3 can deliver, since it needs to utilize all the load range where a gradient of minimum 10 MW/min can be achieved (Approx. from 46 % to 93% load).

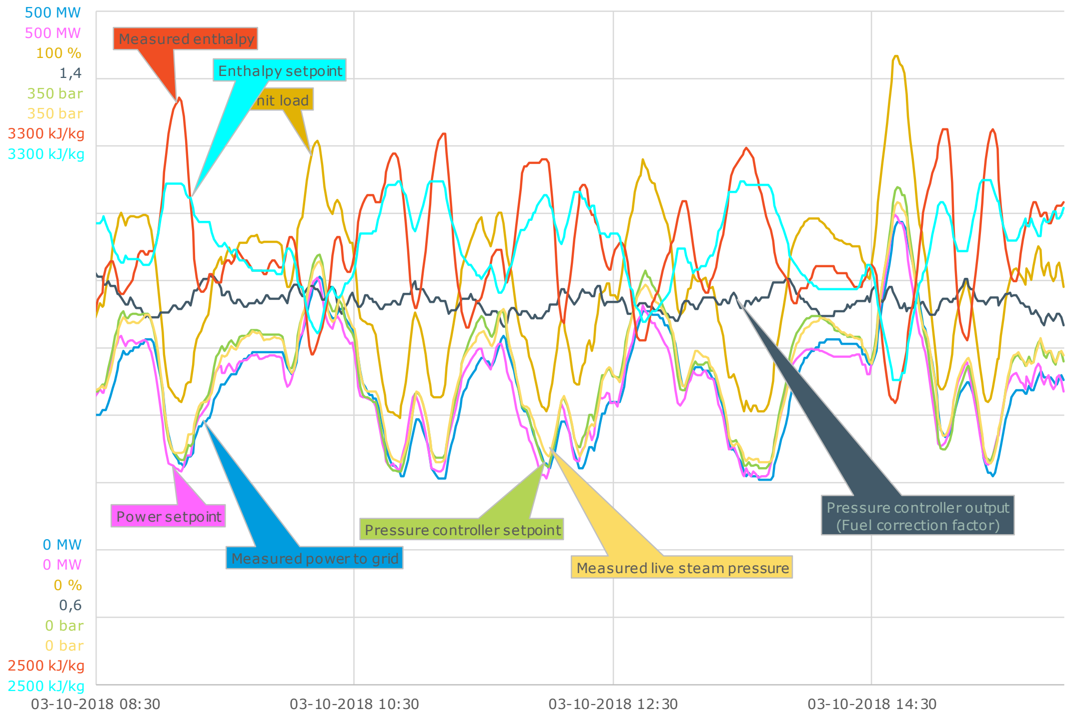


Figure 10 Trend curves for boiler and unit control during delivery of secondary control.

In general, it can be observed that the power output tends to lag somewhat behind the set-point, but this is to be expected since there is some delay in changing the boiler load. The unit is operating in natural sliding pressure mode with turbine valves fully open.

The enthalpy has rather large deviations, which is something that can be provoked by the constant load changes, and especially by doing a steep load increase right after a decrease, or vice versa.

This kind of operation will put additional thermal stresses on the boiler, but on some days, it will be compensated by a significant profit by selling this service.

3.3.3 Once-through boiler circulation mode control

The control logic for the circulation mode control is illustrated in Figure 11.

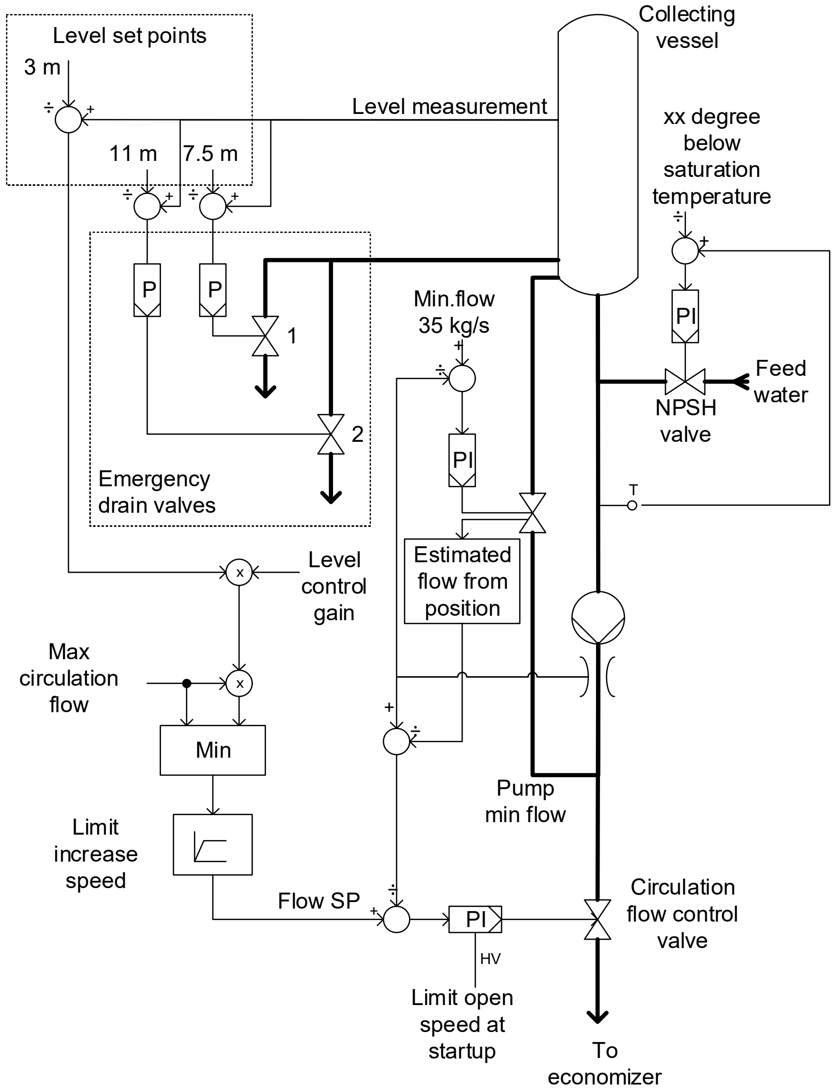


Figure 11 Control logic for circulation mode control

Collecting vessel level control

The most important objective during circulation mode is to maintain a steady level in the collecting vessel. A high level can result in a trip. The collecting vessel is 19 m high with an internal diameter of 450 mm.

- **Circulation flow control valve**

  The circulation flow is controlled with a proportional control loop from the collecting vessel level. Any level above 3 meters will result in a proportionally increasing flow. Note that the flow measurement is right after the circulation pump, and there is a control loop to ensure a min. flow in the pump. The flow through the minimum flow valve is estimated and subtracted to form the measured value for the flow control loop.

- **Emergency drain valves**

  In case the level rises above a certain threshold, the emergency drain valves will begin dumping water from the collecting vessel. This does normally not happen in steady operation in circulation mode but is common during startups. Both valves operate in proportional control, valve 1 will begin opening at a level of 7.5 meters, and valve 2 will begin opening from 11 meters. Both valves will be fully open from a level of around 14 meters, the degree of opening will also depend on the actual pressure.

Feed water flow

The feed water flow through the economizer is controlled to a predefined minimum flow by the feed water pumps. The flow through the economizer is the sum of the circulated flow and the flow from the feed water pumps. Thus, the feed water pumps must constantly compensate for any deviations in the circulated flow (see Figure 11).

Maximum circulation flow

To ensure sub-cooling of the water after the economizer a maximum level is set on the circulation flow. The water in the collecting vessel is at the saturation point, so it is crucial that it is mixed with fresh feed water to ensure sub-cooling. If the water is not sub-cooled after the economizer there is a risk of boiling, which can push large amounts of water to the evaporator since the water expanding to steam takes up a much larger volume. The water can end up in the collecting vessel with a high risk of causing a trip due to high level.

The maximum acceptable flow is calculated based on the temperature in the collection vessel and the feed water temperature.

Minimum flow valve for circulation pump

There is a control valve which will open to let the water flow directly back to the collecting vessel when the circulation flow is low. The valve will open if the flow through the pump is less than 35 kg/s (i.e. 13% load).

NPSH water injection valve

To avoid cavitation in the circulation pump, a small stream of fresh feed water is injected between the collecting vessel and the circulation pump. There is a small control loop with the purpose of achieving a certain amount of sub-cooling before the pump. This valve is mostly modulating in the transitions between circulation and once through mode. When the circulation flow is large, the valve will open fully and the sub-cooling might only be a few degrees. Rather than just operating with the valve fully open, the control loop also ensures that there is no short-cutting of the system between the feed water pumps and the circulation pump.

Warm-keeping control valve

When the boiler is operating in once-through mode, a control valve will let a small flow of water run backwards through the circulation pump to the collecting vessel. The water is bled of after the economizer. The purpose is to maintain a high temperature in the circulation pump, to reduce the temperature gradients it will encounter when entering circulation mode. During circulation mode the valve is closed.

Transition to circulation mode

When preparing for operation in circulation mode, the temperature set-points for the boiler is reduced, and the load will be lowered to around the minimum load required to maintain once-through operation. The boiler will typically be operated at this load for a couple of hours to stabilize temperatures.

To begin the transition, the load is lowered slowly, typically 1 MW/min. When the load drops below 33% the minimum set-point for feed water flow is increased slightly, furthermore 33% is around the point where the steady state feed-water flow should be equal to the minimum set-point. The result of this is that the feed water flow will be higher than what the boiler can evaporate. Thus, the super-heating after the evaporator begins to drop, and after a while the level in the collecting vessel starts to increase.

When the collecting vessel level is above 2.4 meters and the superheating is less than 3 degrees, the circulation pump will be started automatically. At the same time the Net Positive Suction Head (NPSH) valve will begin to open and try to control the temperature before the circulation pump. This also contributes to increasing level in the collecting vessel.

Initially, the minimum flow valve recirculates the full flow from the pump to the collecting vessel. But slowly the circulation control valve will be allowed to open (it follows a ramp until it has opened enough to gain control of the level).

Transition to once-through mode

After operating in circulation mode, the load should be increased slowly, typically 1 MW/min. As the load increases, the flow through the circulation system will decrease. At some point the NPSH valve will begin to throttle to avoid decreasing the temperature before the circulation pump too much. Eventually there will no longer be any flow to the circulation vessel, and the control valve will close to maintain water level. When the steam achieves a superheating of 20 degrees, the circulation pump will be stopped and the NPSH valve will close, if it had not already.

Unit behavior in circulation mode

At low loads the boiler will operate in fixed pressure mode (110 bar from below approx. 40%) At higher loads the unit utilizes natural sliding pressure mode, with turbine valves fully open.

In fixed pressure mode the pressure is controlled by the turbine valves. This can also be named turbine following mode, as the turbine will accept whatever amount of steam the boiler can produce while maintaining a fixed pressure.

The boiler fuel flow is meanwhile controlled to attempt to achieve the desired power output. In practice the power is measured as the steam pressure after the turbine control valves. When operating in circulation mode, the behavior of this control loop is rather slow, and thus it is normal to see some fluctuation of the power output.

Coal mills

During circulation mode, two coal mills are in operation around their minimum limit of 40% of nominal load, corresponding to a unit load of 25%. Normally the two upmost mills will be used, as this ensures the highest flue gas temperature after the furnace, which is critical for keeping the DeNOx plant in operation.

3.3.4 Trend curves from operation

In this section, three different trend curves from actual operation in circulation mode are used to highlight different aspects of circulation mode.

Trend 1: Transition to circulation mode

The unit has been operating at a low load (approx. 40%), with decreased steam temperatures for at least one hour. From the beginning of the trend, the load is slowly decreased. From the graphs in Figure 12, three “markers” (red dotted lines 1-3) are relevant to observe:

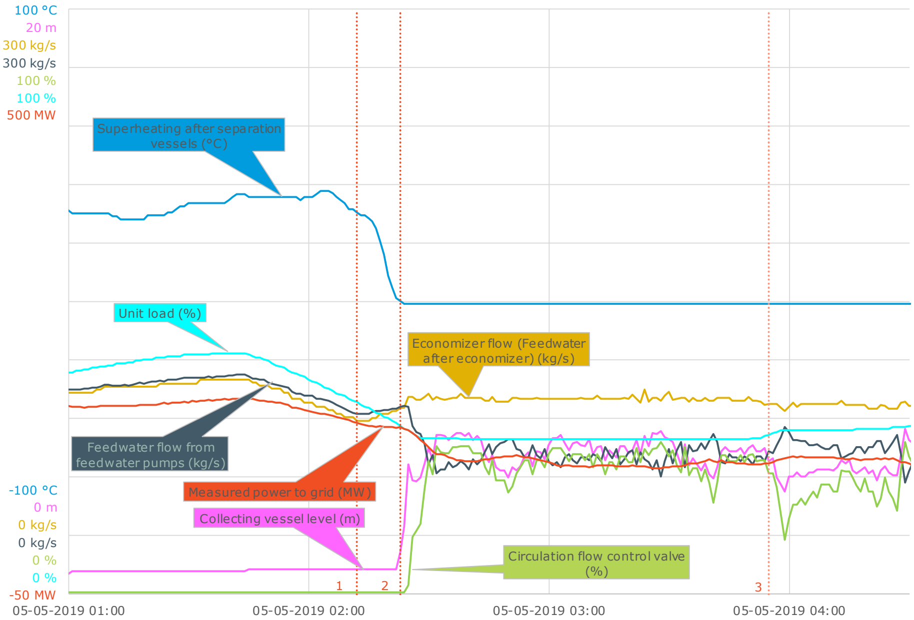


Figure 12 Trend curve for transition from once-through mode into circulation mode

- **Marker 1:**

  At this point the unit load decreases below 33%, and thus it can be seen that the feed-water flow stops decreasing, but instead start to increase even as the load decreases further. The steam after the evaporator has 30 degrees of superheating.

- **Marker 2:**

  At this point the circulation system is started. In the minutes before the level in the collecting vessel has increased and the steam is now at saturation temperature.

  The circulation flow control valve begins to open, until it has control of the collecting vessel level. This causes a flow of circulated water. The economizer flow is controlled to a constant value, although with small fast fluctuations. The flow from the feed water pumps decrease load to compensate for the circulated flow.

- **Marker 3:**

  At this point the load is increased slightly and this causes some fluctuations in the various feed water flows. In steady state a load increase results in a lower circulated flow, and thus a lower collecting vessel level. But the transient changes in level and flows after the load change are somewhat larger.

Trend 2: Several hours of circulation mode

The trend includes the period from trend 1 (Chapter 0), but also the continuous operation in circulation mode after the transition. The unit operates in circulation mode for more than 12 hours and ramp up to once-through mode. From the graphs in Figure 13, three “markers” (red dotted lines 1-3) are relevant to observe:

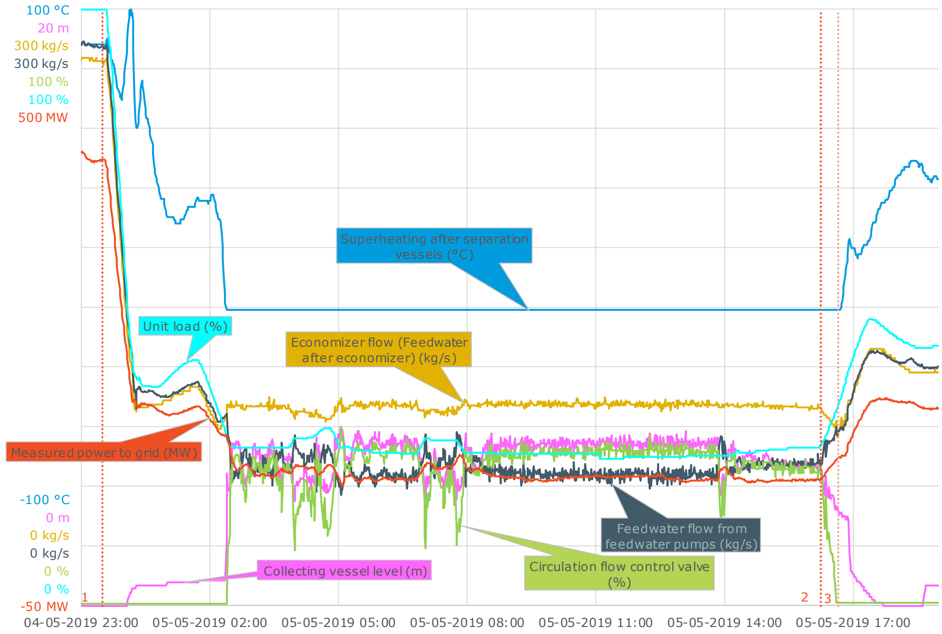


Figure 13 Trend curve for operation in circulation mode

- **<u>Marker 1:</u>**

  Before the transition, the unit was operating at full load and ramped down to around 40% load where the steam temperatures were reduced. The reduction in steam temperature is a necessary preparation before the transition to circulation mode. In circulation mode it is not possible to maintain nominal steam temperatures, and therefore the transition. Near the end of the ramp, a coal mill was taken out of operation.

- **<u>Marker 2:</u>**

  At this point a slow load increase is initiated. Within the next half hour, the circulated flow decreases, and the circulation flow control valve slowly closes. The level in the collecting vessel stabilizes around 3 meters, which is the set-point for the control valve.

- **<u>Marker 3:</u>**

  The load has now increased enough to achieve superheated steam after the separation vessels. 20 degrees of superheating triggers the circulation system to stop operating. Like the transition into circulation mode the economizer flow reaches a minimum at around 33% load, before the enthalpy control begins to increase the feed water flow.

Trend 3: Unit startup

This trend shows the behavior of the circulation system during startup. In this case the emergency drain valves gets to operate for a significant amount of time to control the level in the collecting vessel. From the graphs in Figure 14, four “markers” (red dotted lines 1-2-3-4) are relevant to observe:

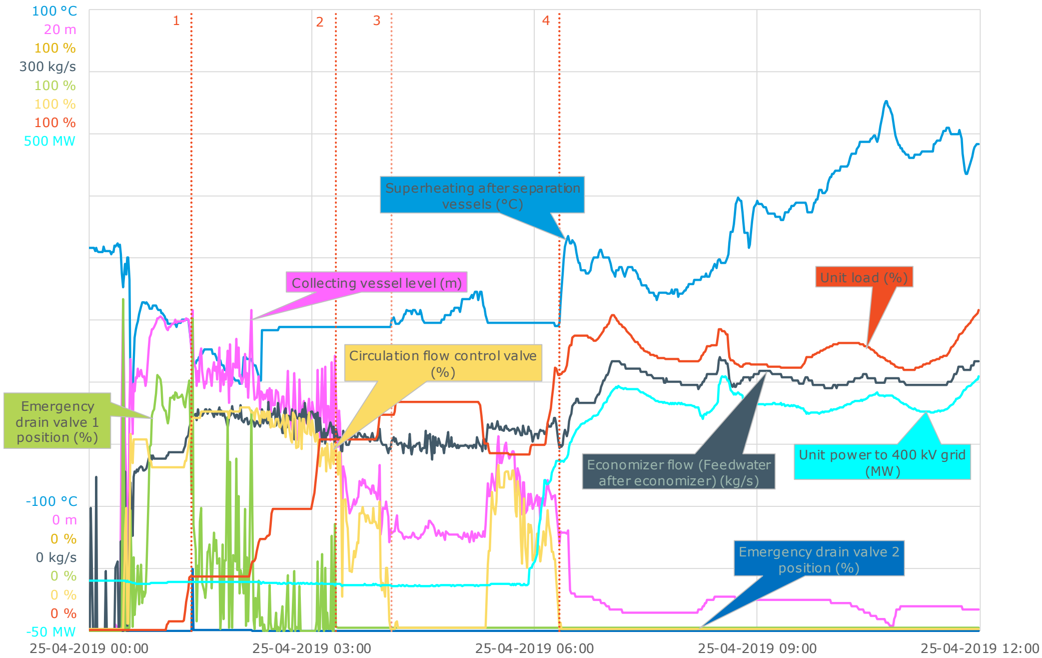


Figure 14 Trend curve for unit start-up

- **<u>Marker 1:</u>**

  At this point there is a short peak in the level of the collecting vessel. It is large enough to cause both emergency drain valves to open, although valve 2 only opens to around 10%.

  The boiler load is set to 10% shortly before the marker and kept at this load for around an hour. During this period the boiler is building up pressure, until a steady flow is achieved in all bypasses.

  It can be observed that the circulation valve never opens more than 37%, while emergency drain valve 1 opens regularly. This is due to the maximum limit on circulation flow, which reduces the risk of boiling in the economizer, which could cause much larger level fluctuations.

- **<u>Marker 2:</u>**

  From this point on, the emergency drains are closed. The load is now increased to around 30%. One main reason that the flow oscillations stop at this point is that the boiler pressure set-point stops ramping up, and thus the bypass valves open significantly more, increasing the steam flow and the flow of fresh feed water.

- **Marker 3:**

  Shortly before this point the load is increased even more. This causes the level in the collecting vessel to drop, and the circulation flow control valve to close. However, the steam temperature never really rises much above the saturation pressure, so the circulation system remains in operation. Later, the load is decreased again, and the circulation flow increases again.

- **Marker 4:**

  At this point the circulation flow has again dropped to zero, and the steam temperatures rise above saturation, because the load was increased significantly. Shortly after this the circulation system stops and the unit continues in once-through mode. Afterwards, the steam temperature rises slowly, most likely to achieve a slow warming of the turbine.

3.3. Danish power plants compliance with regulations on increased flexible operation

The intention of this chapter is to give inspiration on how, in a Danish content, power plant operators deal with existing regulations from the authorities, which e.g. are not aligned with the technical capabilities of the plant. By solid documentation and inclusive dialogue it is often possible to suggest changes to restrictive standard regulations, which could hinder the actual flexible operation of the plant according to technical capabilities.

Case 1: Updated flame trip criteria

This case is from Nordjylland Unit 3.

In the original design it was required to use oil support during mill start-up to ensure flame and safe operation.

Over the years the increased amount of renewable power has significantly changed the operating profile of the unit. Therefore, load variations and mill start/stop are now far more common. It has therefore been desirable to investigate and eventually remove the requirement for oil-support during mill start-up, as this represents a significant saving.

A work group at the plant consisting of operational personnel and plant engineering (combustion and control engineers) was established to investigate further. The work group mainly focused on the case of starting up a mill with clear and safe flame signals both above and below the burner group in question.

The work group had a dialogue with both the boiler manufacturer (BWE) and the coal mill manufacturer (Babcock). Both suppliers agreed that it would be possible to start-up a middle mill without oil-support when there were flame signals both above and below. They also acknowledged that it would not conflict with the standard norm/regulations TRD413 "Pulverized coal firing systems and steam boilers [11]"[1].

However, the suppliers refrained from giving any guarantees on the updated operation procedure. The responsibility was thus accepted by the plant owner, and the plant control engineers implemented the necessary changes in the Distributed Control System (DCS).

The operational staff was instructed that no oil-support was thereafter necessary for start-up of middle burners. The unit has operated with the principle the last approx. 10 years without any problems.

The key learning points from this experience are:

[1] The TRD413 was used for design of the unit, but the regulation has later been replaced by EN12952-9

- The updated operational instructions were still within the scope of the firing system regulation (TRD413).
- The supplier cannot be expected to give guarantee for this type of changes, even if they agree that the changes are technically feasible.

Case 2: Dynamic temperature limits on HP pipes.

The increased demand for flexible operation has led to an increased number of boiler trips due to high temperatures in the boiler tubes and high-pressure pipes.

A root-cause analysis uncovered that most of the trips occurred after a fast load reduction. Even though the firing was reduced quickly during ramping, the steam temperature rose beyond the trip limit owing to the heat stored in the boiler tubes.

As the boiler operate in sliding pressure mode, the steam pressure was significantly below the design pressure when the temperatures were above alarm limit.

This outcome of the root cause analysis promoted an idea to change the temperature limits in part load operation, where the stress on the material is less due to lower steam pressure.

The material specialists made a finite element calculation of all boiler parts, that could be exposed to higher temperature in part load. This confirmed that the materials were able to withstand a higher temperature at part load (lower pressure), and therefore stay within the acceptable limits of the pressure equipment directive of the European commission [12].

According to the pressure equipment directive the proposed changes must be approved by a notified body appointed by the national authority. Based on the engineering work the notified body (the Swedish "*Ångpanna Foreningen*") approved the new limits.

In Figure 15 there is an example of the difference between the old and the new limits. It is obvious that the old limit caused severe limitations on the operation of the plant, while the new limit allows for the actual operation without risking tripping the boiler. It is of course important to recognize that the new limits are fully acceptable by the pressure equipment directive.

The new limits have been implemented at the different plants by the local C&I-engineers, and generally this has significantly decreased the boiler trips due to high temperature limits.

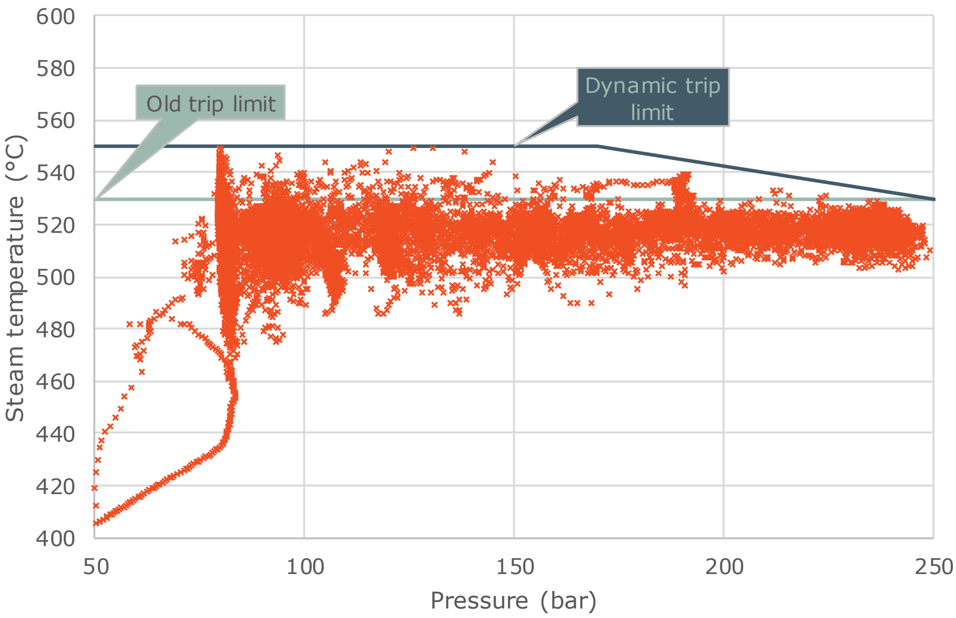


Figure 15 Scatter x-y plot of temperature vs. pressure. The old alarm limit set a lot of limits on the operation of the plant, whereas the new dynamic limit does not interfere with the operation.

Case 3: Minimum load at 20 % without oil support.

The increased demand for flexibility has also increased the demand for lower minimum loads. A low minimum load can often be more desirable when the electricity prices are low as a trade-off with high start and stop cost. In cases with a limited number of hours of low prices, the units are often operated at minimum load and even though they lose money, it is more financially attractive than stopping the unit.

This trade-off between operating at low load and stopping/starting units gives clear incentives to operating at even lower loads and without expensive oil support.

The plant in question is a 400 MW_e unit, with a super-critical once-through boiler (540°C/250 bar). The unit has 4 coal mills. The original design required 2 coal mills with oil support in operation at min. load (30% boiler load).

The boiler minimum load was 20% but this could originally only be achieved with oil firing. For the particular boiler 20% load is the minimum acceptable limit for proper distribution in the water/steam circuit of the boiler.

A test-programme was initiated to uncover if it was possible to reduce the boiler load to 20% without oil support. The test programme did this in an incremental approach:

- Normal minimum load (30%) without oil support
- Step wise reduction of load towards 20%
- 20% load without oil support and only 1 coal mill in operation

Each burner was equipped with individual flame scanners to ensure fire.

The first step was relatively easy achieved but needed adjustment of the primary air flow to ensure even distribution between all burners.

The low reduction towards 20% uncovered that it sometimes was difficult to maintain sufficient flame signals due to very low mill load. It was therefore tested to operate with just one mill. This increased the risk of tripping the unit but at the same time increased the flow of fuel and air in the active mill, which promoted a more stable flame.

After successful testing of the concept, it has been implemented in daily operation. There has been an open-minded dialogue about the increased risk of boiler trip by operating on a single coal mill. However, the plant management has accepted the risk as a reasonable trade-off compared to the increased flexibility of the plant.

Practical experience has proven that only few problems are related to operation with a single coal mill. The operational staff has become comfortable with this mode of operation.

Case 4: Test firing with biomass

Many Danish power plants has been converted to biomass to reduce the CO_2 emissions. Several plants have been converted to 100% biomass firing, recently one of the remaining coal fired units were tested with co-firing of coal and biomass.

The biomass was *steam exploded wood pellets*, with LHV of approx. 19 MJ/kg, low ash (< 0.5%), low water (10%), and high volatile (>30%). The steam exploded pellets can be stored outdoor and does not disintegrate when exposed to water. They can be fired without requirements to modify coal mills or burners. The price is a bit higher than the traditional white pellets, which require indoor storage and modification of mills and burners. The steam exploded pellets are therefore primarily attractive for plants with a limited lifetime, where a low CAPEX for biomass conversion can be accepted at the expense of an increased OPEX.

To test the biomass firing, it was decided to test with one coal mill with wood pellets and two coal mills with coal: one below and one above the "bio mill".

It became clear that the biomass formed a different flame compared to the coal flames. The senior combustion expert was very satisfied when visually inspecting the flames, but at the same time the flame scanners continuously reported low flame signals, just above the trip limit for the mill. After approx. one hour of testing several flame scanners had a drop of signal for more than 5 seconds, which triggered an immediate trip of the mill.

Even though there had been clear visual indication of stable flames it was agreed that the trip logic of the flame scanners could not be altered. This was not even acceptable during a test. Instead it was decided to adjust the aiming point of the flame scanners, in the hope that they would be able to have a clearer detection of the flame.

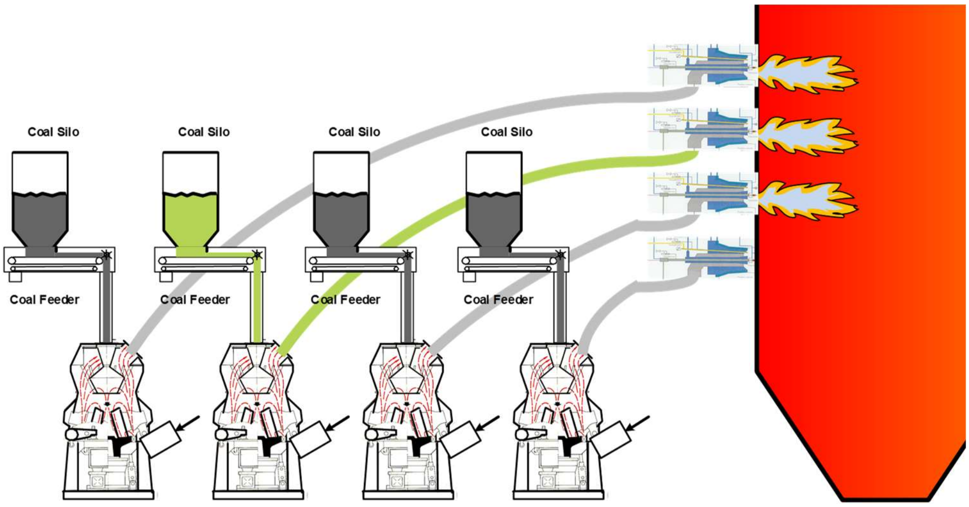


Figure 16 Illustration of bio and coal mill configuration during the test. The green mill is the biomass mill.

After approximately 1 hour of adjustment (see Figure 17), the flame scanner all showed significantly better signals well above the minimum limit, though still lower than the level of the coal burners.

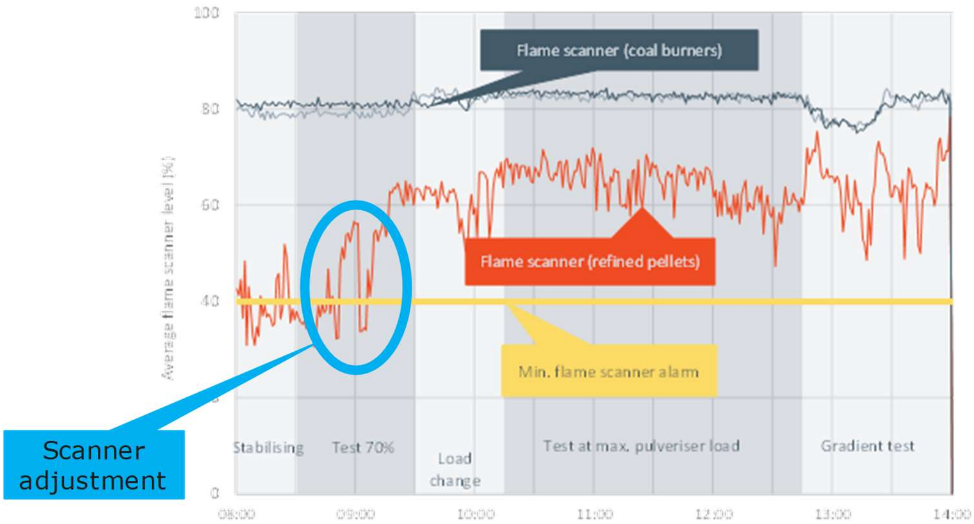


Figure 17 Trend curve for flame scanner signals during the test with co-firing of biomass.

The key learning points regarding increased fuel flexibility can be summarized as follows:

- The test and especially the trip limits for the coal mills were still within the scope of the firing system regulation (TRD413).
- To co-fire biomass the plant owner needs to accept the risk of mechanical breakdown, as the supplier cannot be expected to give any guarantees.

3.4. Experiences from similar international projects

In collaboration with the Danish Energy Agency, the Danish experts from COWI have previous experience on replicating the Danish learnings in an international context. For instance, a study on low load operation of Power Units for coal-based thermal plants was conducted in South Africa. The pilot project allowed to identify technical limitations which currently hinder the development of enhanced flexibility. As a result of this experience, the Danish experts from COWI advised to use a road map, which can be summarized in the following six areas:

Burner improvement

For the purpose of stabilizing the combustion, particularly at low load, it was recommended to install new Low NOx burners. This means installing an air system where SA and TA are individually measured and controlled to each burner. SA and TA also have individual swirler systems and the burners will be able to start/stop completely without manual interaction. Also, it was suggested to add flame scanners for each burner.

Mill improvement

In close cooperation with a supplier, it was suggested to develop a specific upgrade programme for the mills to expand the load range of the mills. This will also include completely automatic start/stop of mills without any manual interaction. The mill load range must ensure a full flexible operation and should incorporate a frequency-controlled classifier, with the purpose to gain a better pulverized fuel fineness.

Coal Quality improvement

Indian coal has the highest amount of ash content, ranging between 25-50%. This means that a high fuel flow must be utilized in order to ensure safe combustion which is restricting how low a load that can be obtained. One of the results from the South Africa test, was the problem regarding low load and flexibility because of poor coal quality, which resulted in poor combustion. The coal arriving directly from the mines into the day silos was not mixed. It was suggested to be able to feed “other” coal types into the day silos of the low load mills, i.e. rebuilding the feeding system and enabling a coal storage system on site. This way it became possible to use external coal, mix coal and also store coal for later use when the quality from the mines was good.

Gradient & Control improvement

Another key suggestion was to optimize and tune the control loops of the boilers (pressure control, fuel control, mill control, feed water, circulation systems, steam temperature, air control, ..), when gradually running with larger gradients (up to at least 4%/min) and lower load levels, until they behaved acceptable even at large gradients.

Automated fleet wise load distribution.

In close cooperation with the Danish TSO Energinet, it was suggested to develop an upgraded programme for the automated fleet wise load distribution system already in place. The aim was to optimize both the economy, a technically faster and better response to the grid and TSO demands. These considerations allowed the operators of the thermal fleet to be better prepared for the future competition from new generators producing and delivering power to the grid on free market conditions. This includes intense use of regulating power delivered by activating fast control handles at the individual stations, as well as a centrally controlled primary grid support system.

Start-up time improvement.

This is an exercise of identifying the bottlenecks regarding start up time and improve or eliminate them one by one. This will save a lot on the oil budget and also enable plant operators to stop and start units faster, i.e. meet the requirement for lower load at night much better.

These six routes should be backed up by a strong effort in parallel to share knowledge with the power plants engineers and thermal power plant operators, aiming at increasing skills and give confidence in operating thermal power plants in a more flexible way.

A road map similar to the one presented could be replicated in an Indian context and, potentially, it will lead to highly useful learnings for assessing the role of thermal plant flexibility in future power systems.

3.5. Learnings from Danish experience with thermal plant flexibility

The purpose of this chapter is to provide the reader with an understanding of the mechanisms that facilitated, throughout the years, the increased flexibility in the Danish power generation system. It also gives an overview of the technical challenges that had to be solved along the way to achieve high levels of flexibility within the thermal power plants.

Four steps towards flexibility

Increasing flexibility of the power generation system in Denmark is the result of a long-lasting collaboration between four levels of institutions as illustrated in the Figure 18 below.

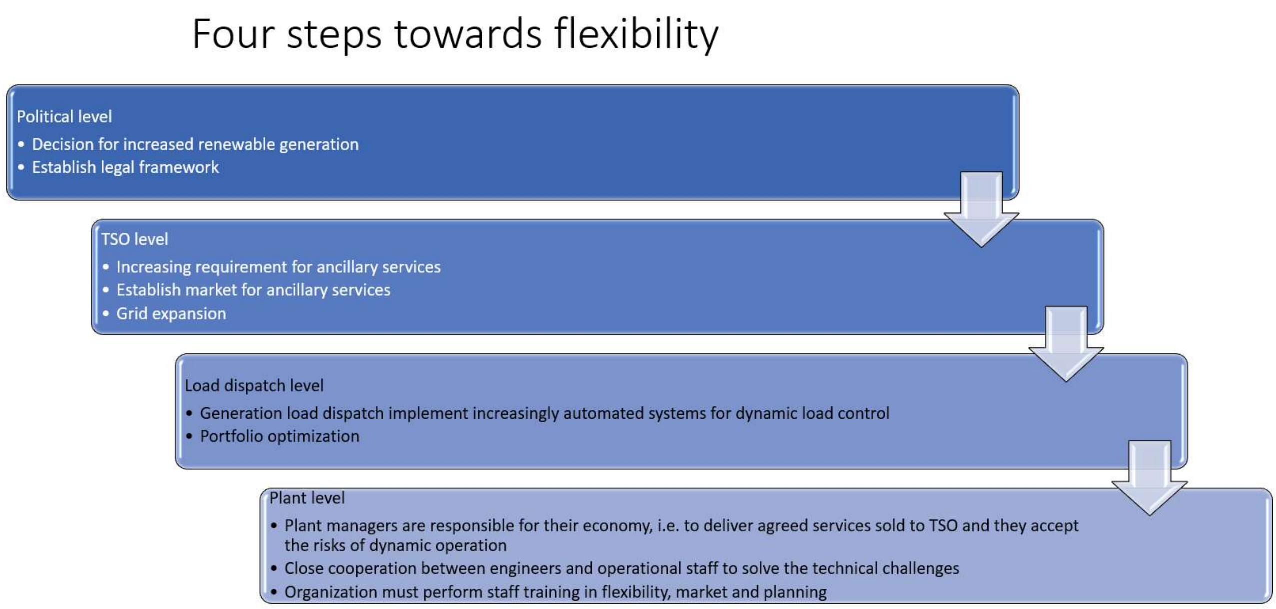


Figure 18 Four steps towards flexibility

1. **Political level:** First, there must be an active political decision to have an increased share of Renewable Energy in the energy system. The Danish experience showed that a large Governmental agreement on RE targets, and the consequent establishment of the legal framework and eventual incentives, helped to speed up the introduction of Renewable Energy. In Denmark incentive programmes helped the development of windmill parks in the early years when technology was still not mature and expensive, but in the recent years it turns out that wind-turbine parks can be run on free market conditions without incentives and still have a good business case. The legal framework covered establishment of the wholesale market and the conditions between Transmission System Operators (TSO) and the Power plants (the last part was initiated through EU laws with the 3-layer model: Generation, Transmission and Distribution).

2. **TSO level**: The second level is the TSO, which is responsible for establishing the wholesale market including the market for ancillary services (frequency support, regulating active power etc.). In practice a power exchange was established, and this is where the day ahead schedules are settled every day.
   The TSO is also responsible for the grid expansion in the country and this is a very large task since the production of Renewable Energy is generally located far away from the main consumption of power. Also, as the Renewable production does not necessarily

match the consumption timing either, the grid connections to neighbouring countries also needed a severe upgrade.

3. **Load dispatch level:** The third level is the load dispatch capability, which had to be substantially automated for automatic distribution of load commands to the connected power station units with updated set points every 5 minutes. The load dispatch is based on optimization of economic parameters and weather forecasts as well as online calculation of the actual flexibility for all units. All the parameters are then fed back into the dispatch algorithm.

   Set points for load to each unit is even expanded with automatic set points for frequency support services and regulating power services.

4. **Plant level:** The fourth level is the plant level. It is important that plant managers are able to act freely within their economic frame, to be able to implement the needed technical solutions and also to accept the increased risks of running more dynamic with the units. For instance, if plant managers are measured on KPI's about how many trips they have while operating the plant, this will slow down every process towards flexibility. As such, it should be avoided.

   At the plants organizational level it is important that staff is trained in understanding flexibility, market awareness and planning issues because without the proper education of the maintenance and operational staff the full potential of the units flexibility cannot be utilized. Finally, it is important that plant engineers and experienced control room staff are given the possibilities to design and implement technical solutions that increase flexibility.

Method for increasing flexibility

As the previous section demonstrated, increasing flexibility is about a lot more than just looking at technical problems. This section is focusing on the method used to systematically increase flexibility at the Danish power plants at the technical level. The method is illustrated in the figure below.

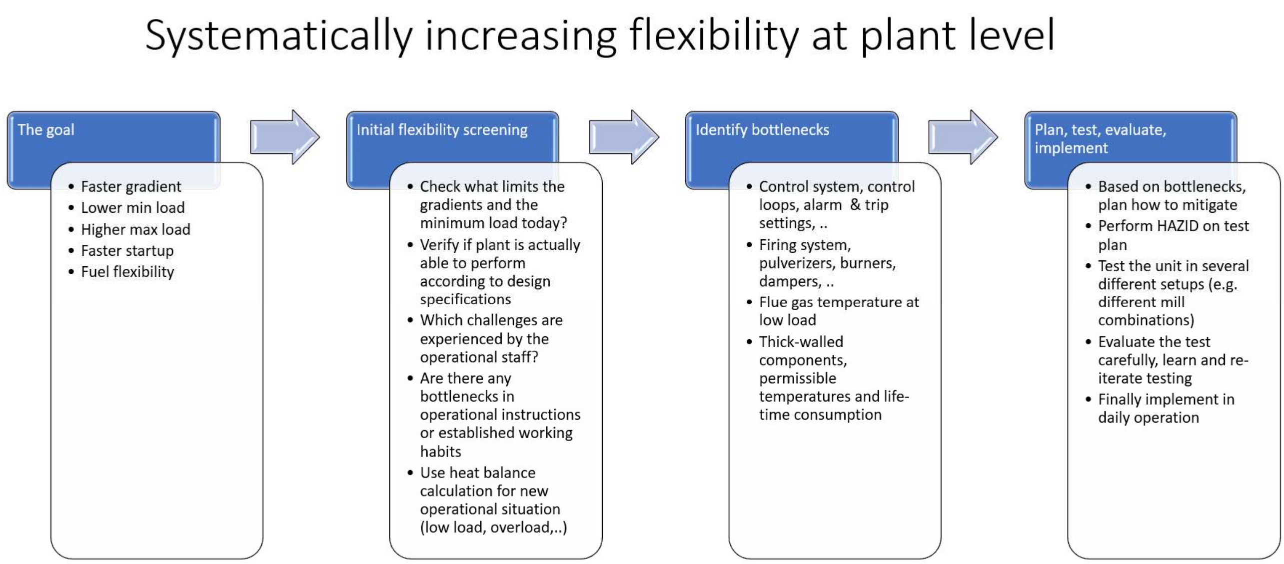


Figure 19 Method used for increasing flexibility

Actually, the method is not a textbook model, it is rather a model that emerged along the way during the years when Renewable Energy was introduced in larger and larger degree in Denmark.

1. First action is to define the **goals** of the higher flexibility, i.e. faster gradients, lower minimum load, higher maximum load, faster start-up times or usage of other fuels.
2. With this done the next step is to perform an **initial flexibility screening** and check what limits the minimum load and gradients today. This can include a performance test to check if the plant is able to deliver according to specifications, interviewing the operational staff to examine their experiences, identify bottlenecks in operational instructions or working habits as well as using heat balance calculations for the new operational situation to verify its possibilities.
3. After all this data has been collected the third step has been to initially try to **identify the bottlenecks** in the plant. This can be for instance: constraints in the control loops or alarms and trip settings in the DCS, constraints in the firing system (minimum load for the coal mills or burners or even operation of control dampers), constraints in the Flue Gas system (maybe too low flue gas temperature at minimum load to keep the SCR system in operation or too low flue gas temperature to avoid acid condensation in the flue gas ducts) or constraints in the thick walled components ability to change temperature (boiler drum, thick walled steam headers or turbine housing or shafts).
4. Last step is to do some **real testing with the plant**. With the knowledge of assumed bottlenecks, it is important to make a test plan with mitigation actions if something goes differently than planned. After the best plan has been created, perform a risk assessment of the test plan and instruct the staff carefully before the test. Only when the complete plan is approved, and the entire measuring scheme is set up, perform the test. The tests will have to be done in different setups, e.g. with different mill combinations, different fuel,

different soot blowing history etc. in order to make the results robust for daily use. After the first test is performed and evaluated carefully, additional tests may be planned to investigate other aspects or, for example, go even lower in minimum load or with faster gradients. Several iterations of testing are normally necessary before the solution can be implemented in daily operation.

Typical bottlenecks found in Denmark

Based on experience with the Danish thermal fleet and other international plants, some typical bottlenecks can be identified. The figure below shows a series of typical bottlenecks split up into: Firing system, Boiler system, Air/Flue gas system and Steam Turbine system.

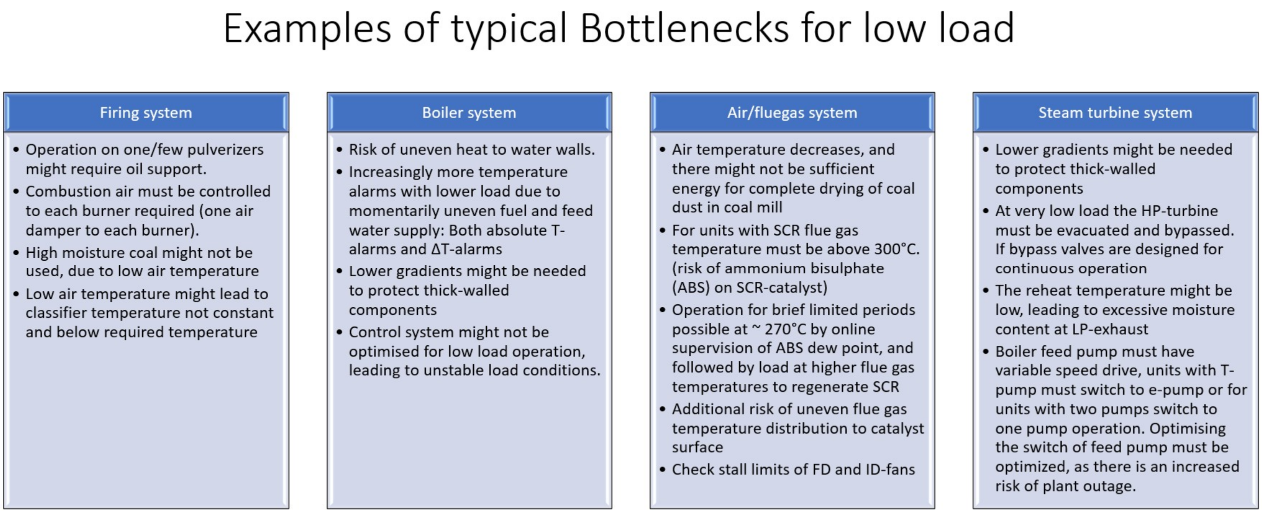


Figure 20. Bottlenecks for lower minimum load.

- For the **Firing system** a typical bottleneck how few coal mills the unit can run with. In Denmark the control range of the mills is large and most plants can run stable minimum load with two mills in operation without oil support. Some plants can even run stable minimum load on only one coal mill without oil support. A typical constraint is humidity of the coal. If the coal is very wet there might not be enough energy in the combustion air to dry the coal out in the mills at minimum load. A solution can be to avoid very wet coal for minimum load.
- For the **Boiler system** a typical bottleneck is uneven heat transfer to the water walls when only very few burners are in operation. Another typical constraint can be in the poorly optimized control loops of the firing or steam temperature control at low load. Fortunately, optimizing control loops is one of the cheaper bottlenecks to fix and a lot of work has been done in this regard in Denmark.
- The **Air/Flue gas system** typically has a main bottleneck in the low flue gas temperature, which occurs at minimum load because the selective catalytic reduction (SCR) plant typically requires flue gas to be warmer than 300°C for the catalyst to work properly. Also stall limitations of the air and flue gas fans might be a bottleneck which has to be solved.

- For the **Steam turbine system** a typical bottleneck for fast gradients and (maybe) also minimum load is the gradients of the very thick walled housing and the thick shaft of the turbine. These limits must be respected and lead to an automatically limit of the gradients when exceeded. Also, the switch over between feed water turbine driven pump and electric driven pump or even between several electric driven pumps is typically a bottleneck and the switching needs to be automated to work completely automatic without operator intervention.

4. Criteria and insights on the selection process

The overall goal of the assignment is to form the basis for test pilot projects, aiming at proving the ability to perform thermal power flexibility in the selected power plants. To progress on achieving the goals of enhancing the flexibility of coal fired power unit, it will be necessary to gather more detailed information about the individual coal-based power units. To further investigate the possibility of increased flexibilities, it will be necessary to have more details from the individual power units, which could be divided into units of similar technology for burners, fuel system, combustion air, steam and water system, flue gas system, turbine system, condensate and cooling system. This should result in a more detailed analysis of the level of instrumentation, type of actuators and technology level of the DCS. The degree of automation and the process control structures, must be investigated to evaluate the possibility by upgrading the control philosophy in the DCS as well as the critical equipment.

To approach this in a practical and systematic way, the task of obtaining more flexibility, a few representative power units should be selected and studied in more detail. If possible, it would be best to choose a specific number of power plants with a technology that are representative for a number of similar plants, in order to utilize findings from the tests.

Any thermal power unit which is going to be renewed as part of a scheduled maintenance should be seriously considered for upgrading the units or entire plant to meet the requirement for efficient operation, flexibility, and environmental compliance.

It is suggested that the technologies required for increased flexibilities on the selected power units are divided into categories from easy implementation to more complex implementation, and evaluate the time and cost needed to implement the installation.

Initially the selection should preferably be divided into categories defined by large base load units (> 400 MW) and super-critical units, which are more costly, time consuming and maybe more complicated to upgrade and sub-critical smaller power units (< 250 MW) which amounts to about 1/3 of the installed coal fired power units in the Indian power system. The smaller power units are more likely to benefit from refurbishment for low load and flexible operations.

Other factors for increased flexibilities related to updating the burner and air system, water and steam system, should also preferably be subdivided into categories for ease of implementation, and could be evaluated for which sequence they may favorable be implemented regarding time, and schedules maintenance.

One of the key aspects in achieving low operation is in education and expertise of the operator staff in understanding the nature of the power units when operating at low load. It is important to create a dialog with the operators when starting to study a power unit to gain knowledge about the daily challenging situations of the power units. In Denmark there has been a culture where the engineering of a power plant has greatly benefited by incorporating the operator staff knowledge of the power plant nature.

As an example, one of the easiest and cheapest systems to start looking into, is the DCS system; i.e. to see the level of automation, how the automation has been implemented, and how the control structures are designed. This can often be utilized and optimized, with a quick result of increased flexibility by adjusting and trimming parameters where possible and using recorded process value to evaluate the influence of different process values. Since 2/3 of the coal fired power units have been installed after 2003 it is likely that they are equipped with advanced DCS-systems, which can be utilized to improve the control structures and improve logic control to minimize operator interventions.

A key factor for low load operation is stable combustion and flame detection, and a strict HP (High Pressure) and RH (Re Heater) steam temperature control, to minimize the thermal stress of the boiler and the turbine. In Denmark all power units are using model-based SH (Super Heater) and RH dynamics, for precise and fast control of HP steam and RH steam temperature. A higher degree of automation can be easily implemented by utilizing automatic sequence which will assist the operators by minimizing manual interventions and will ensure that all the necessary components are started and stopped, not only in the right sequence, but also at the right time with the set-points adjusted according to the changing loads.

Any change for low load operation and flexibility, is better than none. Even the smallest update can prove beneficial by understanding the process and learning how to proceed on a larger scale. For similar power units, it is also possible to implement different solutions and compare which technological solutions has the highest potential before installing on a larger scale.

4.1. Danish experience on selection process

In order to replicate the Danish learnings and experiences in Indian power plants, it is essential to describe transparently the selection process to select the power plants for the pilot project.

The selection process aims at selecting two power plant units very qualified for the flexibilisation process. The applied criteria are relevant but not entirely comprehensive.

Based on the historical Danish experience, the recommended criteria, which can be applied in future selection processes, are:

- ***Technology (typicality)***
  It will be valuable to select units of which type there are many using the same technology to be able to reuse the experiences gained; i.e., if tests are done at one unit which has 35 similar sister-units the work can be reused 35 times. Similarities of technology can be

within e.g., boiler type, coal mill type, burner type, air system configuration, turbine type, cooling tower type, I&C type etc.

- ***Flexibility***

  The potential for flexibilisation is different for units with a high flexibility relative to units with a low degree of flexibilisation. Selecting already flexible units and improve them even further will set new standards while working with low flexibility units will result in an overall larger result in the fleet.

- ***Age***

  An important criterion is the age of the selected units. Should the focus be on young or older units? How long a residual lifetime should the units have, e.g., 100.000 hours, 200.000 hours, 300.000 hours etc.? Also consider if a plant is old but has a planned upgrade to prolong the lifetime (lifetime extension). The longer the remaining lifetime is, the more benefit is gained from flexibilisation.

- ***Size***

  The potential for flexibilisation is higher, the larger the selected unit is. On the other side, a large unit will be more costly to modify than smaller units.

- ***Location***

  In which regions of the country is it most relevant to do the first pilot projects? It makes good sense to select units in an area where RE is expected to expand and the power system will have to accommodate.

- ***Contractual limitations***

  One important selection criteria is to select units not limited by contractual constraints in their operation, e.g., if a unit has a long-term contract to produce at full load it makes less sense to start working on flexibility. Such bindings should be avoided or mitigated.

- ***Ownership***

  It may be important to select pilot units with different kind of ownership.

  - Inter-State Generating Stations (ISGS)
  - State Generating Stations (SGS)
  - Independent Power Producers (IPP)

- ***Power market***

  Agility and robustness of a certain level in the power market is necessary to accommodate the testing period.

- ***Plant personnel***

  The plant personnel are preferably open minded, flexible, interested and skilled.

- ***Plant readiness***

  The selected unit shall preferably be in a good condition without any known obstacles that can interfere with the tests.

4.2. NTPC and CEA's selection criteria

CEA/KPCL and NTPC provided a list of potential power plants suitable for investigating the potential for flexibilisation (See Appendix B – List of Power Plants).

Based on the above-mentioned criteria, CEA/KPCL and NTPC identified suitable thermal power plants for potential pilot projects about plant flexibility.

The power plants and units shortlisted for the flexibility tests are:

- Ramagundam Power station Unit 7 (NTPC), 500 MW
- Raichur Thermal Power Stations Unit 2 (owned by KPCL), 210 MW

The Danish experts, being part of the process, assesses that the selected power plant units are suitable, although not all selection criteria have been considered.

The evaluation of the selection criteria is elaborated in the following paragraphs, based on the considerations proposed at the beginning of this chapter.

Choosing plants in regions with actual need for flexibility

The selected plants will be ready in good time to accommodate more renewable energy into the system. By this selection, the learnings can benefit other similar plants as fast as possible.
Benefits:

- High local motivation because the need is already there
- High motivation for converting test results into daily routines/procedures
- High yield from learnings to benefit similar plants

Access to several coal types

The coal type and specification are a key issue in the flexibilisation process. The more insight into the influence of different coal types available, the easier it is to apply the results in plants, which have slightly different coal types.
Benefits:

- Be able to test and analyse impact of several coal types. (e.g., regarding min. low ability)
- Insight into flame stability in low load
- Insight into coal mill performance

Choosing plants of two different types

By selecting standardized units that represent a number of comparable units the findings are more easily be replicated to a larger number of plants. By selecting two different standard units the potential for replication is even bigger.

Benefit:

- Large potential for replication (potential of flexibility measures roll-out on several plants in parallel)

Choosing plants with low efficiency reduction and minimum load

Operating a unit in low load will often result in reduced unit efficiency. By selecting units which maintain the efficiency in low load, the marginal cost will be reduced and the economy better.

Benefits:

- Cost optimization due to saved fuel

4.3. Plants description

The following sections give an introductory description to the plants selected for pilot projects; the attributes described are regarded to be relevant for the pilot projects. The description and the following analyses are based on the technical analysis, performed by Danish experts, on the structural data about the two plants, kindly shared by CEA, KPCL and NTPC.

Raichur Unit 3

RAICHUR unit 3 is a 210 MW_e unit with a natural circulation Boiler Bharat Heavy Electricals Limited (BHEL) make, with tilted tangential firing, 6 bowl mills and 24 burners in 6 levels. Each mill supplies the four corner burners in one elevation. The unit is designed for 5 mill operation with one mill in stand-by.

The performance data with design coal, Maximum Continuous Rating (MCR):

- Coal quality HHV (kcal/kg): 3650
- Design pressure (kg/cm2): drum: 175.8, SH:155
- Live steam flow (t/h): 685
- Live steam temperature (°C): 540
- Feed water temperature (°C): 244
- Re-heater outlet (t/h): 594
- Re-heater temperature (°C): 540
- Re-heater pressure outlet (kg/cm2): 37.2
- Flue-gas temperature furnace (°C): 1183
- Flue-gas temperature APH outlet (°C): 142
- LP exhaust pressure (ata): 0,1033

Fans:

- Two VFD ID fans
- Two constant speed FD fans with pitch control

- Two PA fans with inlet damper control

Boiler feed pumps:

- Two Motor driven Boiler feed water pumps and booster pumps

Three Condensate pre-heaters and two HP feed water pre-heaters.
The normal load range for the unit is 210 (NCR) to 126 (60%) MW_e.

Ramagundam Unit 7

RAMAGUNDAM unit 7 is a 500 MW_e unit with a controlled circulation Boiler BHEL make, with tilted tangential firing, 10 bowl mills and 40 burners in 10 levels. Each mill supplies the four corner burners in one elevation. The unit is designed for 7 mill operation with 3 mills in stand-by (according to the document BOILER DRAWING & DATA provided by NTPC).
The performance data with design coal, Boiler Maximum Continuous Rating (BMCR):

- Coal quality HHV (kcal/kg): 3400
- Design pressure (kg/cm2): drum: 207, SH:178
- Live steam flow (t/h): 1675
- Live steam temperature (°C): 540
- Feed water temperature (°C): 254
- Re-heater outlet (t/h): 1387.2
- Re-heater temperature (°C): 540
- Re-heater pressure outlet (kg/cm2): 42.5
- Flue-gas temperature furnace (°C): 1379
- Flue-gas temperature APH outlet (°C): 128
- LP exhaust pressure (bar): 0,1027

Fans:

- Two VFD ID fans
- Two constant speed FD fans with pitch control
- Two PA fans with variable inlet guide vanes

Boiler feed pumps:

- One Turbine driven Feed water pump and booster pump
- One Motor driven Boiler feed water pump and booster pump

Three Condensate pre-heaters and two HP feed water pre-heaters. The normal load range for the unit is 525 (BMCR) to 250 (50%) MW_e.

5. Potential opportunities, possibilities and assumptions for thermal flexibilisation at Raichur and Ramagundam

Following a detailed analyses of the data provided about the Raichur KPCL and Ramagundam power plants, this section lists the potential opportunities and possibilities to enhance the flexible capabilities of the power plants under study, to increase the ramp rates, and to deal with the changes in plant efficiency. The list is proposed for both plants, as the opportunities suggested are all relevant for both units.

Both boilers are drum type with respectively natural (Raichur Unit 3) and controlled (Ramagundam Unit 7) circulation with tilted tangential firing.

The boiler and firing systems are the primary focus of this work. Consequences for turbine and condenser systems, e.g. investigations regarding increased moisture content at LP turbine outlet causing erosion risk, are not considered. The moisture content will depend heavily on the re-heater temperature which only will be verified during the pilot trials.

Installed Primary Air steam pre-heaters is assumed to be able to keep up the regenerative air pre-heater temperatures during low load to prevent corrosion of the air pre-heaters. This assumption shall be verified with the technical teams.

5.1. Potential interventions to enhance plant flexibility

Based on the data analyzed, it is suggested to consider and carry out a broad range of interventions, both from an operational and refurbishment perspective. Considering that this plant type (medium size unit with tilting tangential firing) is very common in the Indian power system, similar interventions could then be replicated to all other power plants similar in type.

5.1.1. Preconditions

Increased maintenance level of the combustion system.

A fundamental precondition is that critical equipment is in best possible condition. Especially:

i. Mill bowl and rollers
ii. Classifier vanes
iii. SA dampers and actuators
iv. Burner pipes and dampers

b) Measurements ranges extended to cover low loads

The accuracy of especially flow measurements can deteriorate in low load and adversely affect the corresponding control loops like PA flow and SH spray control.

Measures to reach lower loads

a) Reducing the number of operating mills and maintaining a relative high mill load. By this approach the velocities in the combustion system will be unaffected and the flames will remain stable. It is expected that the upmost burners will be operated in low loads to maximize the re-heater outlet temperature. Likewise is the burner tilt expected to be put into max position at +30°.

b) Combine furnace temperature measurement with burner flame detection. The idea is that a poor flame signal at low load operation may be not equivalent to a poor flame. This will include involvement of an independent authority for design approval. This measure has not yet been implemented in Denmark.

c) Bypass of High-pressure feedwater Heaters. Bypassing the feed-water heaters will further lower the min. load limit. The efficiency will decrease, and the power output will drop. The Danish plants are all equipped with waterside bypass which simplifies this approach. The turbine limitations regarding axial displacement and vibrations must be respected.

d) Increasing the Condenser pressure. Increased condenser pressure will lower the power output and minimize the water droplet content in the turbine exhaust. The limit will be determined by the turbine's allowable operation range.

e) Increase fluegas temperature / lower combustion air temperatures. Consider bypass of the air pre-heaters and/or economizer. Lowering the heat input into the furnace from the combustion air system will lower the steam production and the power output. In a Danish context, this is implemented primarily as an ECO-bypass to maintain the flue-gas temperature before the SCR system.

The three last measures (c, d and e) will likely reduce the plant efficiency, which makes them less attractive. If such measures are applied the plant must be compensated appropriately to cover the extra fuel cost.

Measures to improve the combustion process

To improve the combustion, without oil support, several activities are recommended. An improved combustion will enable lower loads. The list is not in order of priority but rather a non-exhaustive list of potential opportunities:

a) The coals to be used should be clarified concerning ignition reactivity (coal rank, volatile, moisture, ash). "Good" coal for low loads should be reserved in the coal yard. In a large power plant with several units, the coal yard can be divided into a number of slots containing different coal qualities that can be used in dedicated units.

b) The coal dust flow distribution from mills to burners should be as "even" as possible. Optimization of the distribution is essential. The usual orifice valves are subject to heavy erosion due to the abrasive nature of the Indian coal. New, more resilient, valve designs are available and may be considered. The roping phenomena must be minimized and can be mitigated by newer valves and riffle boxes.

c) Optimized coal dust fineness from mill outlets by adjusting the classifier setting, but without decreasing the mill capacity at max load. The specific mills used for low loads can be optimized for this especially and have a different setting than other high load mills.

d) Optimize the air/coal ratio curve for the coal mills. From analyzing the received data, we have found that the original BHEL curve is still in use. The coal pipe flow velocities must respect ignition velocities in the burner/furnace as well as min. p.f. transport velocity for avoiding settlements in the pipes.

e) Optimize the roller/bowl grinding pressure.

f) Identify best mill load where flame stability is optimal.

g) Best possible combustion air (secondary air) distribution among the burners in each burner level (from the same mill) by adjusting the secondary air (SA) distribution dampers.

h) Coarse ash filters in the air duct after the regenerative air-preheaters. The idea is to reduce the ash amount in the burner zone to improve ignition and flame detecting. This is a novel idea which is not been tried out in Danish plants.

i) General optimization of existing flame scanners for operation at lower load, e.g. considering position/angle, different burner levels, coal type/quality.

j) Installation of and new better flame scanners for each burner.

k) Installation of a flame stabilizer. Early ignition close to the stabilizer due to the “Bluff Body” effect. This measure is very dependent on the burner supplier.

l) Installation of new dynamic classifiers.
The pulverized fuel (p.f.) dust fineness will be considerably improved, according to Loeche (OEM) the fineness can be improved from 70% to up to 85% passing through a 200 mesh. Finer p.f. will improve the stability of the flames and make the system more resistant to changes in coal quality. (See appendix).

m) Installation of gravimetric feeders. Gravimetric feeders are more precise than the volumetric currently used in most Indian power plant. A gravimetric feeder will compensate the variation in bulk density and feeds a fixed weight of coal in response to boiler fuel demand.

n) Optimization of control loops. The control loops are usually only optimized for nominal load and needs to be reviewed for low loads:
   - O_2 control
   - De-super-heater spray control
   - Feed-water control
   - Boiler drum level control

5.2. Increasing Ramp Rates

Danish power plants have typical a ramp rate of 4-6 %/min. of nominal load. Fast ramping leads to fast material temperature changes and thermal stresses.
Achieving fast ramping rates requires focus on two different areas:

1. Thermal stress surveillance
2. Equipment capabilities

In Denmark, critical thick-walled components are monitored, and a lifetime calculator is usually applied. The lifetime calculator accounts both for creep and fatigue and are based on the standard DIN EN 12952 [13] and on temperature difference measurements in the components. It is expected that life-time consumption in drum-boilers is less than for super-critical boilers i.e. the drum pressure-/temperature is almost constant.

If the ramp rate is to be improved, then key equipment must be controlled for being able to produce the necessary gradients and stability:

- Coal feeders and transport system
- Coal mill motor and drives
- Pumps and fans
- Necessary motor power and momentum
- Actuators for valves, pumps and fans
- Drum level control
- Unit control
- Control system

5.3. Efficiency Reductions

Operating in low loads will, especially for drum boilers, result in deviating HP/RH temperatures, which will reduce the plant efficiency. For instance, a 30°C reduction in both HP and RH temperatures will reduce the plant efficiency approx. 0.65%-point leading to a proportional increase in OPEX fuel cost. The precise temperature reductions for Raichur and Ramagundam can only be determined during the pilot trials.

The higher purpose for low load operation in Denmark is often to keep the unit in operation, to avoid start-up costs.

In a free power market like the Danish, the low load capability will only be sold when the electricity price is economically attractive. This stresses the importance of knowing the exact marginal cost of operating a plant in different modes and loads. A plant’s services shall only be sold when it has economically positive contribution.

Hence, the remuneration for flexibility, e.g. through the Indian power market, should be adapted if the power plants have to operate flexibly with low loads and with higher ramp rates.

5.4. Raichur Unit 3: Low load suggestions

Table 5-1 suggests the combustion parameters for two possible low load targets, 40% and 35% by reducing the number of operating coal mills and maintaining a high mill load.

Table 5-1 Suggested combustion parameters for low loads in Raichur

Power	MW	210	126	84	73,5
Plant load	%	100	60	40	35
No mills	#	5	3	2	2
Mill load	%	79	81	83,2	72,8
Airflow per mill	t/h	54	55	55,8	51,6
Burner tilt	°	12	25	30	30
Coal	t/h	136	84	57,5	50,3
Coal per mill	t/h	27,2	28,0	28,8	25,2
Air/coal ratio	-	1,99	1,96	1,94	2,05
HHV	kcal/kg	3650	3650	3650	3650
Fired fuel	M.kcal/h	496	307	210	184
CO_2	t/h	184	114	78	68

The table is based on available design data (*Boiler specifications and performance parameter,* as per data shared). If the actual boiler performance data differs from the predictions by the manufacturer, BHEL, the table must be updated accordingly.

It is recommended to use oil-support when reducing the number of operating mills. If the test is successful it is recommended to try the load reduction without oil support.

The following suggestions are minor measures that can be used to further reduce the power output by lowering the plant efficiency. The calculations are based on received as-built Heat Balance Diagrams (HBD's).

Bypass of HP pre-heaters

If the HP pre-heaters are bypassed in 60% load, the power output will decrease to approx. 3.6 MW, equivalent to a load reduction of 3% with the same amount of fuel input 307x106 kcal/h. The feed water temperature will drop to the deaerator temperature approx. 148°C. The turbine axial displacement and vibration level must be verified to be within the normal operation range.

Increase turbine exhaust pressure

If the exhaust pressure is increased from 0.0812 to 0.1033 ata, the power output is reduced app. 1.9 MW and the moisture content is reduced approx. 1%. This reduction is according to the HBD's at the specific loads. It is expected that a further pressure increase is achievable, but the turbine limitations must be respected.

5.5. Ramagundam Unit 7: Low load suggestions

Table 5-2 suggests the combustion parameters for four possible low load targets, based 3 and 2 operating coal mills respectively.

Table 5-2 Suggested combustion parameters for low loads in Ramagundam

Power	MW	500	250	200	184	150	123
Plant load	%	100	50	40	37	30	25
No mills	#	6	4	**3**	**3**	**2**	**2**
Mill load	%	87	72	78	72	88	72
Airflow per mill	t/h	97	91	94	91	97	91
Burner tilt	°	-3	24	30	30	30	30
Coal	t/h	328	180	147	135	110	90
Coal per mill	t/h	55	45	49	45	55	45
Air/coal ratio	-	1,77	2,01	1,91	2,01	1,76	2,00
HHV	kcal/kg	3400	3400	3400	3400	3400	3400
Fired fuel	M.kcal/h	1116	613	500	460	375	308
CO_2	t/h	425	233	190	175	143	117

The table is based on available design data (*Predicted Performance Data, drw.no TP-DG-202-110-2511*, as per data shared). If the actual boiler performance data differs from the predictions by BHEL, the table must be updated accordingly. It is recommended to use oil-support when reducing the number of operating mills. If the test is successful it is recommended to try the load reduction without oil support. If the plant is operated with 3 coal mills, it is expected that the (power) load can be reduced to app. 37% and if the combustion system is sufficiently stable, the load can be reduced further to as low as 25%

Turbine exhaust water content must be verified being within the acceptable range. To high water content can eventually erode the last turbine stage blading. Eventual counter-measures needed include increase exhaust pressure or increase RH temp.

The following suggestions are minor measures that can be used to further reduce the power output by lowering the plant efficiency. The projections are based on Raichur data by proportionality and must be regarded as preliminary, as HBD's were not available in the data provided by NTPC.

Bypass of HP pre-heaters

If the HP pre-heaters are bypassed in 50% load, the power output will decrease to approx. 6 MW, equivalent to a load reduction of 2% with the same amount of fuel input.

Increase turbine exhaust pressure

If the exhaust pressure is increased 23 mbar, the power output is reduced app. 3.2 MW in 50% load with same fuel input.

5.6. Preliminary recommendations Raichur and Ramagundam

In theory, reaching the required low loads seams uncomplicated, in practice the situation can be very different.

The variation in coal quality is the primary parameter that it is suggested to focus on first. Both plants are recommended to initiate measures to reduce the quality variation. The following suggestions are only expert suggestions based on the data received. However, further considerations should be discussed about the feasibility of such solutions.

- Increase the coal blending performed in the coal yard.
- Identify a mine or a mineshaft that produces coal with less variation.
- Reserve slots in the coal yard for different coal qualities.
- Identify when a quality change reaches the burners in good time before, and apply oil support during the change-over.

The size of raw coal fed into the mill and the amount are important prerequisites before fuel pulverizing. Generally, raw coal size should be consistently less than 19 mm.

There are no coal mines in Denmark, i.e. our experience with coal yard optimization is somewhat different than the Indian experience. In Denmark we usually blend two or three different coal qualities for two purposes, 1) to be able to apply cheaper coals and 2) to optimize the combustion process as well as the ash quality.

A prerequisite for a successful process is that all equipment must be in good maintenance condition and not worn out. The best approach is to do an initial performance test to verify that key equipment complies with the specifications. In Denmark, the mills are inspected and maintained at intervals of approx. 5000 operating hours. Every 25.000 hour the mill internals like rollers and grinding table are replaced.

As the grinding elements wear, the grinding efficiency of the mill deteriorates. The type and rate of wear of grinding elements depend primarily on the coal quality. Ensuring that all grinding elements of the mill are in good condition, properly aligned and preloaded, is paramount for optimum mill operation

All measures that can be executed without refurbishment of new equipment must be initiated as soon as possible, which involves:

- Optimizing mill performance:
  - Grinding force
  - Classifier adjustment
  - Air/coal ratio curve
  - Mill load
  - Coal and air distribution in coal pipes
- Optimize SA distribution
- Optimize the flame scanners

The optimization will involve measurements of the coal p.f. quality by sampling from the individual coal pipes as well as analysis of UBC.

We suggest that a small work group is put together consisting of operational and maintenance personnel as well as plant engineering (combustion and control engineers). The group shall produce a report that documents the optimizing process and results.

Only hereafter it is suggested to proceed with the first low load test. We recommend that the normal low load is documented in a pretest.

5.7. Preliminary assessment

The analysis of both plants showed two standard design base load coal fired power plants, very well equipped to operate at higher loads. Both plants are designed very conservative for operating with problematic coals. The plants are furnished with standard combustion equipment which are not ideal for operating at lower load without some refurbishments.

Combustion and the fuel flow optimization must start with improving particle fineness and mill performance. Before such optimization takes place, accurate and reliable real time measurements are required.

We have found two potentials for optimizing the coal mills by i) installing dynamic classifiers, and for ii) refurbishing the coal burners with flame holders. Both suggestions will improve the combustion process considerably and increase the stability in both high and lower loads as well as reduce the UBC. Dynamic classifiers are not expected to reduce the NOx level, only air staging/optimization can improve this.

Another promising potential is replacing the raw coal feeders with gravimetric based feeders, which will increase the accuracy and overall quality of the grinding and combustion processes.

However, no final suggestion for these new installations can be done before necessary low load tests have been performed.

5.8. Proposed next steps

It is suggested that the process continues in different steps. First a preliminary step that prepares the plants by performing additional maintenance and analyzing if and how the coal yard can be used better. Then it is suggested to perform low load tests which shall result in an analysis of which refurbishments are necessary in the long term, if any.

Primary steps:

1. Analyze how the coal yard can be optimized for storing different quality coals for minimizing the fluctuations.
2. Optimizing the current combustion process in both low and high loads. Without refurbishments but performing a major overhaul on mills and burners exchanging worn out equipment details. Focusing on coal mills and burners controls like classifier vanes, mill rollers, mill bowl etc. This work can optionally be performed with or without the involvement of OEM's like BHEL.

Next steps:

3. Document current low load

   A non-exhaustive list includes: UBC, NO_X, CO, O2, HP/RH temperatures, HP/RH sprays, flame scanner signals, mill DP, Coal/PA ratio, aux power, Heat-rate, oil etc.

4. Perform 1st low load test

   Reduce the load corresponding to taking one mill out of operation while supporting with oil firing. While maintaining a high mill load, slowly reduce the oil support. This test shall be systematically documented and analyzed, and problems identified.

5. The low load test shall be repeated until best possible result is achieved.
6. The test analyze shall conclude the best next step on how to reach the goal. Some refurbishment must be expected

Next steps:

7. Involvement of OEM for refurbishments.
8. Retest and document the results.

Based on the Danish experience developed throughout the years, which led to the modification of the Danish power plants both from a technical as well as from an operational perspective, the Danish experts are confident that such suggestions would lead to enhancement in the flexible capabilities for both Raichur and Ramagundam. This would allow the two plants under study to operate flexibility in the power system, accommodating larger share of variable RES in the respective States of Karnataka and Telangana and, consequently, reducing potential CO_2 and other GHG emissions.

6. Planning of the pilot projects

The pilot projects in both Ramagundam and Raichur are envisaged to follow the same roadmap for success, presented visually in the image below, as well as perform preliminary steps.

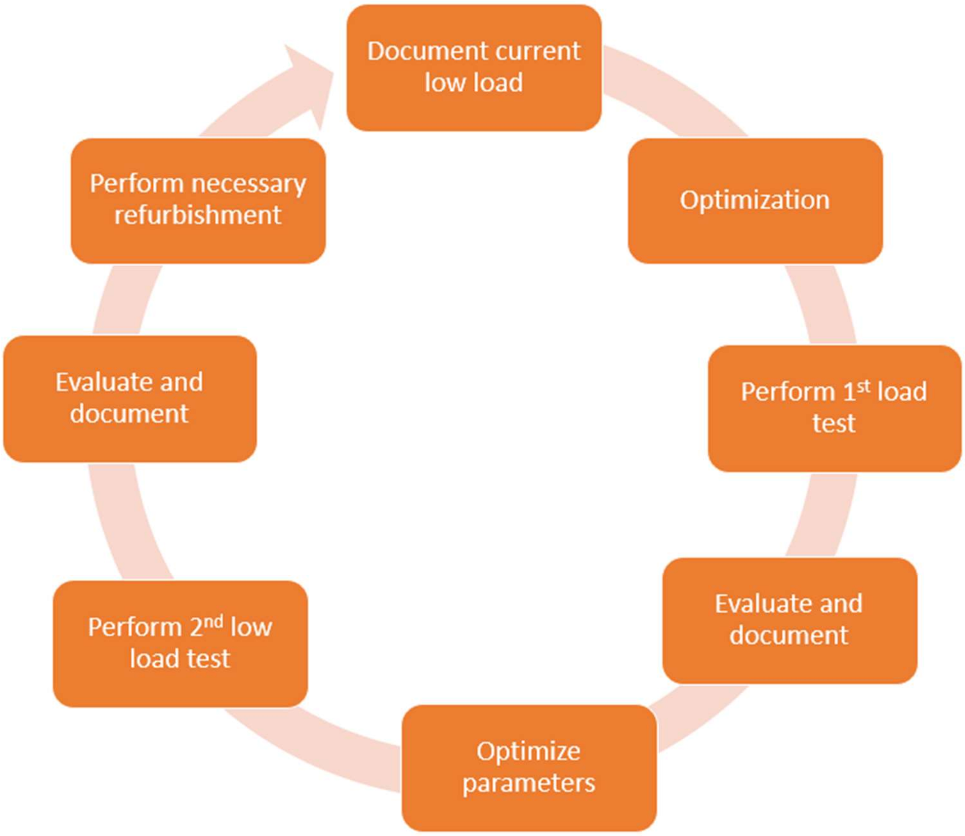


Figure 21 Roadmap for success for low load tests

Preliminary steps:

1. The procedure is advancement by controlled minor steps, documentation, and involvement of every level in the organizations.
2. Reports and documentations are envisaged to be performed by the power plants operators.
3. A preliminary step before initiating the pilots, is to perform an overhaul of the low load coal mills and burners, exchanging worn out equipment details like classifier vanes, mill rollers, mill bowl etc.
4. The control system must be prepared for operating in a lower load than usual.

Document the current low load:

- The first step is to document the current low load. This is a very important step that will provide a frame of reference for all the following steps, i.e. the benchmark. Based on the data recorded, the Danish experts from COWI will propose tailored suggestions before the first low load test.

Perform 1st low load test:

- The 1st low load test shall be performed with one less coal mill in operation. The load reduction must be executed carefully with oil support during the transition. The coal mill load is expected to be high (≥70%). The goal is operation without oil support. The operators should keep in mind that, being a test, the achievement of low load may not be possible!

Evaluate and document the 1st low load test:

- The evaluation and documentation of the 1st low load test shall focus on the combustion system and the identified problems during the test. The restricting bottlenecks shall be described in detail in the report. The Danish side will assist on the task by providing a table of content and indications about which parameters should be considered for the evaluation and how to assess them.

Optimize parameters:

The subsequent step is optimizing the combustion parameters like:

- PA/coal ratio
- SA/TA ratio
- Grinding pressure
- Classifier setting
- Trimming of the p.f. distribution from the mills
- Control loops if necessary

If the 1st low load test reveals any bottlenecks they must be addressed carefully. This will be done as a joint effort between the Danish and Indian experts.

Perform 2nd low load test:

- The 2nd low load test shall be performed when the optimizing process and all bottlenecks has been addressed.

Evaluate and document the 2nd low load test:

- After a thorough report a number of bottlenecks are expected to be identified.

Perform necessary refurbishments (and document):

- Mitigating the bottlenecks and other problems are expected to involve some refurbishment, which has to be discussed and analyzed carefully before a joint proposal is agreed, between the experts and the management.
- The pilot project shall then proceed and potentially conclude by documenting the improvements gained by refurbishments.
- Afterwards, upon completion and success of the pilots, a similar approach can be repeated to all the other plants in the fleet, to make sure a similar low load can be achieved in other plants.

6.1. Ramagundam pilot plan

During the meeting at Ramagundam on April 29th 2022, the following timeline and milestones were discussed and agreed.

Table 6-1 Ramagundam pilot plan

Ramagundam pilot plan	Date	To Do list	
		Ramagundam	COWI
Document current low load	01-08-2022	Report	Data list
Suggestions from Cowi	15-08-2022	-	X
Optimizations	15-10-2022	X	-
1st low load test	15-11-2022	X	-
1st evaluation report	30-11-2022	X	Suggestion for content and review
Meeting (NTPC, DEA, COWI)	07-12-2022	X	X
2nd optimization	TBD	X	
2nd low load test and ramp test	TBD	X	
2nd evaluation report	TBD	X	
Eventual refurbishments	TBD	X	

The plan deviates from the general suggested plan, i.e. an optimization is performed before the 1st low load test, as requested by the Indian partners. This deviation can speed the process up and is an acceptable variance. The Danish experts from COWI will be present and assist during the low load test and optimization initiatives. After the 1st test, and based on the results, new dates will be agreed together for the 2nd optimization, low load test, evaluation, documentation, implementation and eventual refurbishment.

6.2. Raichur pilot plan

During the meeting at Raichur on April 30th 2022, the following timeline and milestones were discussed and agreed.

Table 6-2 Raichur pilot plan

Raichur pilot plan	Date	To Do list	
		Raichur	COWI
Document current low load (60%)	01-08-2022	Report	Data list
Suggestions from Cowi	15-08-2022	-	X
1st optimizations initiatives	15-10-2022	X	-
1st low load test and ramp test	15-11-2022	X	-
1st evaluation report	30-11-2022	X	Suggestion for content and review
Meeting (KPCL, DEA, COWI)	07-12-2022	X	X
2nd optimization	TBD	X	
2nd low load test and ramp test	TBD	X	
2nd evaluation report	TBD	X	
Eventual refurbishments	TBD	X	

The proposed list of actions and timeline will be discussed within the technical and management teams at RTPS, and hereafter shared with the Danish colleagues as a final decision. The Danish experts from COWI will be present and assist during the low load test and optimization initiatives. After the 1st test, and based on the results, new dates will be agreed together for the 2nd optimization, low load test, evaluation, documentation, implementation and eventual refurbishment.

6.3. Data list

In preparation for the pilots, parameter data have to be recorded during low load operation of the units and to be shared, to monitor the development of the plant during operation.

The following list is a non-exhausting list of measurements and analysis that are imperative to perform during the low load tests. Such data should have been among the experts.

Coal	
	Ultimate analysis

Coal mills	
	Feeder flow
	PA inlet temperature
	PA flow
	Outlet temperature
	DP mill
	Mill pressure
	Power consumption
	Grinding pressure
	No of operating hours since overhaul
	Classifier settings
Coal pipes	Valve settings
	p.f. distribution
	p.f. fineness distribution

ID, PA and FD fans	
	Guide vane position – or pitch
	DP
	Flow
	Inlet temperature
	Outlet temperature
	Power consumption
	Load %

Burners	
	Valve/damper settings
	SA/TA settings
	SA/TA flow
	SA/TA temperatures
	SA/TA pressures
	Flame intensity
	Burner tilt
	Oil flow

Boiler combustion	
	Total fuel flow
	O2
	CO
	NOx
	UBC (bottom- and flyash)
	Furnace pressure
	Air inlet temperature
	Air temperature after Steam APH
	PA temperature after APH
	SA temperature after APH
	Total combustion air flow
	Total PA flow
	Total SA/TA flow
	Fluegas temperature after ECO
	Fluegas temperature after APH SA+SA
	O2 after APH SA+PA
	CO2, ppm, mercury levels

Boiler water/steam	
	Live steam temperature
	Live steam pressure
	Live steam flow
	Temperature before spray

	Temperature after spray
	Water injection flow
	Drum pressure
	Drum temperature
	Drum level
	Feed water flow
	Feed water temperature
	Feed water pressure
	ECO outlet temperature
Reheater	RH Inlet temperature
	RH Inlet pressure
	RH Inlet flow (calculated)
	RH Temperature before spray
	RH Temperature after spray
	RH Spray water flow
	RH outlet temperature
	RH outlet pressure
Soot blowing	ON/OFF
	Steam flow

Turbine	
	Temperature before turbine
	Pressure before turbine
	All bleed temperatures
	All bleed pressures
	HP outlet temperature
	HP outlet pressure
	Exhaust pressure
	Exhaust temperature
	Gross power
	Vibration level
	Axial displacement

Condensate/ feed water system	
	Temperature before and after all pre-heaters
	Steam condensate temperatures after PH
	Condensate flow
	Deaerator pressure
	Deaerator temperature
	Feed water flow
	BFW vibration level

Condenser/ cooling water	
	Condenser pressure
	Condenser temperature
	Cooling water inlet temperature
	Cooling water outlet temperature
	Cooling water flow

Ramping	
	Material temperatures of thick-walled components (headers)
	Material temperature gradients of thick-walled components (headers)

6.4. Preparations prior to testing

Some preparation should be done by the plant operators, before commencing the tests:

- Risk assessment
- Soot blowing
- Ashing (emptying of ash hoppers)
- Furnace water seal verified
- The unit must be isolated
- No known equipment problems
- Necessary equipment for taking out samples are available
- Eventual trainings

7. Pilot project in Ramagundam

The development of the pilot follows the roadmap for success, previously presented (See Figure 21).

7.1. Document the current low load

The paragraphs documents the achievable low load condition for Ramagundam unit 7, before any corrective measures are implemented. The test was performed exclusively by the staff at Ramagundam, without participation of the Danish project group from DEA and COWI; the test conditions and setup were not discussed and reviewed beforehand by DEA/COWI.

The date for the test was June 7th, 2022. Test data for one hour between 09:00 and 10:00 has been submitted for analysis by COWI. The purpose of the test is to document the current low-load; the data it will serve as a reference for upcoming tests at lower loads.

Summary

This low-load measurement shows a slightly higher low-load, 271 MW, than the anticipated 250 MW. From the data received, it was not entirely clear about the nature of the limiting factor(s). It would be beneficial if the test responsible can explain this at a later stage, as it is not evident from the measurements alone.

The test was performed with different settings than recommended, primarily low burner setting with 5 instead of 4 operating mills. Several key measurements and analysis, which are essential for the well-functioning of the pilot, were not available in the data set shared, especially coal and PF analyses.

The measurements indicates few challenges, which should be addressed by the test responsible:

- The HP steam pressure is 18 kg/cm^2 below the anticipated pressure.
- The O_2 % is very high, app. 3%-point higher than anticipated.
- 5 coal mills are in operation, one more than anticipated.
- The burner setting is not ideal by ABCDF, not using E. This result in an undesirable “firing gap”.
- The burner setting is “low firing”, while “high firing” is anticipated.

Main performance data (averaged)

The main test data is show in below table. For convenience “Predicted Performance Data” (drawing no TP-DG-202-110-2511) is also shown.

Table 7-1 Average Measurements

Description	Units	Ref 300	Ref 250	Measured
Load	%	60	50	54,2
Gross power	MW	300	250	271
Steam / Water:				
Superheater out	t/h	901,7	767	841,5
Reheater out	t/h	826	671,3	x
Feedwater	t/h	826,2	695	842,7
SH spray	t/h	75,5	72	45,1
RH spray	t/h	0	0	5,4
Air:				
AH outlet (PA)	t/h	380	359	x
AH outlet (SA)	t/h	571	432	x
Total Combustion Air	t/h	1157	1000	1178
Fuel:				
Coal	t/h	208,7	180,2	183,9
Steam / Water temperatures:				
Sat. Drum	°C	354	353	343,1
HT before spray	°C	404	402	423,3
HT after spray	°C	371	367	390,5
HT outlet	°C	540	540	541,6
RH inlet	°C	322	312	339,3
RH outlet	°C	540	540	524,2
Eco inlet	°C	230	222	220,7
Eco outlet	°C	305	297	x
Steam / Water pressures:				
HT outlet	kg/cm2 (g)	171,7	171,0	153,1
Drum	kg/cm2 (g)	177,0	174,7	159,8
ECO inlet	kg/cm2 (g)	180,3	178,0	147,2
RH inlet	kg/cm2 (g)	26,4	21,4	23,9
RH outlet	kg/cm2 (g)	25,1	20,3	22,7
Air:				
Ambient	°C	28	28	44,4
AH outlet (PA)	°C	273	259	283,6
AH outlet (SA)	°C	273	259	269
Gas:				
AH inlet	°C	291	276	283
AH outlet	°C	115	115	138,1
O_2	%	3,56	3,56	6,54
CO_2	%	15,56	15,56	6,94
NOx		x	x	300,2
Mills:				
No in operation		T4(G-K)	T4(G-K)	5(ABCDF)

The flame intensity was measured in each burner level, and shows the “firing gap” in level “E” clearly:

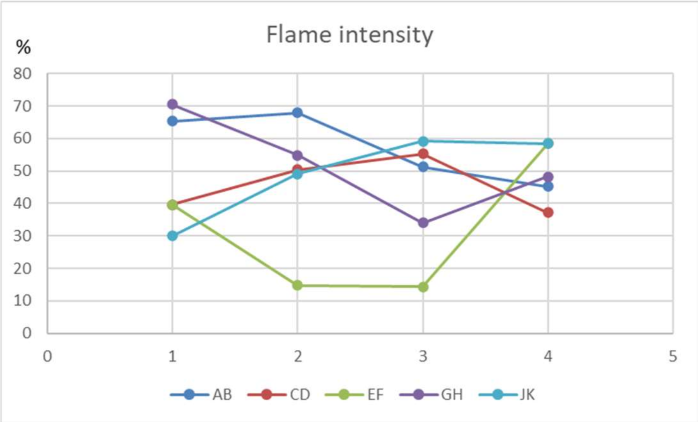


Figure 22 Flame Intensity

The following turbine and pre-heater measurements were recorded:

Table 7-2 Turbine and preheater measurements

Heaters	Measurement
LPH-1 COND I/L TEMP	45,4
LPH-2 COND I/L TEMP	59,5
LPH-3 COND I/L TEMP	94,4
Condensate flow	786,2
Deaerator pressure	3,8
TOTAL FW FLOW	842,7
TDBFP-A SUC FLOW	445,2
TDBFP-B SUC FLOW	434,4
Condenser pressure	0,1
Condenser temperature	40,8
Cooling water inlet temperature	31,2
Cooling water outlet temperature	38,1
Cooling water flow	58765,5
HPH-5A O/L DRAIN TEMP	149,5
HPH-5B O/L DRAIN TEMP	151,4
HPH-6A O/L DRAIN TEMP	187,8
HPH-6B O/L DRAIN TEMP	184,9

Turbine vibrations were measured for future reference:

Table 7-3 Vibrations

Vibrations	Measurement
Berg 1 vib Y	9,33
Berg 1 shaft vib Y	126,40
Berg 2 vib Y	4,26
Berg 2 shaft vib Y	91,65
Berg 3 vib Y	7,23
Berg 3 shaft vib Y	60,25
Berg 4 vib Y	6,15
Berg 4 shaft vib Y	44,29
Berg 5 vib Y	15,16
Berg 5shaft vib X	78,07
Berg 5 shaft vib Y	87,89
Berg 6 vib Y	11,31
Berg 6 shaft vib X	58,98
Berg 6 shaft vib Y	47,72
Berg 7 vib Y	9,51
Berg 7 shaft vib Y	71,10
Overhang Vibration reading	20,94
Overhang Vibration reading 23	9,73
ABS BRG VIB BRG - 1	4,98
SHFT VIB BRG - 1	190,21
ABS BRG VIB BRG - 2	4,80
SHFT VIB BRG - 2	103,33
ABS BRG VIB BRG - 3	7,70
SHFT VIB BRG - 3	66,29
ABS BRG VIB BRG - 4	10,57
SHFT VIB BRG - 4	86,57
GEN BRG VIB TE	14,48
GEN BRG VIB EE	8,69
ABS BRG VIB BRG - 7	9,82
SHFT VIB BRG - 7	64,77

Observations

- The measurements were all very stable during the test, the only major exception was the drum level measurement.
- The re-heater temperature is 16 °C below the predicted temperature while the RH water injection still in operation. Closing the injection will increase the RH temperature approx. 8K to 532°C. High RH temperature is required to keep the efficiency up and reduce the risk of erosion in last stage of the LP turbine.
- The HP steam pressure is 18 kg/cm^2 below the anticipated pressure. This should be discussed between the team and the experts.
- The ECO inlet pressure measurement is not correct as it is lower than both the HT- and drum pressures.
- The AH flue gas outlet temperature is higher than the anticipated, approx. 23°C - which is quite normal for an aged boiler.

- The AH PA temperature is equal to the ECO flue gas temperature measurement, while the SA temperature is 14K lower. Both the AH- and the ECO temperature most be serviced and recalibrated.
- The O_2 % is very high, approx. 3%-point higher than anticipated. High O_2 % results in increased fan power consumptions, and higher AH outlet temperatures. Hence lower efficiency. This should be discussed between the team and the experts.
- 5 coal mills are in operation, one more than anticipated, resulting in low mill loads. This should be discussed between the team and the experts.
- The burner setting is not ideal as ABCDF, not using E. This result in an undesirable “firing gap”. This should be discussed between the team and the experts.
- The mill outlet temperature is too low, approx. 13 °C lower than anticipated. This is not unusual as the flue gas temperature before the AH drops in lower loads drawing the PA temperature down. Too low mill temperature will worsen the combustion stability and increase the risk of tripping. The steam AH could and should have been put into operation to mitigate this.
- The PA inlet temperatures are low for the mills running at low loads (“A” and “F”)
- The burner setting is “low firing”. The burners in the lower part of the furnace are in operation. By setting a higher firing the RH temperature will increase. This should be discussed between the team and the experts.
- Flame intensities would benefit by avoiding the “firing gap”. The intensity gap will increase risk of tripping by combustion fluctuations.
- Drum level variations are excessive and should be addressed by checking the control structure. It looks like a PI control has been used, which is not desirable as a drum level control. The average drum level is -26.8 while std. variation is approx. 11.

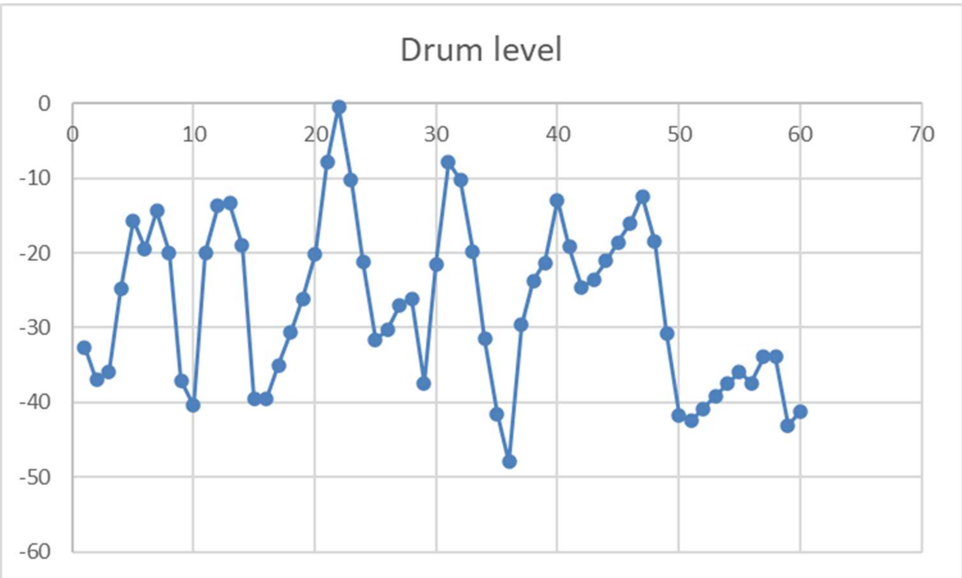


Figure 23 Drum level depiction

Suggestions for next tests

Based on the current measurement, the following operational settings are suggested to improve the combustion stability:

- Increase mill outlet temperature to 90 °C
- Use top mill/burner settings T4(G-K) / T3(H-K)
- Avoid firing gaps
- Increase mill load by reducing number of running mills
- Operate mills at same loads
- Reduce RH water injection, by optimizing the RH water injection control
- Reduce O_2 %
- Reduce drum level variations, by optimizing the control structure.

For best possible documentations of the test, it is essential to take coal samples of the fired coals and have an ultimate analysis made.

The following extra data are required to document the next tests, so to have a proper base of comparison among the tests performed:

- Coal analysis
- P.F. fineness
- P.F. flow measurements (coal pipe distribution)
- PA flow measurements
- DP coal mill
- UBC
- Coal mill motor power
- PA and SA temperatures after AH
- ECO outlet temperature
- H_2O content in flue-gas
- Condensate/feed-water temperatures after each pre-heater
- Turbine bleed temperatures and pressures for each bleed

The following measurements needs to be serviced and recalibrated:

- ECO inlet pressure
- ECO flue gas outlet temperature
- PA/SA AH outlet temperatures
- CO_2 measurement

Data shared in an Excel file format should clearly show measurement id-numbers and measurement units.

7.2. Evaluate and document the 1st and 2nd low load tests

7.2.1. Protocol and plan for flexible operation

The protocol and pilot is intended to detail the plan for the first low load test at Ramagundam unit 7. This should take place after the “current low load” (see Chapter 7.1) has been performed and documented in the document. The following two steps are: 1) to prepare the unit by performing necessary optimizations and 2) propose a plan for conducting the test at the plant, in preparation for the first low load test.

Protocol for Preparations

The following protocol refers to the preparations suggested to be addressed at the plant by the plant personnel. The plan is twofold, firstly some preparations at the plant is advisable, and secondly a plan for conducting the test at the plant is presented.

- **Measurements**

Based on the learnings from the *“Current Low-Load” test,* the following measurements are suggested to be addressed:

- AH PA temperature
- ECO flue-gas temperature
- ECO inlet pressure
- Feed water flow (FW FL)
  FW valve position (FDV14)
  FW pump speed (BFP-A, -B, -C) or just the ones in operation
  FW pump outlet pressure

The measurements previously shared are suspected to be erroneous and should be serviced and recalibrated.

- **Missing measurements**

Several necessary measurements were not available for the *“Current Low-Load” (*Chapter *7.1*), especially the following measurements were missing and should be made available:

- Coal mills:
  - Power consumption
  - Differential air pressure
  - Grinding pressure
  - Classifier settings
- Burners
  - Tilt

- SA/TA damper settings
- Turbine
  - All bleed temperatures (some were missing)
  - All bleed pressures (some were missing)
- Condensate / feed-water
  - All temperature before and after pre-heaters (some were missing)
  - All drain temperatures (some were missing)

The reader can refer to Chapter 6.3, for a full list of required measurements.

- **Mills**

The boiler should be prepared for operating with "high-firing" by using mills G-K

- **Steam Air Pre-heater**

The SAP should be able to operate and secure the mill outlet temperatures.

- **Coal sampling**

Preparations necessary for taking coal samples during the test. Optimally one sample per hour for getting an overview of the LHV/HHV variations.

- **P.F. sampling**

Taking pf. samples from the coal pipes are necessary for analyzing the fineness by sieve tests.

- **Controls**

One take-away from the *"Current Low-Load"* (see Chapter 7.1) was that the boiler drum level control as well as the RH super-heater water injection control needs to be optimized.

- **Logic changes in the Distributed Control System (DCS) during visit**

Although it has not been discussed before, it would be beneficial to have the possibility to change the logic in the DCS during the site visit and test. For example, if the experts discover that there is a particular logic, for example a limit value, or a certain control structure that prevents reaching a lower boiler load, is it possible to change the logic, while the plant is in operation? Based on the Danish experience, the normal procedure is to state clearly what is the situation, and write a "short note", and then have it approved beforehand. The DCS programmer, available at the plant, would execute the change.

- **<u>Preparations before commencing the test.</u>**

  The following preparation should be done at the unit and plant selected, prior to the test.
  - Soot blowing
  - Ashing (emptying of ash hoppers)
  - Coal mill reject box shall be emptied
  - Furnace water seal verified
  - The unit must be isolated both electrical and on the water/steam side
  - No known equipment problems

Test plan

A total of three days should be allocated for the pilot test: 1 day for preparation and 2 days for the testing.

On the day before the test, it is suggested to meet all plant personnel that will be present during the two test days. The agenda will be discussion on the test plan and to perform a risk evaluation.

Two days are envisaged for performing the tests. The first day is expected to be used for experimenting with the boiler load and settings to find the best and most stable low load. On the second day the unit shall then operate at this load in at least 8 continuous hours.

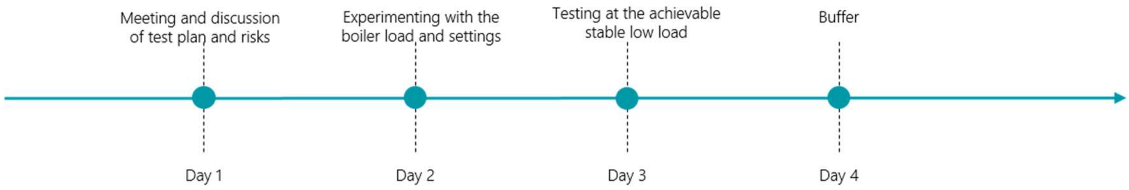


Figure 24 Draft plan for pilot in Ramagundam

- **<u>Reducing load</u>**

Oil support is required for stabilizing when reducing the load beyond the known *"current low load"* (see Chapter 7.1) and taking mills out. All operations must be done by the control room personnel and supervised by plant engineers. COWI/DEA's role is only to support, observe and assist.

- **<u>Suggested plan for 1st day tests</u>**

The following plan is only a suggestion and should be used as an input for a common final plan.

1. Bring the unit down to "current low load", 271 MW
2. Change mill setting to high-firing
3. Reduce to 4 operating mills G-K
4. Reduce load to 250 MW (mill load 72%)
5. Reduce to 235 MW (mill load 69%)

6. Reduce number of mills to 3 (H-K) (mill load 91%)
7. Reduce load gradually. The goal is 200 MW (mill load 78%)

This roadmap is probably time consuming, and the number of steps could be reduced.

During the test day both coal- and pf. samples shall be collected. If possible, the sieve analysis shall be conducted, and the data is available prior to 2nd test day.

7.2.2. The pilot

This section provides details on the initial and subsequent low-load tests carried out at Ramagundam unit 7 on two separate occasions. The initial test occurred on February 28th and March 1st, 2023, while the follow-up test took place on September 5th and 6th, 2023.

The Danish team, consisting of representatives from the Danish Energy Agency (DEA) and their consultant, COWI, supervised the planning and execution of the test. The operational responsibilities of the unit were managed by the plant staff, with oversight from officials of NTPC (National Thermal Power Corporation). Furthermore, during the initial test, a representative from BHEL (Bharat Heavy Electricals Limited), the principal OEM (Original Equipment Manufacturer), was present. The testing of the 1st low load test was split in 4 days, and the brief schedule is given below. The second low load test had a similar schedule.

Figure 25 Plan for pilot in Ramagundam

It was agreed that, during the 1st low load tests at both power plants, CEA would be present, and together with DEA and the plant operators (NTPC and KPCL) conduct the tests. In addition, a request was made to assess efficiency and NOx emissions at different load levels (55%, 50%, 45%, 40%). The second round of low-load tests were performed on September 5th and 6th, 2023, with a representative from Grid India in attendance during these tests.

Prior to the test execution, thorough discussions were held to determine the details and conditions. The following specific topics were presented and deliberated upon:

- Roles and responsibilities.
- Unit readiness assessment.
- Measurements and sampling protocols.
- Comprehensive planning considerations.
- Risk assessment procedures

These discussions aimed to ensure a clear understanding and consensus on various aspects related to the test, including the assigned roles and responsibilities, the preparedness of the unit, the methodology for measurements and sampling, detailed planning requirements, and the assessment of potential risks.

Additionally, based on the Danish experience, suggestions were given that the following personnel should be available at the power plants during the realisation of the pilot projects:

- The person in charge/responsible for the test
- Operation responsible engineer
- C&I engineer
- Combustion engineer (if such a professional is available)
- Control room personnel that will be operating the plant during the tests
- Additional personnel is required to take coal and p.f. samples during the tests (Necessary equipment for taking coal and pf. samples must be prepared)

It was suggested that, for logistic purposes, only the directly involved personnel should be present.

Development of risk assessment and preparation for the 1st low load tests

The first day of the first low load tests, the development of risk assessment and preparation for the test was discussed. During this day, the discussion was focused on experimenting with the boiler load and settings to find the best and most stable low load. The ultimate goal was to achieve 1%/min of ramp rate at lower load and the stable operation of unit at 40% of load with stepwise decrease of load and no refurbishment.

The purpose of the risk assessment is to identify potential factors that potentially pose a risk for limiting the test or tripping equipment

A number of risk assessments were proposed by Danish experts, and a summary is given in Table 7-4.

Table 7-4. The risk types, causes and mitigations discussed on the 1st day

Risk type	Risk	Causes	Mitigation
Personal injury	Injury from flame observations	Back firing can happen if furnace pressure increases beyond barometric, and observations are done through sight openings	• Use of face shields and flame-resistant clothing • Only make flame observations during stable conditions

	Injury from boiling water from furnace bottom water lock	If a furnace explosion occurs the water lock can be blown out	• No personnel allowed close to the water lock • Shielding of the surrounding area
Equipment damage	Erosion of last stage turbine blades leading to increased stresses and loss of turbine efficiency	Low RH steam temperature will increase moisture content in the turbine exhaust	• Monitor the SH and RH temperatures • Monitor condenser pressure • Monitor water level in condenser • Manually control the attemperator spray controls • Adjust firing tilting • Select "high firing" burners and mills (K) • Use soot-blowing preventive
	Turbine vibrations and displacement	The turbine will be exposed for unusual conditions which can lead to excessive vibrations and/or displacement	• Monitor the vibration and displacements by trend-curves • Adjust exhaust pressure • Close off selected turbine bleeds and preheaters
	Corrosion of Air Heaters	The fluegas temperature will drop in lower loads exposing a risk of condensing sulphur acid on the cold Air Heater	• Increase combustion air inlet temperature by operating the Steam Air Preheaters. • Increase air bypass to the mills • Only operate with one AH • Operate with low sulphur content coals
	Water/steam side corrosion	Feedwater quality can be compromised by e.g. lower deaerator pressure	• Monitor water chemistry by ph values and Conductivity • Lab analysis of water samples
Unit trip	Loss of flame and fuel oil is not working.	Combustion instability or poor flame detection can lead to boiler trip: • Feeder out of operation • Power out of operation • Oil nozzles not proven • No flame scanners signals (3/4)	• Visual flame observations to confirm stability • Reduce no of operating mills • Adjust primary air flow • Monitor NOX and CO levels • Reduce boiler steam pressure
	Extreme drum level	If the boiler drum level is "very low" or "very high" the boiler is tripped.	• Monitor the level by trend-curve • Manually adjust the control S.P. • Monitor the feedwater flow • Operate electrical BFP
	Extreme furnace pressure	If the furnace pressure is "very low" or "very high" the boiler will be tripped.	• Monitor the furnace pressure by trend-curve • Monitor and ensure stable ID fan operation

		Pressure fluctuations are likely	• Adjust the furnace pressure S.P. • Adjust O2 S.P. • Avoid waterwall soot-blowing

	Condensate and feedwater system stability	Low condensate/FW flow can lead to system instability which can result in equipment damage or unit trip	• Monitor condensate and feedwater conditions:
			  ○ Pump vibrations
			  ○ Flow rates
			  ○ Heater levels
			• Operate using the electric feedwater pumps
			• Manually operate the heater drains to control the level

In addition to the aforementioned risks, there is a number of other risks to consider:

- Mill trip
- Feeder trip
- Coal pipe fire
- Excessive SH metal temperature
- SH/RH steam temperature distribution
- Fuel Oil Burner failure
- Coal quality variation
- Low pf quality
- Insufficient pf distribution
- Insufficient PA and/or SA distribution
- Turbine gland seals failure
- Boiler circulation pump instability
- Too low steam pressure for soot-blowing
- Too low turbine BFP steam pressure

Additionally, the most important risks were discussed, and a number of discussions were held in order to achieve the goal of low load operation at 40%. A large part of discussion was related to avoiding the tripping of the unit and the number of mills needed to operate safely, and at what stages to collect the samples.

During the second low load tests, the similar preparation was followed.

Summary of the tests

The unit demonstrated, in both tests, its capability to achieve a 40% load using coal of relatively good quality. Although the ramp rates were not fully met, the unit exhibited a highly favorable response during the testing period.

During the course of the works, two primary focus areas have been identified:

1. Optimizing of control loops. The test revealed that the unit control was predominantly manual, which is suboptimal as it necessitates highly skilled control room personnel to manage and regulate the unit's operation effectively. This manual approach may lead to challenges in responding promptly to system changes and can result in inefficiencies or inaccuracies in the control process. In order to enable the unit to operate in automatic mode during low loads and ramping, it is imperative to review the following control loops as a minimum:

    a. Master unit control – fuel/load coordination.
    b. SH and RH spray temperature control.
    c. Boiler drum level control.
    d. Oxygen control and fuel/air coordination.
    e. Flue gas temperature control using SCAPH.
    f. Ramping control. Automated start-up and shut-down of mills.
    g. Mill outlet temperature control.

2. Coal dust distribution optimization. The distribution of coal dust among the individual coal pipes, from the coal mill to the burners, exhibited an unacceptable deviation, reaching up to 45%. This issue must be thoroughly investigated and addressed in order to mitigate its impact. The significant deviation observed in the coal distribution could potentially be linked to the roping phenomenon. To better understand and address this issue, a thorough investigation is highly recommended. Engaging BHEL (Bharat Heavy Electricals Limited) for a comprehensive analysis and expertise in this area could prove beneficial in identifying the root cause and implementing effective solutions. Resolving the coal distribution issue is crucial for the efficient and reliable operation of the system, as it directly affects the combustion process and overall unit performance.

A sequential approach is preferable, which involves concluding the control loops mentioned in item 1 before proceeding with the optimization of coal dust distribution in item 2. By first completing the control loops, any necessary adjustments or corrections can be made to ensure stable and reliable operation of the system. Once the control loops are established and functioning effectively, the focus can then shift to optimizing the distribution of coal dust to achieve the desired results.

It's worth noting that unlike the coal dust distribution, the dust fineness was found to be nearly in compliance with the design presumptions. This indicates that the size of coal particles meets the desired specifications, and further adjustments in this regard may not be immediately necessary.

Prioritizing the completion of control loops before fine-tuning coal dust distribution ensures a systematic and efficient approach to addressing operational issues and optimizing the performance of the unit. This step-by-step methodology helps to ensure that the necessary control measures are in place and functioning correctly before proceeding to optimize other aspects of the system's operation.

The Steam Air Preheaters (SCAPH) were not operational, and the flue gas temperature became uncontrollable. It poses challenges, particularly when low loads are expected to become a regular occurrence. In such cases, it will be necessary for the SCAPH to have the capability to raise the flue gas temperature above the sulfur dew point for avoiding corrosion in the air preheaters. By increasing the flue gas temperature beyond the sulfur dew point, the SCAPH can mitigate issues related to sulfur condensation.

For operation with wet coals, it is advisable to operate the SCAPS to improve primary air (PA) temperatures while optimizing the pulverized fuel (pf) drying process in the mills.

Maintaining the primary air (PA) bypass dampers is essential to ensure their ability to effectively close off cold PA leakages. This is particularly crucial when dealing with wet coals, as preventing cold air from bypassing the system is essential for achieving proper coal drying and combustion efficiency.

The flue gas oxygen content was deliberately high. The aim was to be confident that the secondary air distribution was controllable. To enhance efficiency, it is advisable to identify a lower level of oxygen in the flue gas, as the intentional high level was primarily intended to regulate the distribution of secondary air.

Throughout both tests, noticeable fluctuations in flame intensity levels were apparent, with intermittent flickering. These observations are likely linked to the previously mentioned problems, such as issues with pf. distribution, inadequate fineness, the absence of pf. dryout, and the potential for roping. However, the problem may also be associated with the flame scanner itself. Therefore, we recommend conducting a thorough verification process of flame scanner signals.

We recommend that the next phase of the flexibilisation process prioritize the improvement of control loops and the optimizing of distribution of coal dust. The implementation of control loops requires careful attention and extensive testing before integrating them into the DSC system. Once this phase is successfully completed, it will be necessary to conduct further tests to assess the achieved enhancements and determine if any additional upgrades are warranted.

We recommend that the upcoming phase of the flexibilisation process priorities to improving control loops and optimizing the distribution of coal dust. Implementing these control loops demands meticulous planning and thorough testing before their integration into the DSC (Distributed Control System).

To address the pulverized fuel (PF) distribution issue effectively, we recommend involving BHEL in both the planning and implementation phases. It is crucial for this process to commence promptly to ensure that the new equipment is prepared for installation during the next scheduled maintenance outage. This will help expedite the resolution of the problem.

Once this phase is successfully completed, it will be necessary to conduct further tests to assess the achieved enhancements and determine if any additional upgrades are warranted.

7.2.2.1. Planning of the tests

Each test consisted of two testing days. During the low load tests, the key indicators needed to observed and measured were efficiency/heat rate of unit at different loading, effect of low operation on NOx emissions and water consumption (55%, 50%, 45%, 40% load), CO2 emissions and other parameters and Log book.

During the second day of tests, there was a discussion on the ramp rate and a draft document where new ramp rates are proposed from CEA as follows:

- 3%/min from 70% to 100% of the maximum capacity
- 2%/min from 55% to 70% of the maximum capacity
- 1%/min from 40% to 55% of the maximum capacity.

As mentioned, the Central Electricity Authority has been present to validate the recent 2023 government regulation for achieving 40% load operation of coal fired power plants, presented at the G20 in Delhi.

As a part of planning, a plan for the low load test had to be developed for both days and sent to SRLDC (and SLDC) a day before the day of the test.

Before the test, the following actions were required by the power plant personal to be executed:

- Soot blowing
- Ashing
- Coal mills reject boxes emptied

1st test day

The plan for the 1st day test was presented to the power plant team the day before the actual test. The goal of the test was to reach 40% load in a safe and controlled manner in order not to take any risk that could eventually impede the objective. Below the plan for the 1st test day is shown for 1st and 2nd low load test.

- 28/2: Before 9:00, load reduction to 300 MW, mills “CDEF”

  5/9: Before 9:00, load stable at 375 MW, mills “BCDEF”

- 28/2: 275 MW, 1 hour, mills “CDEF”

  5/9: 270 MW, 11:15, mills “CDEF”

- 28/2: 250 MW, 1 hour, mills “CDEF”

  5/9: 230 MW, 1 hour, mills “CDEF”

- 28/2: 200 MW, 4 hours, three mills “CDE”

  5/9: 200 MW, 13:10, mills “CDEF”. 225 MW, 14:13

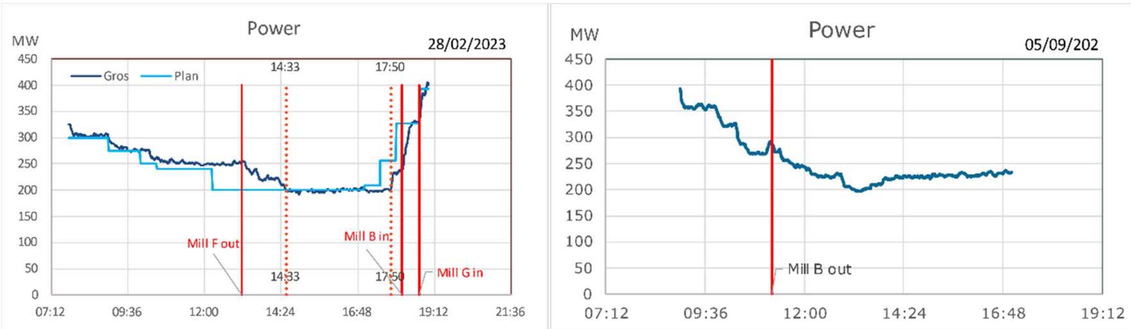


Figure 26. Load progress 1st test day.

At the first test (28/2) the unit successfully reached 200 MW (40%) at 14:33 and maintained the load for ca. 4.2 hours without any serious challenges. The second test (5/9) reached 200 MW at 13:10, however due to flame instabilities the load was increased to 225 MW at 14:13.

Samples of raw coal, coal dust and UBC was taken during the test, at:

- 28/2: 9:45, 16:30
- 5/9: between 14:00 and 16:00

Before the tests the boiler was thoroughly soot-blown, and the flame scanners were cleaned.

2nd test day

The 2nd test day was reserved for ramp rate tests.

1st low load test 1st March 2023

The objective was to demonstrate the unit’s compliance to the new ramp-rate regulative.

The load was planned to be brought down to 40% in three individual steps while demonstrating the ramp rates, likewise the ramp rates was demonstrated while increasing load.

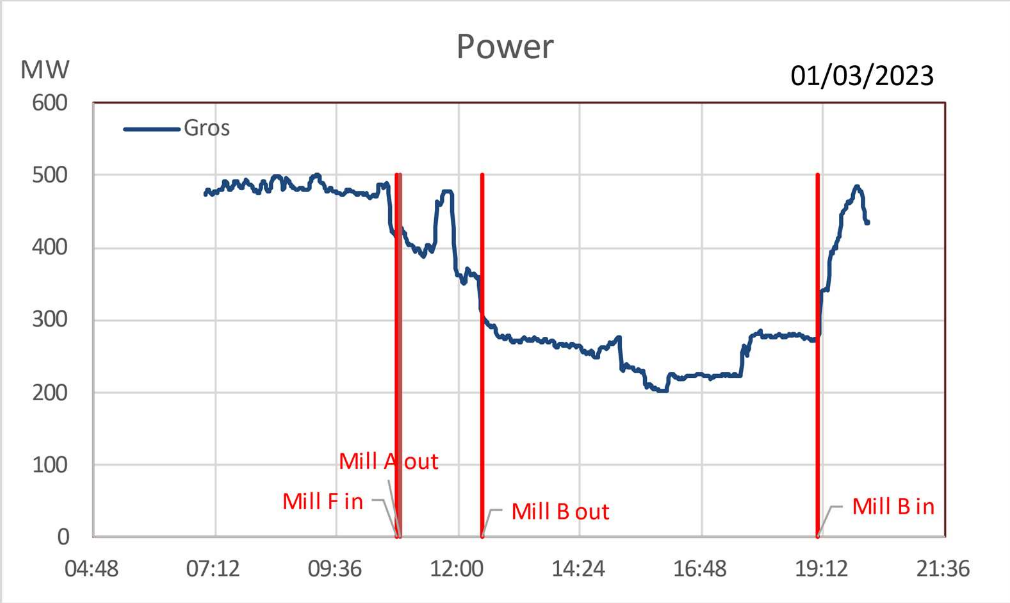


Figure 27. Load progress 2nd test day.

At 10:30 mill “K” was taken out
At 10:48 mill “F” was taken in
At 10:52 mill “A” was taken out
At 11:00 mill “H” was taken out
At 11:30 mill “H” was taken in
At 12:10 mill “H” was taken out
At 12:30 mill “B” was taken out
At 19:05 mill “B” was taken in
At 19:22 mill “H” was taken in
At 19:30 mill “A” was taken in

In lower loads, a four mill configuration “CDEF” was applied.

2nd low load test 6th September 2023

The unit load was reduced without oil guns in service down to 217 MW. At 11:45 at app. 250 MW mill “B” was taken out. Operating mills were “CDEF”.

MDBFP were kept in service along with TDBFPs.

Due to poor flame conditions the load was maintained at ca. 215 MW.

The planned ramp rate test was interrupted due to issues with flame stability, which consequently, due to inability to stabilize the flames, caused a cancellation of ramp rate testing. Instead, a decision was made to conduct experiments involving adjustments to the classifier vane setting. The angle of the classifier vane was increased to enhance pf. recirculation and fineness.

Sampling

During the stabilization periods, raw coal and pulverized coal dust were sampled. Raw coal was obtained from the feeders, and dust samples were collected from each coal pipe for each coal mill in operation. The collected dust samples were sieved into three sizes: 50, 100, 200 mesh-size. Additionally, samples of bottom and fly ash were collected and analyzed for the presence of unburnt carbon (UBC).

Coal Quality

The coal quality was analyzed by the plant's laboratory, only the proximate analysis was conducted. The result of the proximate analysis is given in tables below.

Table 7-5. Raw coal analysis.

Date	Air Dried Moisture (%)	Ash (%)	VM (%)	GCV (Kcal/Kg)
28.02.2023 09:30 HRS	6,8	39,83	26,52	3879
28.02.2023 16:30 HRS	6,35	37,67	25,65	4160

Date	Total Moisture (%)	Ash (%)	VM (%)	GCV (Kcal/Kg)
28.02.2023 09:30 HRS	11,69	37,74	25,13	3675
28.02.2023 16:30 HRS	9,2	36,54	24,88	4035

Date	Air Dried Moisture (%)	Ash (%)	VM (%)	GCV (Kcal/Kg)
05.09.2023	8,69	36,48	24,69	3738
06.09.2023	7,22	42,88	19,18	3349
06.09.2023	6,49	48,39	18,19	2943
Date	**Total Moisture (%)**	**Ash (%)**	**VM (%)**	**GCV (Kcal/Kg)**
05.09.2023	12,74	34,86	23,59	3572
06.09.2023	11,78	40,77	18,24	3185
06.09.2023	10,78	46,1	17,36	2808

The abbreviations translate to:

VM: Volatile matter

GCV: Gross Calorific Value

The fixed carbon (FC) content can be found by difference: FC = 100 – TM – VM – ASH.

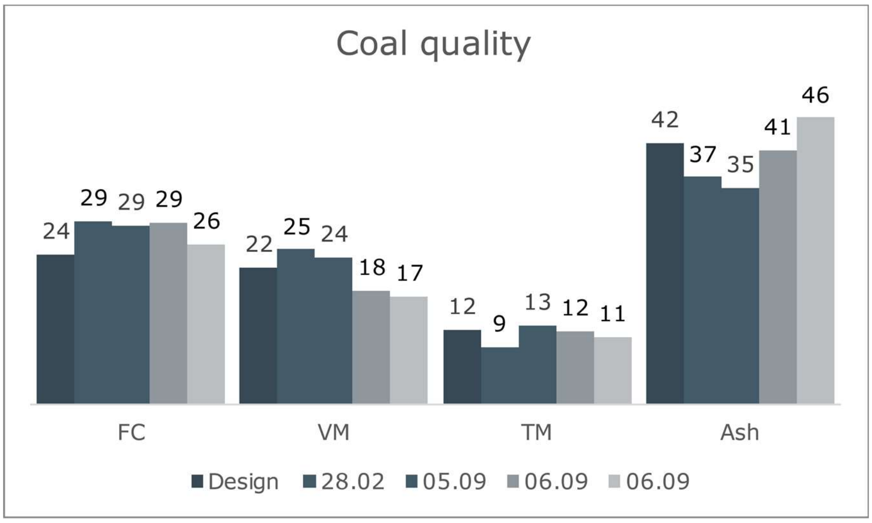


Figure 28. Coal quality during test versus design.

The Gross Calorific Value during the low load (4035 kcal/kg) was app. 19% higher than the design value 3400 kcal/kg in the first test (28/2), and 5% higher in the second test (5/9).

During the second day of the second test on September 5th, the GCV were notably low, measuring 3185 and 2808 kcal/kg. The low quality coal in the 2nd test cannot be attributed to the moisture content; instead, it is primarily due to an exceptionally high ash content.

It's important to note that these values are within the designed specifications, as per the predicted performance data, which indicated that the unit is capable of handling coals with GCV as low as 3000 kcal/kg, along with 15% moisture and 45% ash content.

7.2.2.2. Main performance data (averaged)

The main test data is show in below table. For convenience “Unit 7 Data Sheet Design” (predicted performance) for 50% load is also shown. The measurements are averaged, in the most stable timeslot available.

Table 7-6. Averaged measurements.

Time	Unit	Design 50%	28/2 2023 14:33-17:50	5/9 2023 13:09-13:35
Unit load	%	50%	39,8%	39,9%
Unit load	MW	250	199	200
Coal flow (measured)	t/h	180,2	129,3	166,4
Coal GCV/HHV (arb)	kcal/kg	3400	4035	3572
- fixed carbon	%	24	29,4	28,8
- moisture	%	12	9,2	12,4
- ash	%	42	36,5	34,9
- volatiles	%	22	24,9	24,9
Steam flow	t/h	767	618	617
Feedwater flow	t/h	767	609	614
Reheater outlet	t/h	671,3		
SH spray	t/h	72	65,62	86,06
RH spray	t/h	0	4,13	8,14
Feedwater temperature - ECO	°C	220	213,3	210,9
Live steam temperature	°C	540	541,1	537,5
RH inlet temperature	°C	312	341,3	347,4
RH outlet temperature	°C	540	537,2	522,4
O_2 APH inlet	%	3,56	9,1	8,5
O_2 APH outlet	%	-	#N/A	#N/A
FG outlet temperature APH	°C	115	117,0	96,4
FD fan-A outlet temperature	°C	28	34,9	30,3
FD fan-B outlet temperature	°C	28	34,6	30,8
PA temperature APH outlet	°C	259	252,9	237,1
SA temperature APH outlet	°C	259	252,5	259,9
Feeder C coal flow	t/h	45,1	42,4	32,0
Feeder D coal flow	t/h	45,1	43,3	44,8
Feeder E coal flow	t/h	45,1	43,7	44,8
Feeder F coal flow	t/h	0,0	0,0	44,9
PA flow to mill C	t/h	90,5	88,2	80,7
PA flow to mill D	t/h	90,5	88,8	89,7
PA flow to mill E	t/h	90,5	89,1	89,6
PA flow to mill F	t/h	-	-	89,3
PA temperature to mill C	°C	257,2	198,7	196,9
PA temperature to mill D	°C	257,2	200,4	210,3
PA temperature to mill E	°C	257,2	213,5	229,5
PA temperature to mill F	°C	-	-	218,0
PA temperature from mill C	°C	90	76,9	80,5
PA temperature from mill D	°C	90	79,6	81,6
PA temperature from mill E	°C	90	82,5	76,5
PA temperature from mill F	°C	-	-	78,4
DP mill C	mmWC	360	1,5	0,0
DP mill D	mmWC	360	-22,1	-22,1
DP mill E	mmWC	360	-22,4	-10,5
DP mill F	mmWC	-	-	450,0
Current mill C	amps	-	51,3	47,1
Current mill D	amps	-	48,3	54,0
Current mill E	amps	-	51,9	51,0
Current mill F	amps	-	-	47,6
Total air	t/h	1000	962,2	992,5
Main steam pressure	KSC (g)	171	143,5	142,0
Drum pressure	KSC (g)	174,9	149,4	147,1
RH inlet steam pressure	KSC (g)	21,4	18,0	18,3
RH outlet steam pressure	KSC (g)	20,3	17,2	17,6

Flame intensities

The flame intensities are measured between each burner level in each corner. The flame intensities are shown in figures below for first day of 1st and 2nd low load tests.

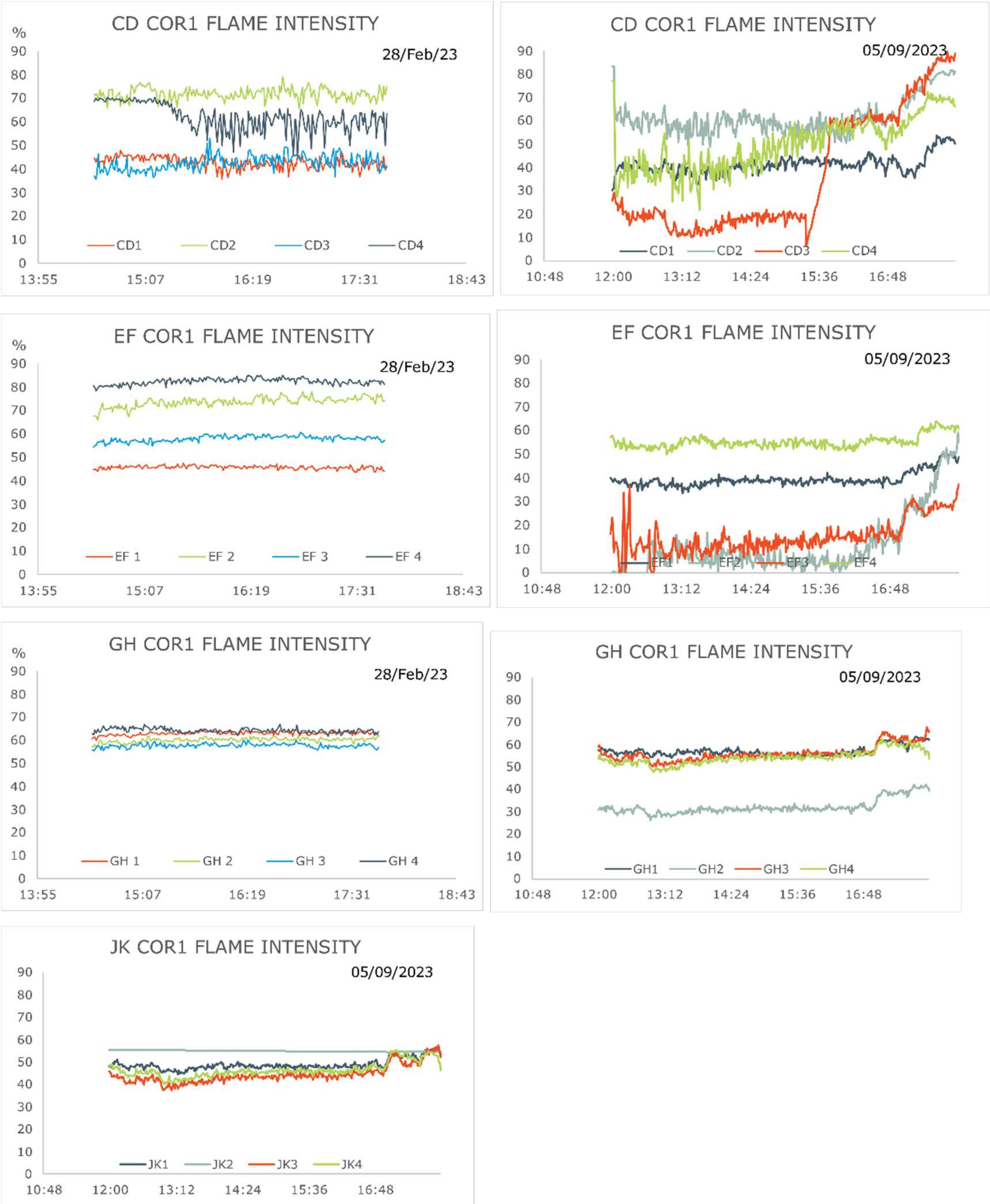


Figure 29. Flame intensities.

Coal dust sampling

The samplings from the Plant's laboratory can be found in Appendix C – Chemistry department data analysis. Sample weight distribution and averaging the samples is shown below.

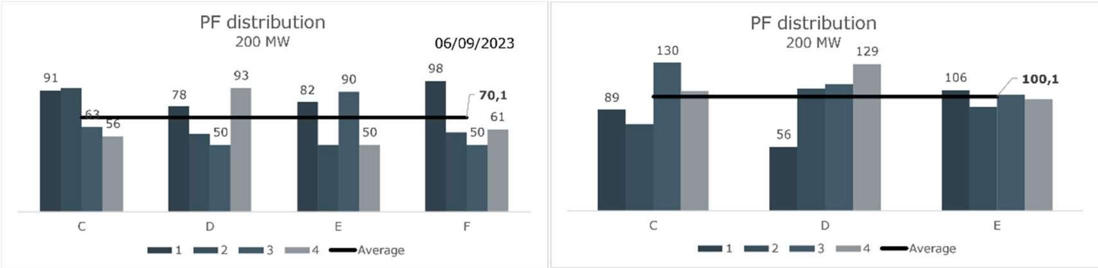


Figure 30. Sample weight distribution @200MW (28/3 and 5/9).

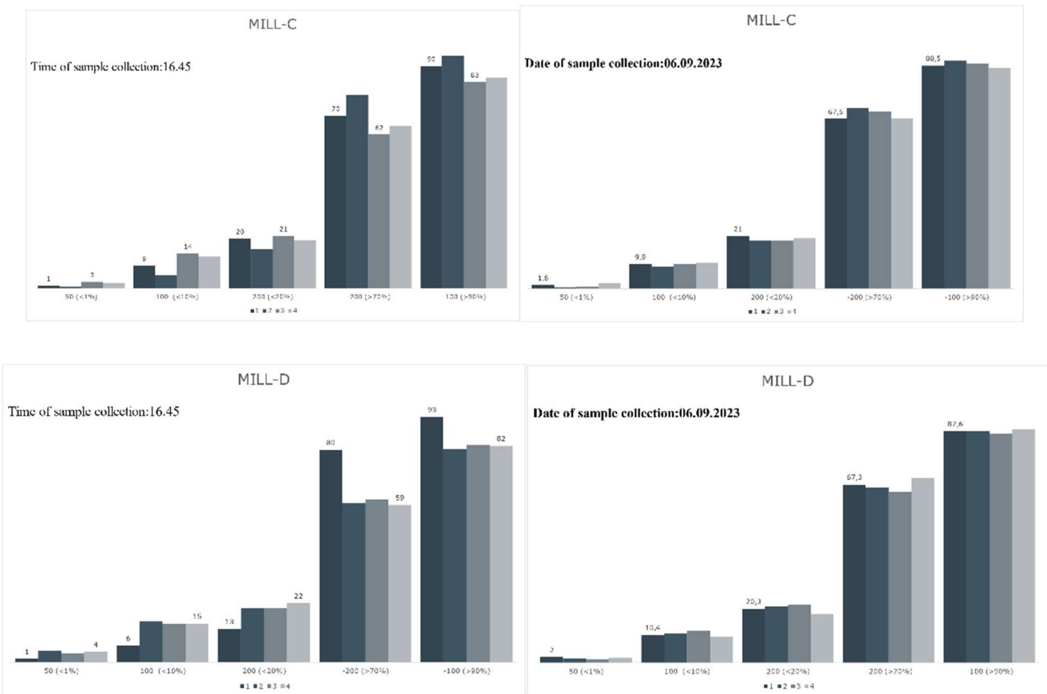
To ensure clarity regarding the quality of the samples, it is important to provide detailed descriptions and tolerances of the sampling equipment. Additionally, it may be helpful to outline any specific tolerances or acceptable variations in the sampling process to maintain consistency and accuracy in the collected samples.

For optimal results, it is recommended to collect coal dust samples using an isokinetic sampler, following the guidelines outlined in ISO 9931.

Sieve test

The data presented as the percentage of coal dust remaining on the sieve after screening can be found in Appendix C – Chemistry department data analysis.

According to design data, the requirement is 70% through a 200 mesh (75 microns), or 30% as the remainder. The coal dust sieve tests for both 1st and 2nd low load tests are given in below figures.



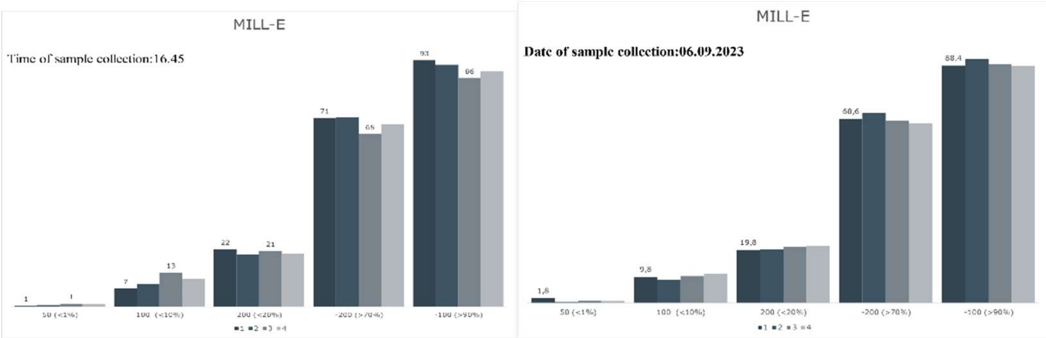


Figure 31. Coal dust sieve test at 200MW.

The samples for the 2nd test were done on the 2nd test day (6/9), hence not coordinated with the low load data for the 1st test day (5/9).

7.2.2.3. Observations during 40% low load

Coal mills

The coal mills are designed for a max. coal flow of 66.3 tons/hour while the nominal 100% flow is 63 tons/hour. The design outlet temperature is 90°C and the design fineness is 70% through a 200 mesh. The air-coal ratio is predicted to ca. 2.0 at 50% unit load and 72% mill load, based on design coals.

Mill Load

Figure below, provide the coal mill loads for the 1st test day during both 1st and 2nd low load tests.

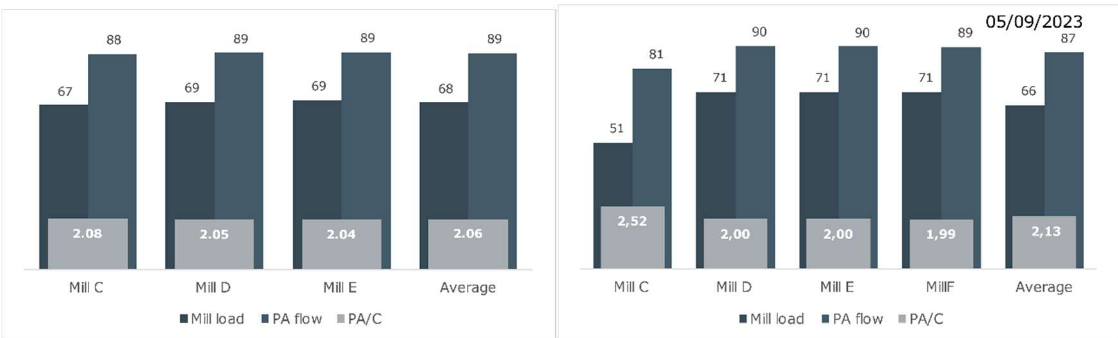


Figure 32. Coal mill loads (28-2-2023 and 05-09-2023).

1st low load test 28 February 2023

During the 40% low loads three mills "CDE" were in operation and the mass loads were in average 68.5%

The mills were loaded uniformly and the coal p.f. to PA-coal-flow ratios were quite similar. The nominal air-fuel ratio is according to the DCS curve 2.00 for 71% load. Consequently, the air-coal ratio is exceeding the nominal value, indicating an elevated air-coal ratio.

The average mill load of 68% is undesirable low as it has a negative influence on the flame stability. In a situation where only two mills would be in operation, the average mill loads would rise to approximately 65 t/h, equivalent to 102%. This would lead to an undesirably high load and an increased risk of tripping. As a result, operating with two mills at low load would only be feasible in very rare cases where high-quality coal is accessible. If operated with lower quality coals, the mill load will increase and compensate somewhat for the coal quality.

2nd low load test 5 September 2023

In the second low load test four mills were in operation with an average mass load of 66%. The mill loading was chosen not to be uniform in order to elevate the mill load for the upper mills on behalf of the lower mill.

The air-coal ratio was according to the nominal curve.

To summarize, the three mill operation would have been possible with an average mill load of 88%. This setting could potentially increase flame stability.

Mill Outlet Temperature

In figure below, mill outlet temperatures are shown for the 1st test day during both 1st and 2nd low load tests.

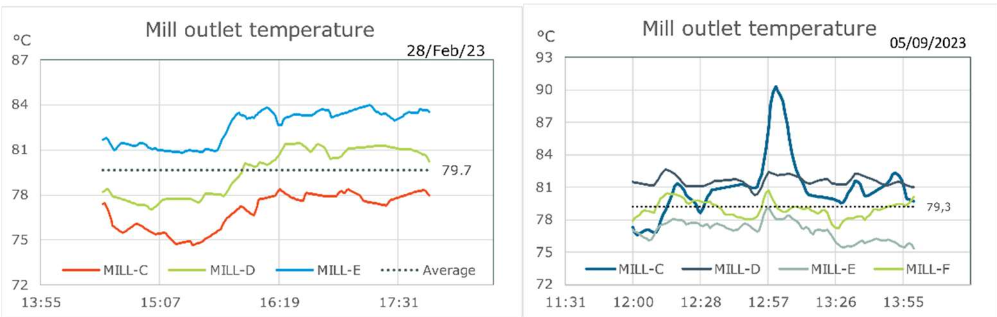


Figure 33. Mill outlet temperatures.

1st low load test 28 February 2023

An average mill outlet temperature of approximately 80°C was achieved through manual adjustment. However, this resulted in increased cold bypass and, ultimately, a higher APH outlet flue gas temperature. Conversely, a higher flue gas temperature compromises efficiency.

- The mill outlet temperature shall be as high as possible to increase boiler efficiency and pf. dry-out.

The flue gas APH outlet temperature set point must be in accordance with the sulfur acidic dew-point temperature – see below paragraph

Acid Corrosion in Air Pre-Heaters

Based on the Figure 33 above, the outlet temperature of mill "C" is app. 6°C lower than mill "E". To optimize the temperatures, they should ideally fall within a range of +/- 1°C from the average temperature.

2nd low load test 5 September 2023

From Figure 33 above, the temperature fluctuations, ranging from 77 to 90°C with a difference of 13 degrees, is considered excessive. It is suspected that this variation stems from varying inlet temperatures and uneven pf. distribution as well as elevated moisture in both coal and combustion air.

Mill Inlet Temperature

Mill inlet temperatures are shown for the 1st test day during both 1st and 2nd low load tests in below figure.

As seen in the figure, the second test, mill-C temperature experienced a rapid drop from 233 to 195°C in just 20 minutes. This occurred because the mill outlet temperature reached 90°C, triggering the controls to open the cold bypass in order to cool the inlet temperature. This situation serves as an example of a control system that should be optimized to prevent excessive temperature fluctuations.

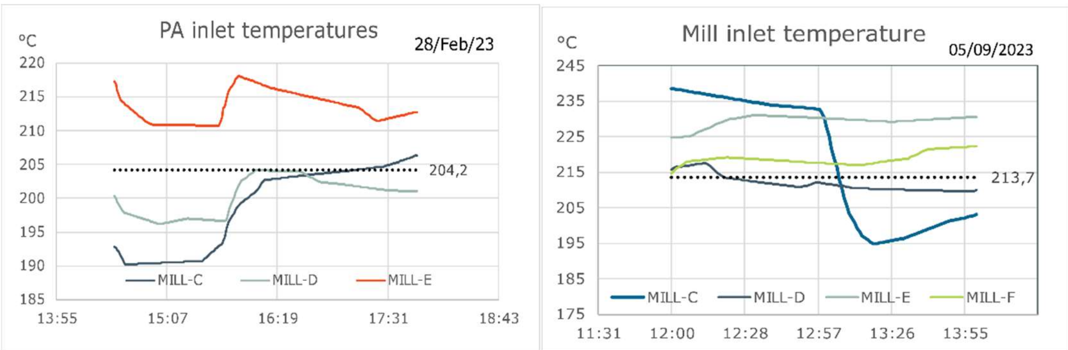


Figure 34. Mill inlet temperatures.

Both tests show a large temperature variation of 14 and 19 degrees.

Raising the mill's outlet temperature from 90 to 100°C can reduce the relative moisture in the combustion air by around 30%, leading to a notable enhancement in the drying process. Additionally, a 1% increase in coal moisture content requires an approximate 15°C higher primary air (PA) inlet temperature to attain the same degree of dryness.

- *When using moist coal during the rainy season, it may become necessary to increase both the inlet- and the outlet temperature of the mill to achieve the necessary drying effect. Elevated moisture levels in both the combustion air and coal impede the overall drying process.*

Increasing the mill temperature from 90 to 100°C comes with certain potential risks, including the risk of fire. It is advisable to seek consultation with the OEM (BHEL) before implementing such measures to ensure safety and proper guidance.

To raise the inlet temperatures effectively, it's central that the air preheater (APH) cold bypass can be fully closed. However, during the second test, there were difficulties in achieving this because the dampers were requested to close but were unable to do so due to damper leakages. This issue with damper leakages can hinder the control of inlet temperatures and impact the overall combustion process. It is suggested that this issue is addressed during the normal maintenance outage.

Feeder Speed

The feeders are designed for a capacity between 16.4 and 82 t/h. While operating in the 40% low load the average feeder load was well within the acceptable range, measuring at 52% in the first test and varying between 39% and 55% in the second test.

Differential Pressure

The mill pressure differential is designed for 386 mmWC at nominal load.

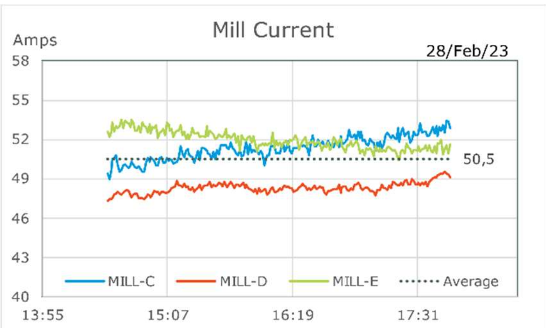
The measurements were not functioning, while mill "C" showed a differential pressure of 1.5, "D" -22.1 and mill "E" -22.4 mmWC.

- The DP measurements must be maintained and fixed.

Mill Motor

The mill motors are designed for 525 kW, 3.3 kV and 137 Amps. Only currents are available to measurements. The current for the 1st test day during both 1st and 2nd low load tests are shown in figure below.

In average the distribution is considered within the normal expected.



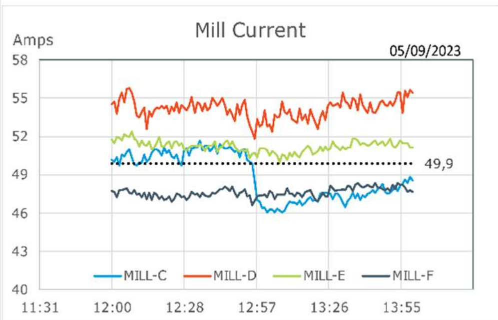


Figure 35. Mill current.

Coal Dust Distribution

The coal dust distribution for both 1st and 2nd low load tests are shown in figures below. The distribution between the individual coal pipes should optimally be within a range of app. +/- 5%.

1st low load test 28 February 2023

Mills “C” and "D" stands out with a significant deviation ranging from -30% to +45%, which has a major impact on combustion efficiency. This effect is also noticeable in the flame intensities. Mill “E” provides a coal dust distribution in line with the outlined optimal range.

2nd low load test 5 September 2023

All mills exhibit excessive distribution deviations from -46% up 28%.

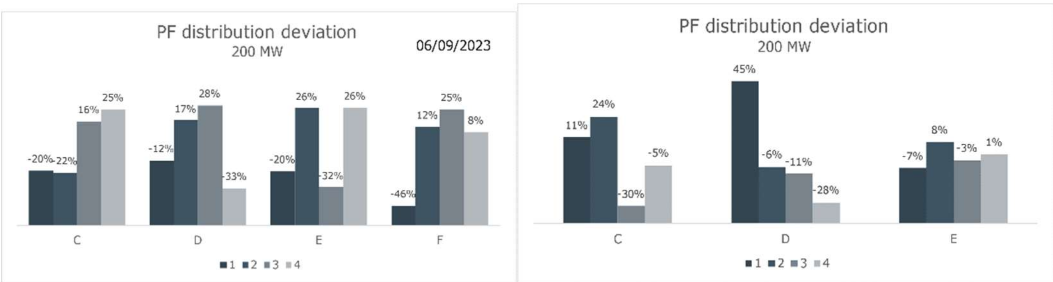


Figure 36. Mill coal dust distribution deviation.

Overall, based on the testing, the following finding should be taken into consideration:

- The pf. distribution needs to be optimized

Overview, optimization and balancing of coal dust

In the following, a summary of the coal dust optimization and balancing is given based on the finding.

Balancing the coal dust output from a coal mill is a well-known problem for thermal power plant operations. The issue primarily arises due to several factors:

1. Variability in Coal Properties: Coal quality can vary significantly, even within the same batch of coal. Differences in moisture content, particle size distribution, and calorific value can lead to uneven combustion and, consequently, uneven coal dust output.

2. Mill Wear and Tear: Over time, coal mills experience wear and tear, which can result in uneven grinding of coal. This can lead to variations in coal dust output as the mill components degrade.

3. Mill Load Fluctuations: Changes in the load on the power plant can affect the operation of coal mills. Sudden load changes can disrupt the balance of coal flow within the mill, causing fluctuations in coal dust output.

4. Classifier and Vane Settings: The settings of classifiers and vanes within the coal mill play a central role in determining the fineness and distribution of coal dust. Incorrect settings can lead to imbalances in coal flow and output.

5. Environmental Impact: Imbalanced coal dust distribution can lead to uneven combustion in the boiler, potentially causing emissions of pollutants and reduced thermal efficiency. This can result in environmental compliance issues and operational inefficiencies.

To address these issues and achieve better pf. balance, various strategies can be applied:

- Regular Maintenance: Scheduled maintenance and inspection of coal mills are crucial to detect and rectify wear and tear issues promptly.

- Coal Quality Control: Implementing stringent coal quality control measures, including coal sampling and analysis, helps ensure consistent fuel properties.

  Optimal Mill Settings: Properly configuring mill and classifiers parameters to match the coal characteristics and load conditions is essential for achieving balance.

- Load Management: Employing load-following strategies and control systems can help mitigate the impact of load fluctuations on coal dust output.

- Monitoring and Control Systems: Utilizing advanced monitoring and control systems can provide real-time data on mill performance, facilitating timely adjustments. For example, this could involve implementing online pf. flow measurement alongside real-time flow adjustments. Additionally, analyzing for residual pf. moisture can be used for adjusting the mill temperature settings.

Balancing coal dust output is vital not only for maintaining combustion efficiency but also for minimizing environmental impact and ensuring the overall reliability of thermal power plants.

Adjustable orifices or valves can be valuable components in addressing the issue of balancing coal dust output from coal mills in thermal power plants.

- Flow Control: The equipment can be strategically placed within the coal dust distribution system to regulate the flow of coal dust from the mill to various burners. While automatic control becomes a viable option once the system is thoroughly proven, it is prudent from a safety perspective to initially rely on manual control.

- Fine-Tuning: The equipment allows for fine-tuning of the coal dust flow. By controlling the flow rate to individual burners, the combustion can be optimized reducing the risk of incomplete combustion or high emissions.

- Monitoring and Feedback: Advanced control systems can be equipped with monitoring and feedback mechanisms that continuously assess the performance of adjustable orifices and valves. This data can be used to make real-time adjustments, ensuring optimal coal dust distribution.

Maintenance and Reliability: Regular maintenance and inspection of these components are critical to ensure their reliability. Properly maintained adjustable orifices and valves can continue to function effectively in maintaining coal dust balance.

The analysis indicates a possible problem with the “roping” phenomenon, which needs to be analyzed in more details.

> *Roping is a phenomenon that occurs in coal dust pipes where the coal particles adhere to the pipe walls and accumulate over time, reducing the cross-sectional area of the pipe and causing flow disturbances. As a result, the velocity of the coal particles increases, causing erosion of the pipe wall and potentially leading to blockages and reduced system efficiency.*
>
> *The root cause of roping is typically related to the properties of the coal itself, such as its size distribution, moisture content, and chemical composition. For example, coal with a high moisture content can stick together and form clumps, which can then coalesce into a rope-like structure under certain conditions. Additionally, changes in the velocity or direction of the gas flow within the pipe can also contribute to the development of roping.*
>
> *Roping can have significant negative impacts on the performance of a power plant, such as reduced coal flow and combustion efficiency, increased pressure drop and power consumption, and even the risk of pipe blockages and equipment damage.*

To mitigate the "roping" phenomenon in coal pipes, several measures can be implemented which are very much in line with the measures to mitigate pf. distribution. Both issues are interconnected in the context of coal handling and combustion systems in thermal power plants. Addressing one issue often involves considerations and strategies that can impact the other, making it important to approach them together for optimal performance.

Coal Dust Fineness

The fineness should, according to design, be more than 70% for a 200 mesh (75 microns) which not always achieved for all mills. The coal dust fineness deviations for both 1st and 2nd low load tests are shown in figures below.

In general, based on both tests, it appears that the fineness of the pf. is lower during the second test, however it's noteworthy that the deviation is also lower in this test.

1st low load test 28 February 2023

Mill “D” has the lowest average of 65%, and a deviation ranging from -10% to +23%. Mill “E” performs better both regarding distribution and fineness. To conclude, mill “D” is the most problematic, but also mill “C” needs attention. The fineness should optimally be better.

2nd low load test 5 September 2023

The total averaged fineness is 68% (-200) with a deviation from 67 to 69%.

In general, if the pf. is too coarse, it may not burn completely within the combustion chamber. Conversely, excessive fine pf. can suspend in the air (flue gas) for extended periods without burning efficiently. This condition can lead to a phenomenon known as "fly ash carryover," where fine particles are carried out of the boiler and into the flue gas, potentially causing fouling and corrosion in downstream equipment such as air heaters and electrostatic precipitators.

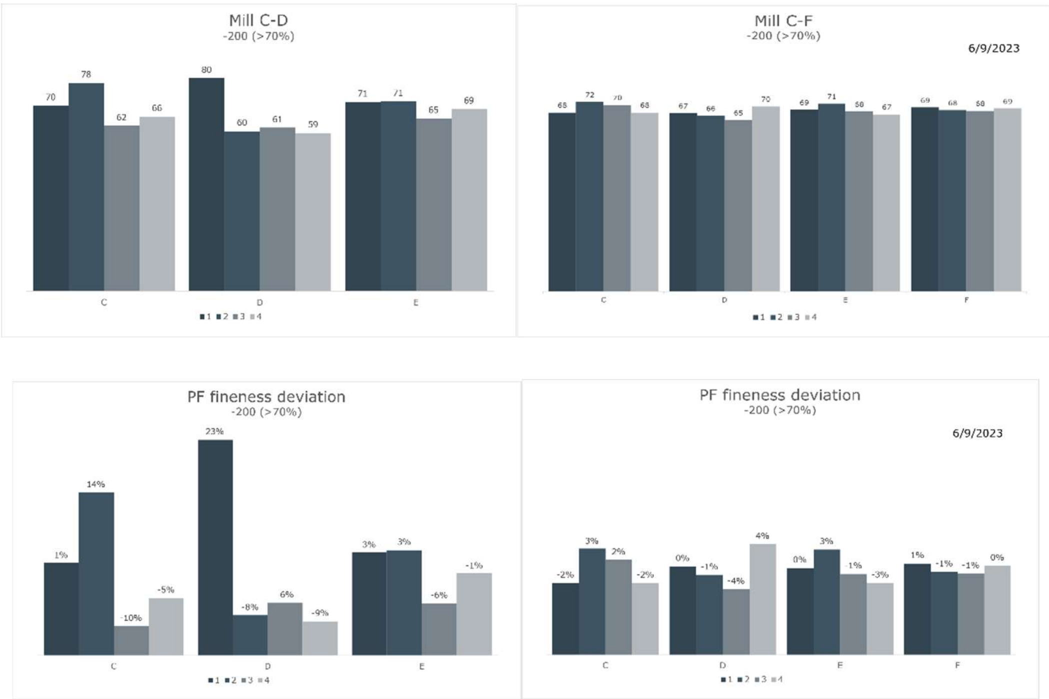


Figure 37. Mill coal dust fineness (-200 (>70%)) deviation.

Burner flame detection

In general, to classify a flame as "acceptable", it is expected that the flame intensity level remains consistently above 40%, and the flame signal should exhibit stability without flickering.

The significant variation in intensity levels at same burner level is unacceptably high. Several potential factors may contribute to this issue. While the quality and distribution of pf. are one aspect, it's also essential to emphasize the quality of the scanners as they could be a contributing factor. Therefore, we recommend conducting a verification of flame scanner signals as part of the troubleshooting process.

- Verify flame scanner signals.

The verification process should commence with visual inspections and proceed to equipment maintenance and calibration. In some cases, it may become necessary to replace the existing scanners with newer and more modern ones to address any issues with flame signal variability effectively.

In Denmark, all coal-fired units, whether retrofitted from heavy fuel oil or newly constructed, were fitted with a "LAND" make flame scanner for each burner. During retrofitting to Low-NOx burners, it became necessary to readjust the flame scanners to accurately monitor the new optimal ignition zone. LAND Instruments International, now a part of AMETEK Land, specializes in temperature measurement and combustion monitoring equipment, including infrared thermometers, pyrometers, and flame scanners. Web page: https://www.ametek-land.com/

Furthermore, it's imperative to correctly position the flame scanners to avoid detecting flame signals from neighboring burners. When considering the optimal scanner solution for Ramagundam, it's essential not to rely solely on Danish experiences due to significant disparities in coal quality and burner technology. The recommended approach is to initially seek guidance from BHEL and, if needed, consult with international suppliers for additional insights.

1st low load test 28 February 2023

The measurements from the flame scanners appear reliable, and the overall intensity level is satisfactory above 40%. However, there are occasional instances of flickering that have been noted.

The flame intensity shown in figure below reveal a significant difference of 41%-point in level EF, ranging from 44 to 85, which is then reduced to a variance of 11%-point in level GH.

The intensity observed in levels CD and EF signifies the well-known issues related to the coal dust fineness and distribution from mills "C" and "D". The intensity level for CD3 was as low as 43% in average, with a min. of 36 and max of 53, which identifies as flickering. CD4 showed the same flickering behavior within a range of 24 from 46 to 70.

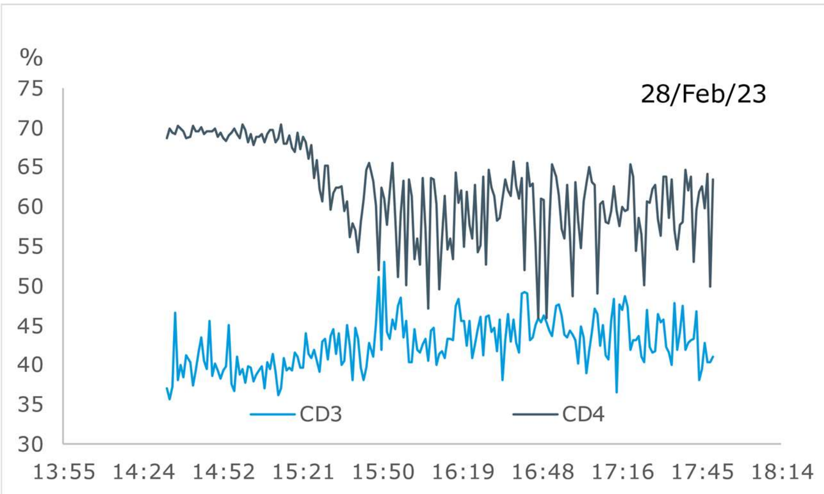


Figure 38. Intensity flickering.

2nd low load test 5 September 2023

The intensity levels vary widely, spanning approximately from 10% to 70% with a notably increase in flickering. The large deviation is most likely related to aforementioned problems (distribution and fineness). Moreover, roping is more prone to occur when dealing with wet coals.

Combustion

According to the design data, the UBC should be below 2%.

1st low load test 28-2-2023

During the first test, 2.37% and 0.25% were measured for bottom ash and fly ash respectively. This excess it's not significantly high nor concerning.

2nd low load test 5-9-2023

The tests showed a bottom ash UBC in the range from 1.47% to 2.97%, and a fly ash UBC level ranging from 0.45% to 0.67% i.e. not alarming levels.

Oxygen

The general oxygen level is deliberately increased to ensure that the Secondary (SA) dampers remain operational and maintain a good and controllable distribution.

However the boiler efficiency is compromised by a high O_2, i.e. the following findings should be noted:

- To ensure efficiency and accommodate SA dampers, the O_2 shall be adjusted appropriately.

The relatively high O_2 set point has a positive impact on the RH outlet temperature, as it promotes convective over radiative heat transfer.

A high O_2 level is generally undesirable because it promotes the generation of thermal NOx. Therefore, minimizing excess O_2 levels is fundamental for reducing NOx emissions. By reducing the O_2 level and controlling NOx emissions, the combustion process can operate more efficiently and safely while reducing its environmental impact. Nonetheless, it is important to note that the primary source of NOx in coal combustion is the fuel generated NO_X, which generally accounts for 60-80% of the total NO_X emissions.

1st low load test 28-2-2023

The O_2 percent was manually increased to ca. 9% before the APH.

The measured NO_X level was 425 mg/Nm3, with a variation from 400 to 444 mg/Nm3. The CO level was very low at 4 mg/Nm3. Both NO_X and CO are within acceptable levels.

2nd low load test 5-9-2023

The average O_2 level was ca. 8.5% before the APH. The NO_X level was ca. 415 mg/Nm3. CO measurement is not available as the CO measurement was not working properly.

Fans

The ID fan is designed with a VFD drive while both FD and PA fans are designed with constant speed.

When fans are operated in variable loads and are exposed to more challenging control requirements, variable frequency drive (VFD) control is generally considered to be a preferable option compared to blade pitch or damper control. Variable frequency drives allow for precise control of the fan speed by varying the frequency of the electrical supply to the motor. This allows the fan to operate at a range of speeds and maintain a consistent airflow, even when the load on the fan changes. In contrast, blade pitch control involves adjusting the angle of the fan blades to control the airflow, which can be less precise and more difficult to manage. Similarly, damper control involves adjusting the position of dampers in the fan system to control the airflow, which can result in inefficiencies and increased energy consumption. Overall, VFD control is generally considered to be a more efficient and effective way of controlling fans in variable load conditions and can help to reduce energy consumption and maintenance costs.

1st low load test 28-2-2023

The fans (FD, PA, and ID) were operating without any significant issues during the 40% low load. The two ID fans were operating in parallel at approximately 20% and 15% (395/302 kW) load, while the FD operated at approximately 7-11% load (348kW/245kW), and the PA fans operated at 22-31% load (544kW/768kW).

2nd low load test 5-9-2023

The ID fans were operating in parallel at ca. 18% load (372/363 kW). The FD fans were operating at very low load at 10% and 8% (331/248 kW). And the PA fans were operated at 30 to 34% (750/821 kW).

To summarize:

- The fan loads, for specially the FD fans, are very low. A possible solution to mitigate this, is to operate only one line, e.g. PA-A and FD-A, while stopping PA-B and FD-B. Because of the cross-over lines between line A and B this will not influence the cooling of flue gasses.

Boiler Drum Level

Boiler drum level control stability is critical for stable load control in a boiler system. The level of water in the boiler drum needs to be maintained within a narrow range to ensure efficient and safe operation of the boiler. Unstable boiler drum level control can also affect the overall stability of the system and make it difficult to maintain a stable load. Therefore, ensuring stable and reliable boiler drum level control is essential for achieving stable load control and safe and efficient operation of the boiler system. The drum levels for both 1st and 2nd low load tests are shown in figure below.

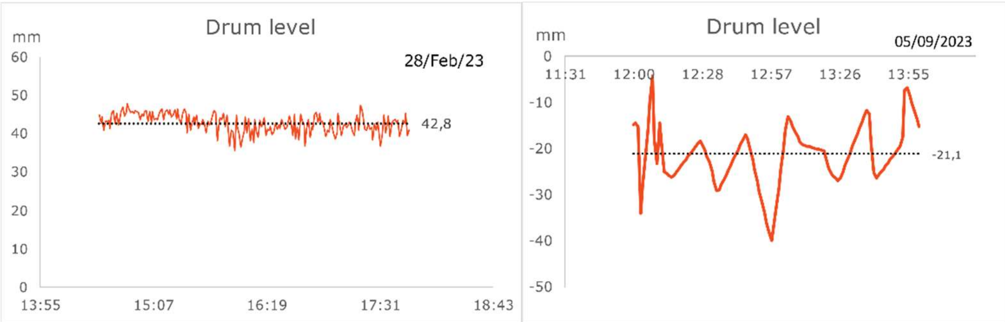


Figure 39. Drum Level.

When comparing the two tests, it's evident that the level control is not performing satisfactorily. Ideally, the average level should remain consistent at the same level during both low load tests.

1st low load test 28-2-2023

The boiler drum level was manually controlled and didn't pose noteworthy challenges while operating in stable low load.

After the stable low load operation, the load was increased in a high ramp rate, while the drum level control was still not compromised.

2nd low load test 5-9-2023

The level fluctuated between -4 and -40 mm in the two hours between 12 and 14. The level control can be improved significantly, which will stabilize load controls. Since the level is fluctuating, the FW control valve for the drum level control is also fluctuating, which will influence the pressure for the water injection to the attemperators. This will create fluctuating stem temperature.

To summarize:

> It is necessary to modify the drum level control system to ensure stable and reliable control during low-load as well as high-load conditions. COWI can supply a, stable and easy to implement drum level control, as it is used on Danish power-plants.

Acid Corrosion in Air Pre-Heaters

Short-term operation below the acid dew point does not pose a significant risk to APHs. However, sustained operation below the acid dew point should be avoided in order to prevent corrosion.

The exit flue gas temperatures from APHs were quite low, around 117°C in the 1st test and 96°C in the 2nd test. Due to the absence of information regarding sulfur content in the coal analysis, conducting a thorough analysis of corrosion risk is not possible. However, assuming a standard sulfur content of 0.45%, an estimation of the dewpoint temperature at around 110°C can be made. The measurement of the cold FD combustion air temperatures is ca. 36°C. The Danish approach involves determining the APH plate temperature by averaging the gas and air temperatures, resulting in a temperature of 76°C in this particular case. Therefore, the APH plate temperatures are significantly lower than the sulfur dewpoint temperature, indicating a high potential for acidic corrosion in the APH's cold end.

Unfortunately, the Steam Air Preheaters (SCAPH) installed in the unit were not operational during the testing period. In a situation with operational SCAPH's, they could have raised the flue gas temperatures, resulting in APH plate temperatures above the sulfur dewpoint temperature. This, in turn, would have helped mitigate the increased risk of corrosion.

- Perform necessary maintenance of the SCAPH's to mitigate the corrosion risk of the APH.

Operating the SCAPHs during the wet monsoon season (as observed in the 2nd test) will lead to an increase in the primary air (PA) inlet temperature to the coal mills. This, in turn, will improve the drying process within the mills and contribute to a more stable combustion process.

General Comments

The operation of both spray and burner tilt resulted in reaching the set point temperatures for both SH and RH due to the elevated O_2 level. To decrease the SH/RH spray, the O_2 level can be reduced while keeping the SA damper control in place. However, it's important to note that a decrease in SH/RH temperature will only become problematic if the turbine exhaust wetness level exceeds the critical level, which can be obtained from the OEM, which is typically around 12-13%. If the SH/RH temperatures drops below acceptable levels, the temperatures can be raised by selecting a higher firing by choosing a mill combination which includes mill "F".

It's important to consider that operating at a high firing rate is generally not recommended, as it can lead to lower furnace residence time, potentially causing increased unburned carbon (UBC) and slagging issues. However, during low-load operation, the residence time increases, and the furnace exit flue gas temperature decreases. Given these factors, using high firing may indeed be an acceptable solution in certain circumstances.

Reducing the O_2 level will also decrease the temperature of the flue gas, which will increase the potential for corrosion in the APHs.

Furthermore, several of the controls were handled manually by the control room operators which is not an ideal situation as it requires very skilled personnel.

Additionally, reviewing the following control loops is essential to enable the unit to operate in automatic mode during low loads and ramping. The following controls should be considered for reviewing:

- Master unit control – fuel/load coordination.
- SH and RH spray temperature control.
- Boiler drum level control.
- Oxygen control and fuel/air coordination.
- Flue gas temperature control using SCAPH.
- Mill loading
- Mill stop and start.
- Mill outlet temperature.
- Ramping control. Automated start-up and shut-down of mills.

Finally, during both tests, it was observed that the pulverized fuel (pf.) distribution was not meeting the required standards. Unfortunately, the unit lacks any mechanism to control this challenge, which is considered a fundamental factor for achieving stable operation at lower loads.

7.2.2.4. Ramp Rate Test – 2nd day of 1st low load tests

On the second day of testing, the ramp rate tests were conducted with the overall objective of demonstrating the unit's capability to meet the new standards.

The unit load was successfully reduced to ca. 200 MW (40%) over a series of individual steps. The low load was maintained for a short time where after the load was ramped up in three steps.

Before the test, the boiler heating surfaces were soot-blown, while during the testing process, the raw coal and coal dust samples were collected.

Downward High-Load Ramp Rate

The ramp rate between 100% and 70% (350 MW) were conducted in two steps by reducing mills loads.

1st step was conducted by reducing mill loads on 6 running mills “ABCDEH”. Hereafter the load was stabilized at ca. 400 MW while mill “A” was taking out and mill loads increased appropriately. The load was increased again to ca. 475 MW to instigate a longer power step down to ca. 350 MW. The 2nd ramp was conducted by reducing mill load on the 5 “BCDEH” mills.

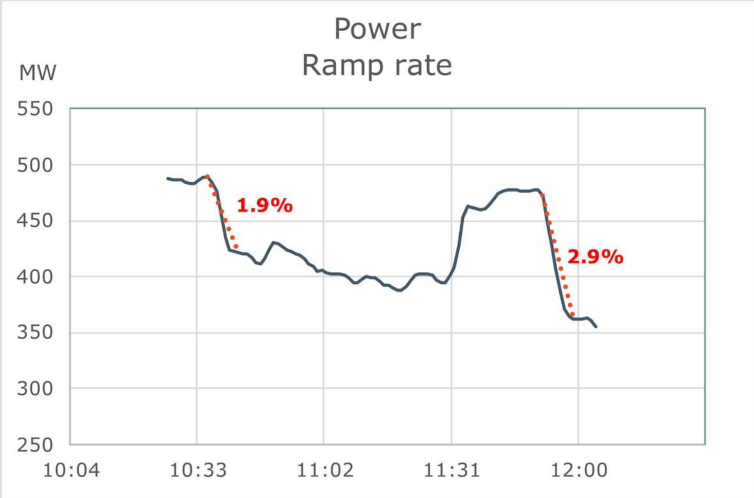


Figure 40. Obtained downward ramp rates in high load.

The ramp rate obtained in the 1st step was ca. 1.9%, while the 2nd step was performed with a 2.9% ramp rate.

Operating all six mills while attempting to reduce the load to 350 MW during the first step would lead to a minimum average mill load reduction of 50%, making it impractical. However, in the second step, with one mill less in operation, the average mill load decreased from approximately 81% to 64%.

To summarize, for more feasible ramping in the upper low range, from 100% to 70%, it is advisable to operate with only five mills. This approach will ensure stable operation throughout the full load range.

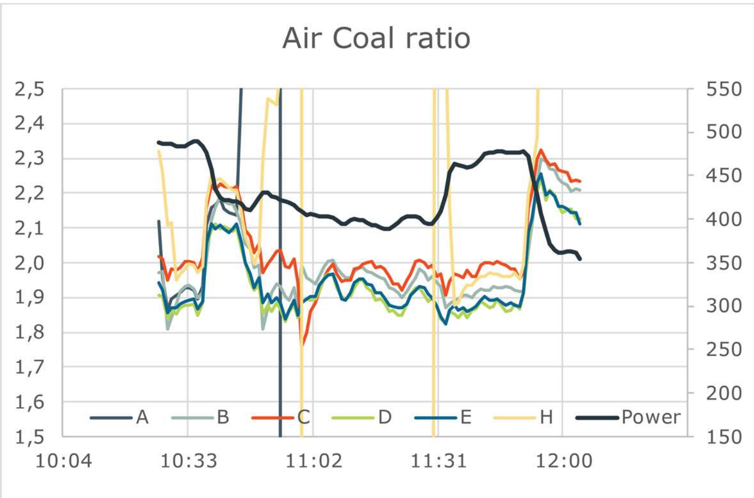


Figure 41. Coal-air ratio during high-range ramping.

During the ramping process, the mills encountered an unusual occurrence where the air-coal ratio significantly decreased, contrary to the expected behavior. Typically, during ramping down, the normal air-coal ratio curve would show an increase. This behavior can be attributed to the manual control of both feeders and PA flows.

To summarize, maintaining correct air/coal ratios during ramping is fundamental for maintaining stable flames. To achieve this, it is important to ensure smooth feeder flow control and maintain consistent mill load. Additionally, optimizing the PA flow control for ramping and improving the feeder flow control will improve the smoothness of control throughout the process. Hence, the following findings should be considered:

- The PA flow control needs to be optimized for ramping.
- The feeder flow control must be optimized for more smooth control.

Downward Mid-Load Ramp Rate

To achieve the next ramp rate in the mid load range, going from 350 to 275 MW, the approach was to remove mill "B." This resulted in an average ramp rate of approximately 2.2%, with a maximum rate of 4.3%. However, removing mill "B" alone was only able to decrease the load to approximately 300 MW. The remaining 25 MW reduction was accomplished by reducing the load on mill "F."

The applied manual load control highlights the importance of implementing automatic and optimized load controls. To achieve more efficient and reliable load control, the system should be capable of automatically taking mills in and out of operation and reducing their load without any manual interference. This automation should be driven solely by a load set-point, ensuring smoother and more precise load adjustments without the need for manual intervention. Such automatic load controls can improve the overall stability and performance of the system.

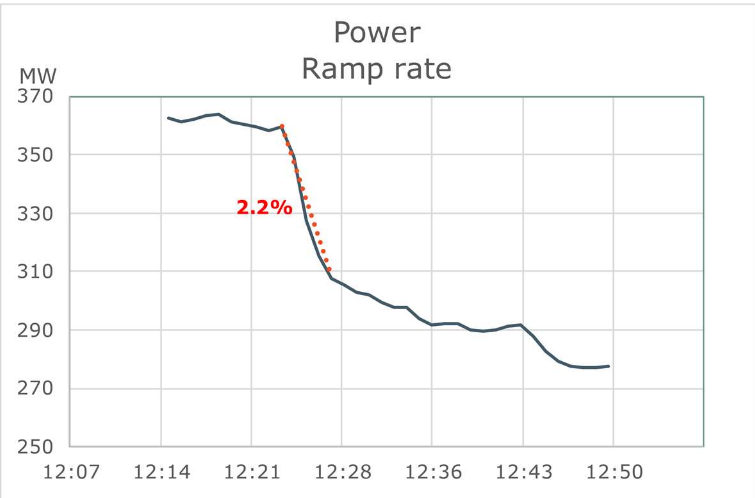


Figure 42. Obtained downward ramp rates in mid load.

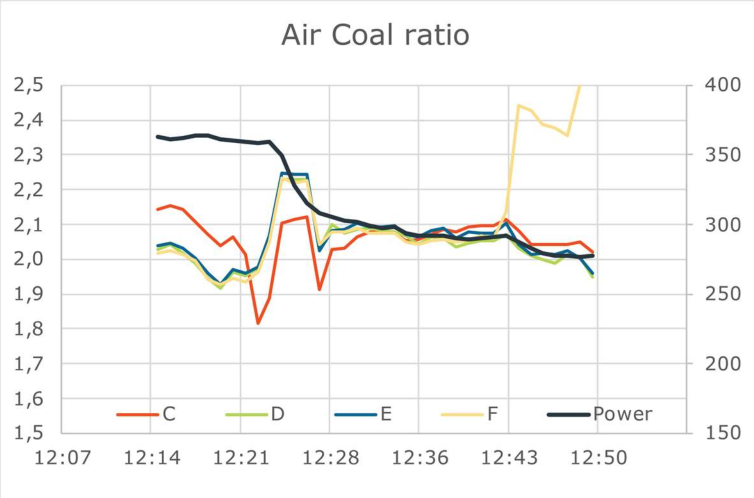


Figure 43. Coal-air ratio during mid-range ramping.

As seen during high-range ramping, the coal-air ratio was very unstable.

When addressing the dynamics of the air-coal ratio, it's essential to acknowledge that there is always a time lag between two measurements: the feeder coal flow and the PA (Primary Air) flow, as well as the actual ratio out of the mill.

Downward Low-Load Ramp Rate

To achieve the desired ramp rate of 1% in the low load range, the mill loads were reduced. The primary portion of the load reduction was accomplished by reducing the load on mill "F," which supplied the topmost active burner level. The reduction process took place in two steps, as follows. The first step decreased the load from approximately 275 to 230 MW, and the second step further reduced the load from 230 to 210 MW. The average ramp rate achieved during this process was approximately 1.1%.

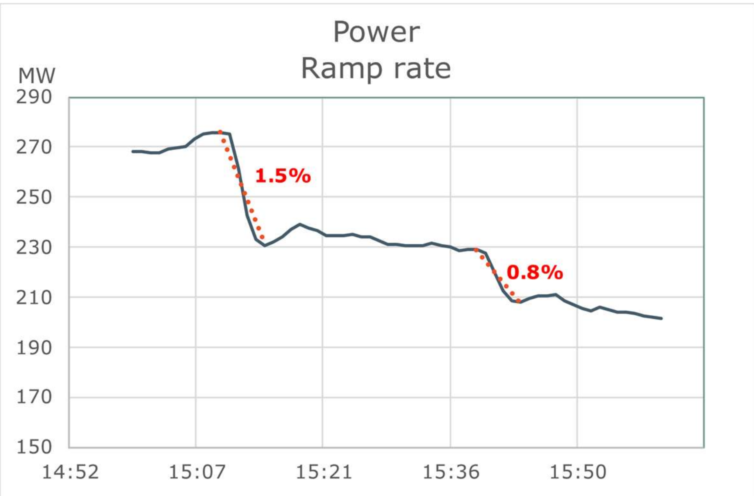


Figure 44. Obtained downward ramp rates in low load.

Mill “F” was in first step reduced to ca. 31% load and in second step to ca. 19% load, while the remaining mills maintained a load range between 60 and 71%.

It is not recommended to run mills at loads lower than 50% as it can result in unstable conditions for both the burners/flame and the mill itself.

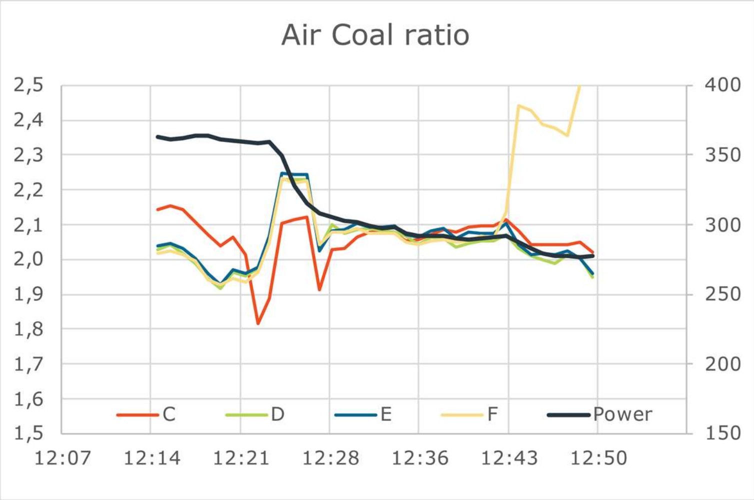


Figure 45. Coal-air ratio during low-range ramping.

Upward Low-Load Ramp Rate

At 17:35, the initial upward ramping began by raising the mill "F" load from approximately 20% to 70%. The load increase occurred in two stages, with the first stage having a steeper ramp rate of approximately 1.7%, followed by the second stage with a ramp rate of approximately 1%. The reason for the interruption of the first stage and the prolonged ramping is unclear. One possible explanation could involve pressure corrections or automatic load adjustments as alternatives.

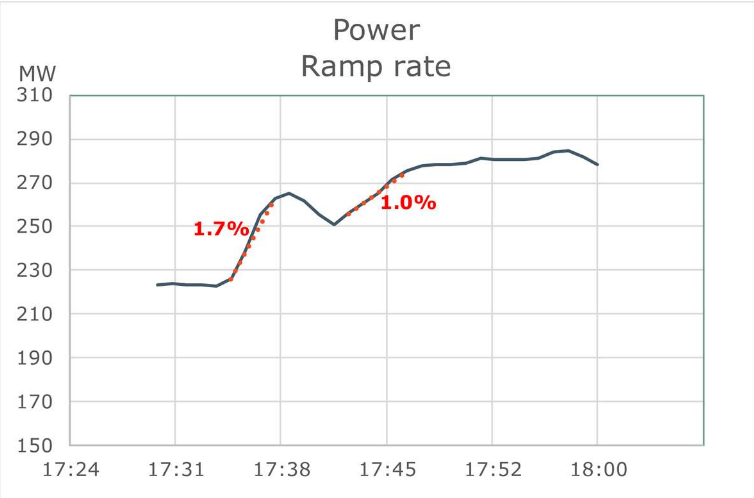


Figure 46. Obtained upward ramp rates in low load.

Upward Mid-Load Ramp Rate

The mid load range from 275 to 350 MW ramp rate was achieved by taking mill "B" back into operation. The obtained ramp rate was in average ca. 2.6%, well above the required 2%.

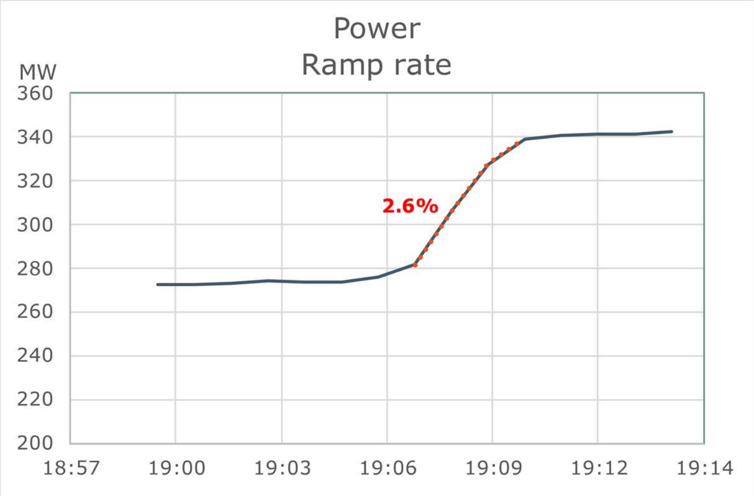


Figure 47. Obtained upward ramp rates in mid load.

Upward High-Load Ramp Rate

The high load ramping started at 19:15 with mill "H" put into operation. The 1st ramp rate from 350 to 390 MW was in average 3.2%. The second ramp was initiated by putting mill "A" into operation at 19:30 showed a ramp rate of ca. 2.6%.

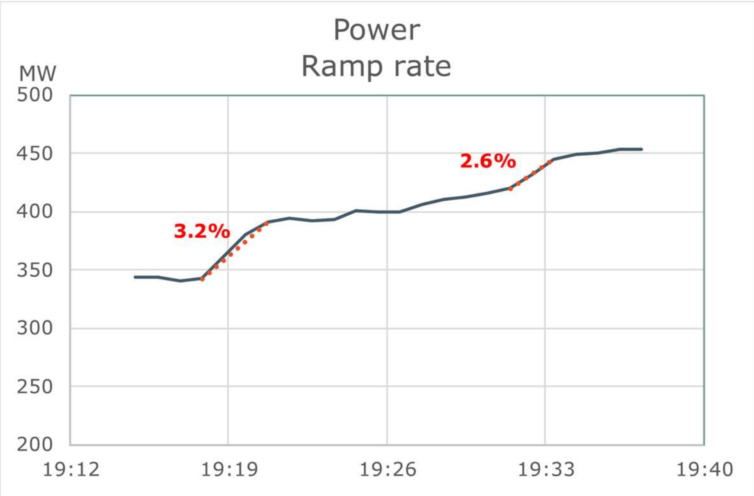


Figure 48. Obtained upward ramp rates in high load.

General Observations During Ramping

The ability of the coal mill to execute the necessary load changes plays a critical role in governing the ramping process. According to the tests, the mills and other equipment can handle the required tasks, but the control loops are not adequately developed to efficiently regulate and coordinate the ramping process.

Currently, the ramping process relies on a manual load control system where control room operators are responsible for adjusting and regulating the load, fuel, and air parameters. However, this manual approach may lead to challenges as operators may not always be able to respond quickly or accurately enough to sudden system changes. Consequently, this can result in inconsistencies, delays, or errors in load adjustments, as evident from the incidents mentioned.

On the other hand, an automated control system utilizes advanced algorithms and sensors to continuously monitor and adjust relevant parameters in real-time. This automated system can swiftly and precisely respond to load variations, optimizing the combustion process and maintaining stable operation. By implementing automated control, the overall performance and reliability of the unit can be significantly enhanced. This includes minimizing load fluctuations, reducing delays, and improving operational efficiency during ramping operations.

Generally, ramping is achieved by two mechanisms: 1) by changing mill loading, and 2) by taking mill(s) in/out of operation. To acquire a more comprehensive understanding of the advantages and disadvantages of these two approaches, it is essential to conduct a systematic testing campaign.

The following findings should be noted to improve the performance of ramp rates.

Both burner tilt and SH/RH spray injection was in operation during all operation.

- The SH and RH outlet temperatures were fluctuating and not in control, as shown in below figure.

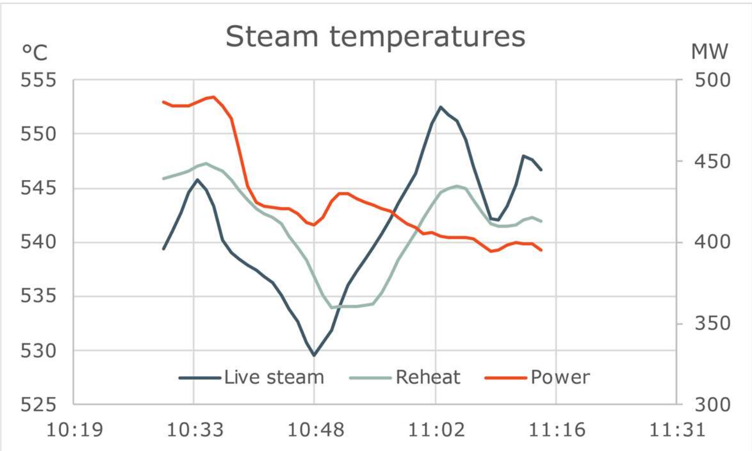


Figure 49. SH and RH temperature variation during ramping.

- To optimize ramping control, it will be beneficial to coordinate the ramping rates of mills and feeders. Specifically, all mills and feeders should be exposed to the same ramp rates. This approach should optimally be validated through more testing.

- During ramping, it is optimal to have the PA (primary air) flow control in automatic mode rather than manual, as was the case during the said tests.

- The stability of the drum level was compromised during the ramping process as seen in figure below. To resolve this issue, it is recommended to optimize the level control system. Additionally, when operating at lower loads, there is a possibility that the boiler feedwater pump (BFP) may enter a regime where it becomes necessary to open the recirculation valve. However, it should be noted that this action can further destabilize the controls.

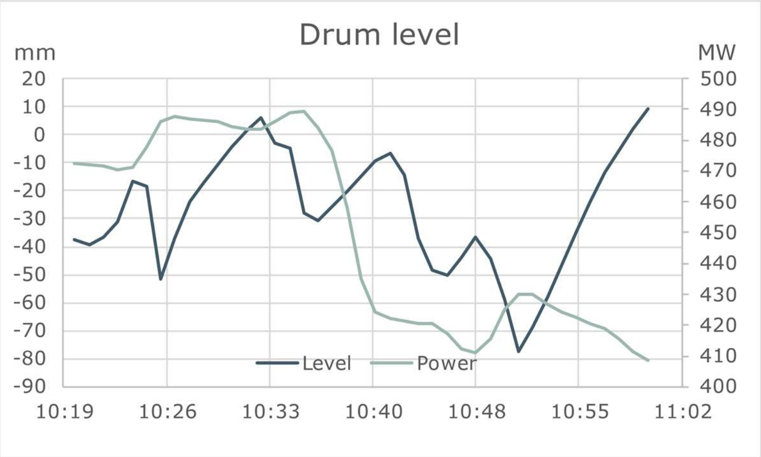


Figure 50. Drum level variation during ramping.

- Furnace pressure is not controlled sufficiently. The controls of SA pressure and furnace pressure must be decoupled and optimized to remove oscillations which can be seen in below figure.

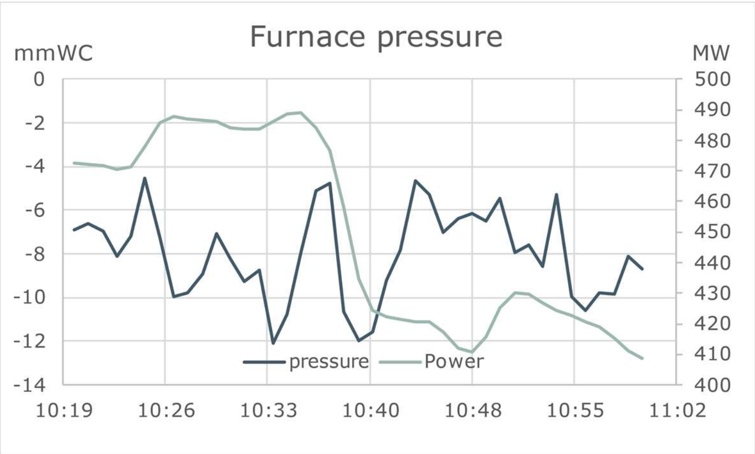


Figure 51. Furnace pressure variation during ramping.

7.2.2.5. Ramp Rate Test – 2nd day of 2nd low load tests

During the second day of testing, the fuel quality was insufficient for conducting the ramp rate test, given the potential risk of tripping. Consequently, a collective decision was reached to perform experiments with the classifier vane settings. Specifically, the angle of the classifier vane was increased to improve pulverized fuel recirculation and fineness:

- Mill C: 4 → 5
- Mill D: 4 → 5
- Mill E: 5.5 → 6.5
- Mill F: 5 → 6

The vanes settings were changed at ca. 13:00 hours, and the flame intensity variation is shown in figure below.

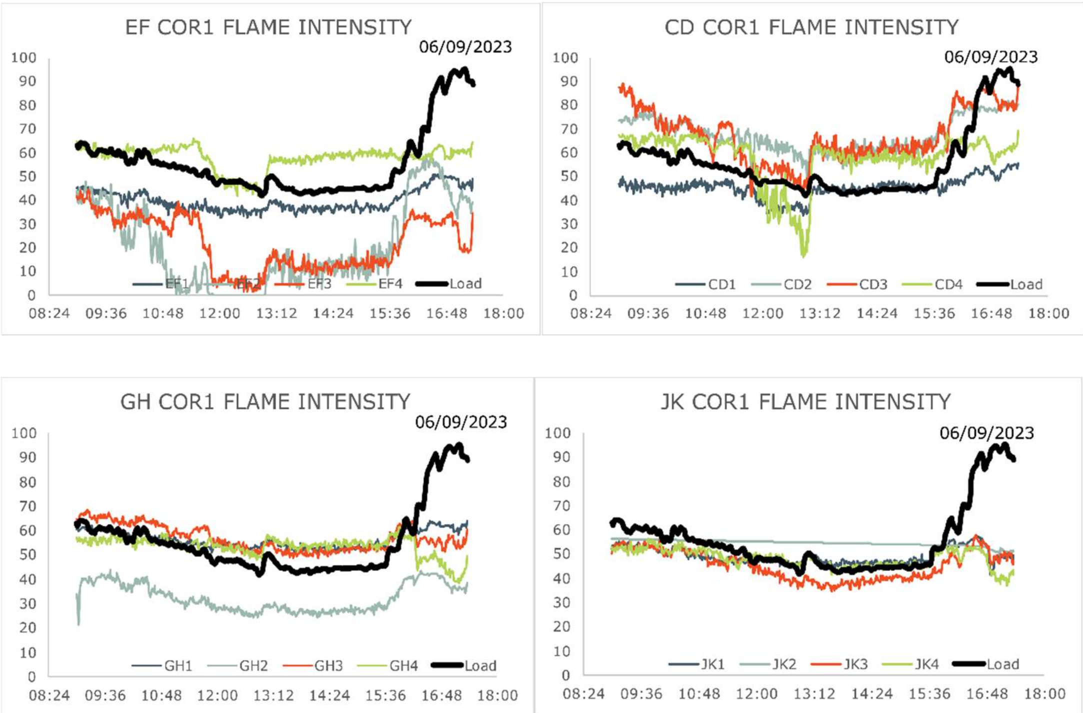


Figure 52. Flame intensity variation 2nd test day.

The most significant impact is observed in mills "CDE." However, this effect remains unnoticeable beyond the last burner row "F."

Another key observation is that the flame intensity increases with the mill load.

Based on the findings, it is highly advisable to undertake more comprehensive planned experiments that involve adjusting various mill and burner parameters. These experiments play a critical role in the optimization of both the mill and combustion processes. They provide valuable insights into how different parameters affect performance and enable the identification of the most efficient operational configurations.

7.2.2.6. *Efficiency*

The EN standard 12952-15 has been used to calculate the boiler's efficiency and/or heat rate by applying its formulas based on the lower heating value. The standard also allows for the calculation of the fuel input, which can then be compared to the measured fuel flow.

Table 7-7. Calculated efficiencies and Heat-rates.

Ramagundam	Unit	28-Feb	05-Sep
EN 12952-15 Fuel efficiency (LHV)	%	91,1	93,0
- Converted to GHV	%	85,6	86,7
Water steam heat (Q_N)	MW	502,8	499,4
Gross Unit Heatrate (LHV)	kcal/kWh	2383	2310
Gross Unit Heatrate (HHV)	kcal/kWh	2514	2466
Gross Unit efficiency (LHV)	%	36,1%	37,2%
Gross Unit efficiency (HHV)	%	34,2%	34,9%
Turbine Heatrate	kcal/kWh	2172	2148
Fired fuel (LHV)	MW	551,8	537,0
Fired fuel mass flow (calculated)	t/h	124,2	138,1
Measured fuel mass flow	t/h	129,3	166,4
Fuel mass flow difference	t/h (%)	5,1 (4,1%)	28,3 (20,5%)

The difference between measured and calculated fuel flow is within an acceptable range for the 1st but not for the 2nd test, where the difference is as high as 20%, it raises concerns that warrant further examination and explanation.

One potential explanation for the significant deviation observed during the second test could be an inaccurate coal quality analysis. It is possible that the actual coal samples contained more moisture than initially reported, leading to a higher calculated fuel consumption and contributing to the observed discrepancies.

The Heat and Mass Balance Diagram (

Figure 53), derived from the measurements and Thermoflex ®, reveals several noteworthy observations:

- The moisture content in the turbine exhaust is relatively low, measuring between 2.6% and 3.2%. This indicates a favorable condition with a high reheat temperature, which effectively mitigates erosion and wear problems in the turbine's final stage.
  According to the original heat and mass balance calculations by BHEL, the moisture content at a load of 250 MW can be estimated at approximately 4.8%, and at full load (500 MW), it reaches around 8.6%.
  This situation presents an opportunity to consider reducing the O2 set point, which would lead to a decrease in the reheat (RH) temperature while ensuring the turbine's operational reliability.

- The condenser is performing well, as evidenced by an acceptable TTD (Terminal Temperature Difference) of 2.7K, in both tests, and a strong correlation between pressure and temperature measurements. This indicates that there is relatively low air entrainment in the condenser. The existing air entrainment is efficiently managed by the vacuum pumps, ensuring the proper functioning of the condenser and maintaining the desired operational conditions.

- The cooling water flow measurement does not match the calculated value. There appears to be a discrepancy between the actual flow rate and the expected flow rate based on the calculations. This inconsistency requires further investigation to identify the root cause and address any potential issues with the measurement or the cooling water system.

- The cold re-heater (RH) temperature measurements exhibit variations, ranging from 315 to 341°C. These variations indicate that the RH temperature measurements is not stable and is subject to changes within this temperature range. Identifying the reasons behind these variations and ensuring a trustworthy RH temperature measurement that remains within a controlled and desired range is important for the proper operation of the system. Further analysis and adjustments may be required to maintain a more consistent and stable RH temperature.

The heat and mass balance model has primarily been developed to enable the estimation of the moisture level in the turbine exhaust, as this critical information is only accessible through calculation based on measured pressure and the calculated enthalpy

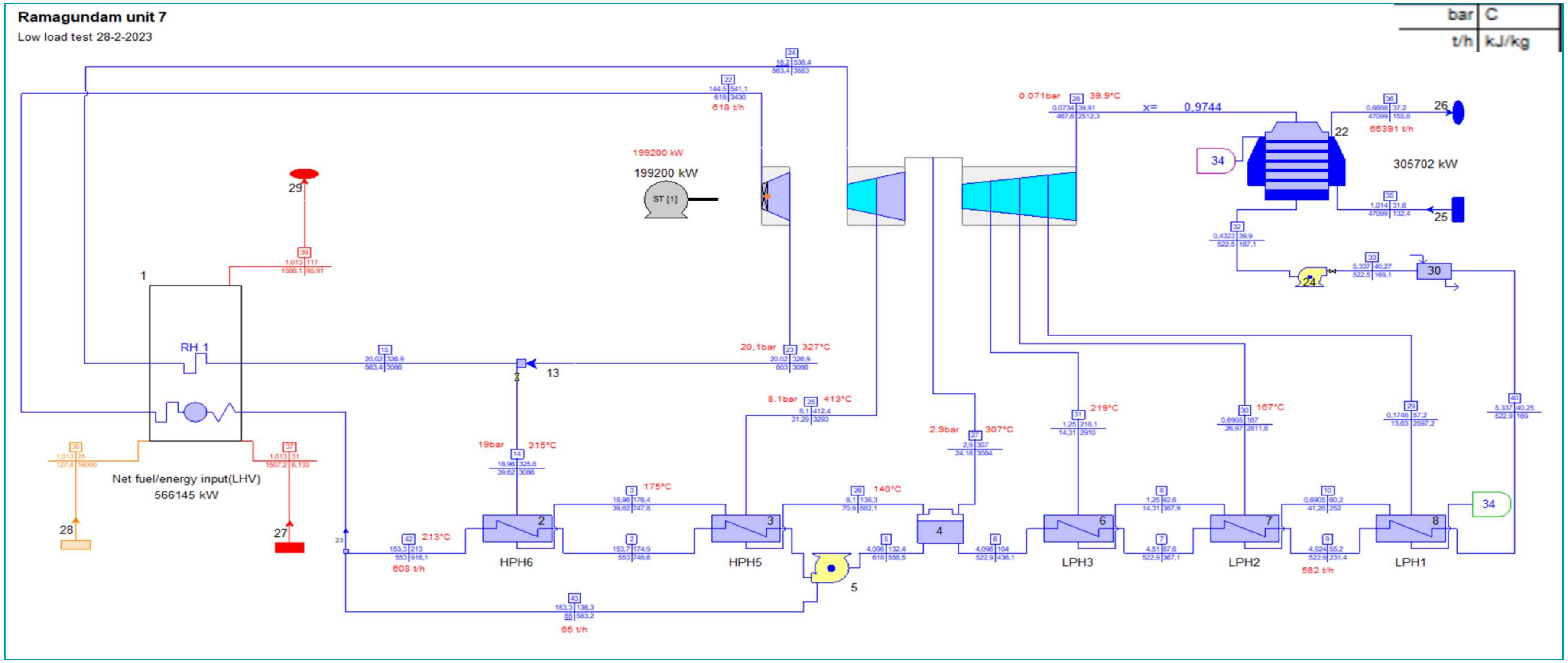


Figure 53. HMB diagram for low load 28/2-2023.

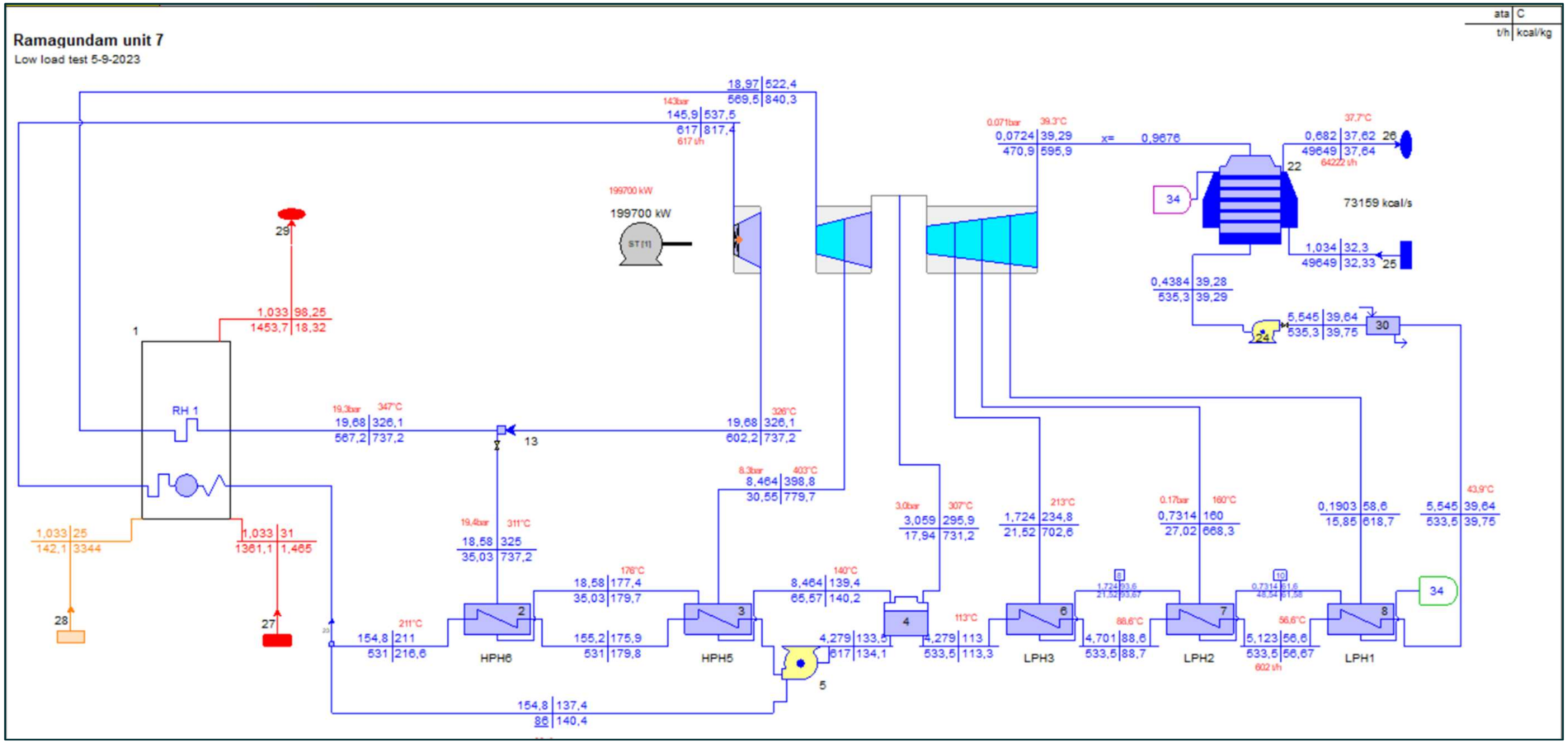


Figure 54. HMB diagram for low load 5/9-2023.

7.2.2.7. Controls

During low loads and ramping tests, the unit was predominantly operated in manual control mode. Although this was necessary for testing purposes, it is highly recommended to optimize the controls to enable unit load control through few set point in the unit control system.

The following outlines several significant characteristics of unit control systems utilized in Danish power plants:

- Load Demand Signal: The Unit Master Controller, employs a load demand signal that is split into separate signals for boiler load demand and turbine load demand. This division considers the maximum dynamic changes that the boiler and turbine can handle. Jump and gradient limiters are adjusted to the individual dynamics of each component. The Unit Master Controller is used to ensure that the boiler and turbine is always in balance, and will ensure that the boiler and the turbine, will only create a change that is within the limits of each other. Also, the Unit Master Controller will ensure that any process limiting factors are utilized in calculating the required set-point. An example could be limiting factors of Mill in operation, feed water pumps, combustion fans, to high condensate pressure etc.

- Feed Forward Control: The unit load demand signal serves as a feed forward signal, guiding and controlling the primary controllers responsible for fuel, feed water, combustion air, steam temperature and turbine operations. The set-point signals are changed gradually to achieve smoother load changes and reduces the need for the slower dynamic feedback controllers to undergo extensive load ramps.

- Damping Effect: The use of feed forward control derived from the unit load demand signal has a strong damping effect on oscillations between the primary controllers. By directly guiding the controllers to the required output, disturbances caused by load changes are minimized. This is especially important in maintaining the proper balance between fuel combustion air and feed water during load variations.

- It is important to note that the unit master controller is not a controller. It is working as a manager or conductor, by directing the main components by their ability to perform, according to the required demand and the actual operational ability at a given the load. It does so by always calculating the required set-points and use feed forward signals for the underlying dynamic feedback controllers.

- Unit Master Control: The unit master control is compound function used to calculate the desired set-points depending on the different load requirements, for the underlying feedback controllers. It also generates pressure set points based on inputs such as electrical load set points, gradients, and potentially district heating set points. It does receive feedback during operation, which is used to calculate the required feed forward signals.

- Gradient Limitation: The Unit Master Control incorporates gradient limitation mechanisms to ensure smooth load transitions. These mechanisms, such as set point controllers (SPC), receive gradient up and gradient down inputs. Operators can adjust the desired gradient, but it may be limited by stress calculators associated with the boiler and turbine. These stress calculators monitor and prevent excessive differential temperatures in the thick metal components, which can lead to thermal stress and premature component degradation.

The primary objective of unit control is to ensure the coordinated operation of the two main components within the system, namely the boiler and the turbine, in order to meet the required load of electricity and heat without causing any component to overload. The Unit Master Controller can be considered as a superior load control mechanism that orchestrates the actions of the boiler and turbine to work in tandem towards a shared objective. The unit control system must simultaneously regulate two key outputs: the net electrical production of the system and the steam flow production from the boiler. By controlling these variables, the unit control system maintains stability and optimal performance throughout the power generation process.

The tasks of the unit master controller are illustrated in the following figure:

It is basically composed of a calculated feed forward signal, and a dynamic PID correction controller which uses either the boiler pressure or boiler load (flow) as a correction. The dynamic turbine correction controller is using either the pressure or Power output from the turbine to correct the feed forward signals.

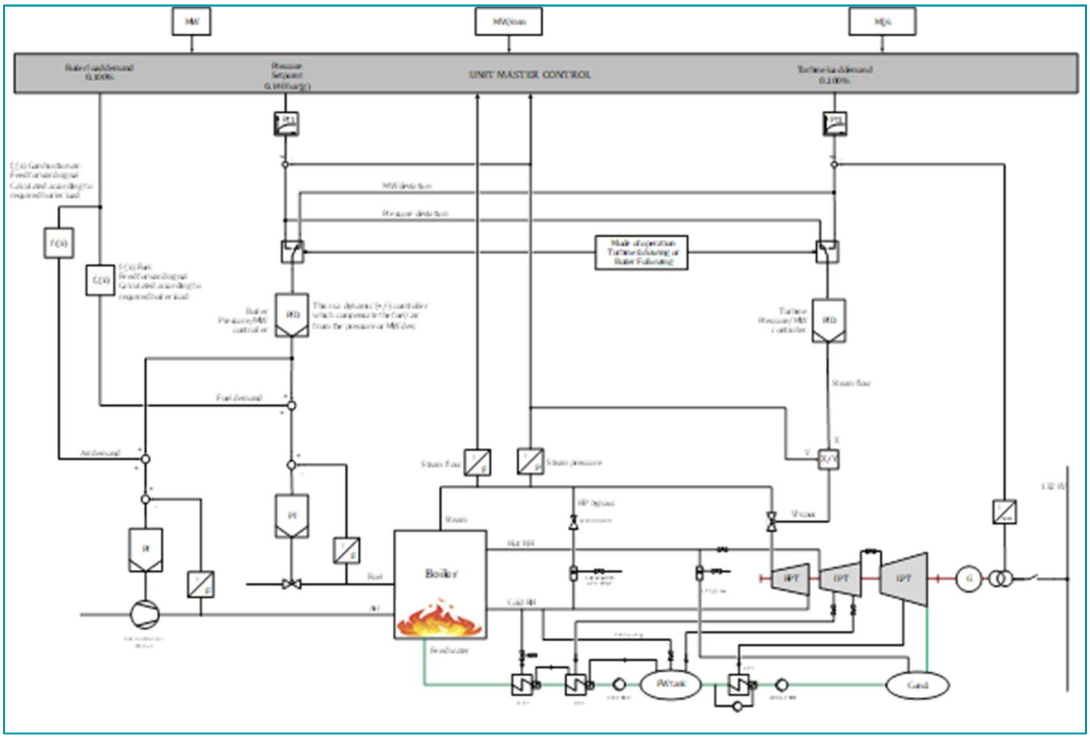


Figure 55. Unit master control design.

The Unit Master Control plays a crucial role in rapidly reducing the overall plant load to a safe level if any primary aggregates fail. This prevents tripping of the entire block. Load limiting intervention mechanisms reduce the unit load demand signal with a predetermined gradient. Additional measures, such as switching the turbine to pressure control and the fuel control to manual operation and stopping the load change until a stable process is achieved, may be employed to stabilize the situation, avoid system disruptions, and protect the equipment from overload.

The Unit Master Controller used in Danish power plants prioritize efficient load management, smooth transitions, and protection of critical components through a combination of feed forward signals, gradient limitation, and load limiting interventions.

The unit load demand signal is divided into a boiler load demand signal and a turbine load demand signal, considering the maximum dynamic changes that the boiler and turbine can achieve at any given load. This division is accomplished through set-point controllers and gradient limiters that are adjusted to accommodate the unique characteristics of each component.

The purpose of the unit load demand signal is to generate feed forward signals that control and guide the primary controllers responsible for fuel, combustion air, feed-water, air, and turbine operations. This approach is particularly important during requirements for fast load changes, as it allows the slower feedback controllers to avoid large load ramps.

By using feed forward signals derived from the unit load demand signal, the primary controllers effectively dampen any oscillations that may occur between them. The feed forward signals provide direct instructions on how to adjust, preventing strong disturbances caused by load changes. For example, maintaining the appropriate balance between fuel and feed water during a load change would be challenging without the use of feed forward signals.

It is important to note that the unit master controller is not a controller. It is working as a manager or conductor, by directing the main components by their ability to perform, according to the required demand and the actual operational ability at a given the load. It does so by always calculating the required set-points and use feed forward signals for the underlying dynamic feedback controllers.

Additionally, the unit master control is responsible for establishing pressure set points. It receives input in the form of set points for electrical load, corresponding gradient, and possibly a set point for district heating.

- Load Control: Unit control is responsible for managing the load demand placed on the drum boiler. The control system adjusts the fuel input and combustion rate to match the required load, ensuring that the boiler generates the necessary amount of steam to meet the electrical demand.

- Steam Pressure Control: The control system adjusts the fuel and air supply to maintain the desired steam pressure.

- Water Level Control: The unit control system monitors the water level and regulates the feed-water flow to maintain a stable level.

- Combustion Control: It monitors parameters such as fuel flow, air supply, and excess oxygen levels to maintain efficient and stable combustion.

- Safety Monitoring: Unit control includes comprehensive safety monitoring. The control system continuously monitors critical parameters, such as steam pressure, water level, and flame stability, to ensure safe operation. It can trigger alarms, shutdowns, or corrective actions in case of any abnormal conditions or potential hazards.

Overall, the main characteristic of unit control for a drum boiler is to control the steam pressure, control load demand, maintain water level, optimize combustion conditions, ensure safety, and optimize efficiency. These characteristics ensure smooth, reliable, and efficient operation of the drum boiler within a thermal power plant.

Ramping control

To ensure a smooth transition, the block net load should change in accordance with specified gradients. This smooth transition is achieved using a set point slider (SWF) block, which receives inputs for both a gradient up and a gradient down.

Typically, the operator has the ability to adjust the desired gradient, such as 5 MW/minute, that the block should follow. However, the gradient may be restricted by stress calculators associated with the boiler and turbine.

The role of the stress calculators is to monitor the differential temperatures in the thick metal components, preventing them from reaching excessively high levels. High temperatures create thermal stress, which accelerates the degradation of these components, reducing their remaining lifetime.

If the differential temperatures exceed the acceptable threshold, the gradients will be reduced, potentially even down to zero, causing the block to slow down its rate of load change.

The challenge lies in accurately predicting when these issues may arise in the future. Actual measurements of thermal tensions always lag behind real-world developments, as these tensions take some time to develop.

Hence, there is a risk of surpassing the maximum limits and depleting the lifetime of components too quickly if a model-based stress calculator that can forecast future conditions is not employed.

Load limiting interventions

One crucial responsibility of the unit master control is to rapidly reduce the overall plant load to the maximum achievable level in the event of a primary aggregate failure. For instance, if a plant has two 60% feed water pumps and one of them fails while operating at full load, the load of the entire plant must be swiftly reduced to 60% to prevent a trip caused by high steam temperatures.

This reduction is achieved through the load limiting intervention mechanism, which rapidly decreases the unit load demand signal to 60% using a predetermined gradient. The primary purpose of this mechanism is to prevent a complete shutdown of the entire block due to the failure of a single main aggregate.

In addition to reducing the unit load demand signal, the turbine is often switched to pre-pressure control to maintain stable boiler pressure through fast turbine valve adjustments. This helps prevent undesirable boiling in the economizer. Furthermore, switching the fuel control to manual operation avoids unnecessary disruptions in the fuel supply.

When the turbine is switched to pre-pressure control and the fuel control is set to manual, the coordinated operation between the turbine and the boiler is temporarily suspended. Essentially, they are no longer operating in sync with the unit load demand signal to achieve a common objective.

Once the situation has been stabilized and brought back under control, the turbine and the boiler can be switched back to automatic mode, and coordinated operation is resumed.

Implementation

Thorough testing is crucial for any new control loops before they are implemented online. Additionally, it is essential for the control room personnel to be educated in the control philosophy and understand how to effectively utilize these new controls. Building confidence among control room personnel in the use of new controls is imperative to ensure the plant can be operated with a sense of assurance and proficiency.

We propose considering the implementation of the following control measures:

- Master unit control – fuel/load coordination.
- SH and RH spray and burner tilt temperature control.
- Boiler drum level control.
- Condensate flow control.
- Oxygen control and fuel/air coordination.
- PA flow and temperature control
- Flue gas temperature control using SCAPH.

- Furnace pressure control.
- Ramping control.
- Automated start-up and shut-down of mills.

These controls, when properly implemented, will contribute to the efficient and optimized operation of the system.

7.2.2.8. Lifetime consumption

In power plant's, the term "lifetime consumption" refers to the gradual wearing out of the materials used in the plant due to prolonged exposure to high temperatures and pressure. Over time, the components such as the pipes and headers will experience damage caused by the chemical reactions and physical stresses that occur during operation. This can eventually lead to a decline in the plant's performance and efficiency, and ultimately may require the replacement of certain parts. Therefore, it is important to carefully monitor the lifetime consumption of the plant and perform regular maintenance to ensure that it continues to operate safely and efficiently for its intended lifespan.

While lifetime consumption monitoring can offer valuable insights into the remaining lifetime and stress status of critical components, it is not considered essential nor necessary for implementing flexible operation.

An online lifetime calculator for a power plant uses mathematical models and algorithms to predict the remaining useful life of the boiler components based on various input data. The input data may include information such as the operational parameters of the boiler, the materials used in its construction, and the environmental conditions to which it is exposed.

The calculator uses this input data to estimate the rate of material degradation or wear and tear on the components over time, based on the specific mechanisms of degradation that are known to occur. The calculations may also take into account the effects of temperature, pressure, and other factors on the expected lifespan of the components.

By continually updating the input data and running the calculations, an online lifetime calculator can provide real-time predictions of the remaining useful life of the components, allowing for proactive maintenance and replacement planning. This can help to optimize the performance and efficiency of the plant, while minimizing downtime and costs associated with unexpected component failures.

There are several calculation models that can be applied to estimate the remaining lifetime of power plant boilers. Here are some common examples:

a) Creep-Fatigue Model: This model combines the effects of high-temperature creep and fatigue damage on the boiler components. It takes into account the loading conditions, materials properties, and operating parameters to estimate the remaining life of the boiler.

b) Larson-Miller Parameter Model: This model uses the Larson-Miller parameter to predict the lifetime of materials at high temperatures. The model is based on the assumption that the lifetime of a material is related to the amount of strain it experiences at high temperatures.
c) Coffin-Manson Model: This model is used to estimate the fatigue life of materials subjected to cyclic loading. It relates the number of cycles to failure to the maximum stress range and the material's fatigue properties.
d) Thermal-Mechanical Fatigue Model: This model takes into account the effects of thermal and mechanical loading on the boiler components. It accounts for the temperature gradients and stresses that are generated during startup, shutdown, and load changes.
e) Probabilistic Model: This model uses statistical methods to estimate the probability of failure of the boiler components. It takes into account the variability in materials properties, loading conditions, and operating parameters to calculate the remaining life of the boiler.

The choice of calculation model will depend on the specific application and available data.

Neither the ASME nor EN standards offer guidance on evaluating the remaining lifespan of pressure vessels and power boilers. These standards do not prescribe a particular calculation model for assessing remaining life. Instead, they provide recommendations on the relevant data to be considered and the factors to be evaluated.

Creep and fatigue are two different mechanisms that are taken into account when considering the behavior and failure of materials.

Creep refers to the time-dependent deformation that occurs in a material when it is subjected to a constant load or stress at elevated temperatures. This gradual deformation takes place over an extended period, often resulting in permanent deformation or even rupture of the material. Factors such as temperature, stress level, and material properties influence the occurrence of creep. It is particularly significant in applications where components experience high temperatures for prolonged durations, such as in power plants, boilers, and turbines.

On the other hand, fatigue is a failure process that arises when a material undergoes repeated cyclic loading, typically at lower temperatures. Fatigue failure is characterized by the accumulation and propagation of micro-cracks within the material due to the repetitive stress cycles. Over time, these cracks grow and can ultimately lead to sudden fracture or failure, even at stresses lower than the material's ultimate strength. Fatigue failure is commonly encountered in structures subjected to cyclic loading, including power plant components.

To summarize, creep is a time-dependent deformation mechanism that occurs under constant stress and elevated temperatures, whereas fatigue is a progressive failure caused by cyclic loading at lower temperatures. Although both mechanisms can lead to material failure, they originate from different loading conditions and exhibit distinct characteristics.

Danish legislation by Order no. 1977 states: *Pressure equipment designed with limited lifetime because of fatigue or creep effects shall latest before half used lifetime be evaluated to determine a programme of lifetime assessment.*

Creep

Component in creep range will normally be designed based on 200.000h creep rupture values. This implies that the expected lifespan has been determined based on 200,000 hours or approximately 22.8 years, assuming the applied stress and operating temperature align with the allowable stress and design temperature, respectively.

The real use of lifetime will be evaluated based on the rules in EN 12952-4 Annex A, as described above as Larson-Miller method. Calculated lifetime will significantly decrease by decreasing operation temperature but will also decrease with decreasing stress and verse versa.

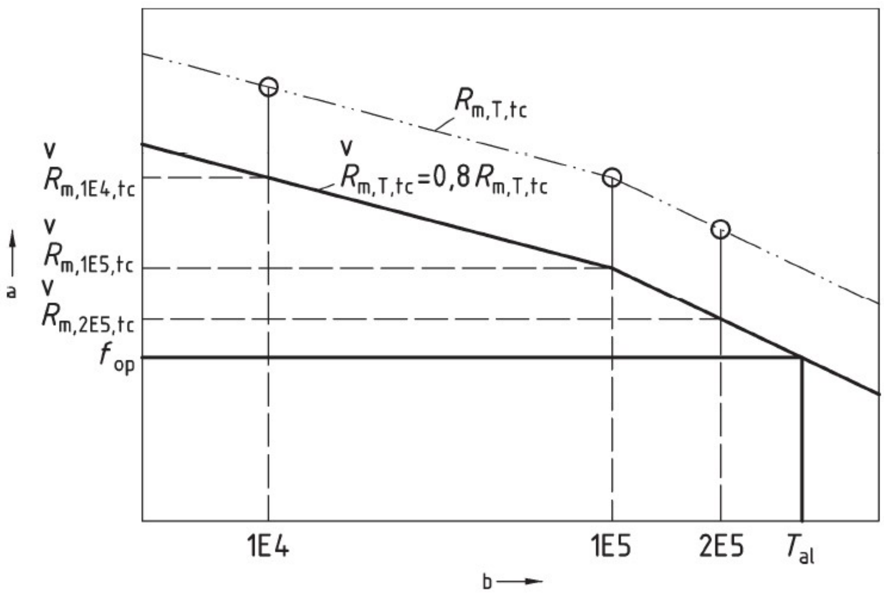


Figure 56. Figure A.1 from EN12952-4, T_{al} is theoretical lifetime.

The following figure is an example from Denmark that demonstrates the calculation of lifetime consumption based on actual operational data.

The KKS-numbers in the table represents:

HAH	Outlet boiler header.
HAJ	Internal boiler connecting piping.
LBA	Live steam piping.
LBB	Hot reheat piping.

The table provided calculates the lifespan of pressure vessels and power boilers based on recorded values of pressure and temperature over a given time period. In this scenario, it is assumed that the stress is solely derived from the internal pressure (known as hoop stress) and will vary directly with changes in pressure. The time period for calculations can range from one month to several years, depending on the availability of data. To obtain more precise results, the time step can be decreased to one minute or five minutes.

It is important to note that if the pressure and temperature values are at their design levels (PS and TS), the calculated lifespan for one hour will be exactly one hour. However, if the pressure and temperature values are lower than the design levels, the lifespan will increase accordingly.

Calculated actual consumed lifetime based on historical data						
Matr.standard:	EN10216-2	Point no:				
Steel no..	1.4922	Steel name:	X20CrMoV11-1			
					X % PS	
Largest stress, σ	Allowable	89,6	N/mm2			
σ ved X % PS					80	
Stress drop at X % PS		80,0	%			
T_{op} =		1,0	timer			
Ao of lows =		803				
No of hours =		803	timer			
Used lifetime in period =		181	timer			
Actual used lifetime in pct. in the period =		**22,6**	%			
Temperature addment =		0,0	°C			
Sum of lifetime / ΔDc			79405,4	9,06E-02		
	Temperature, °C	Temperature, °C	Lifetime	ΔDc	P_{drift} / $P_{bereg.}$	σ
Date Time	**AMV3-LBA10+20-CT002XQ35**	**AMV3-LBA10+20-CP001XQ35**	hours	%	%	%
Design values:	*550*	*274*	1,0	5,00E-04	100,00	100,0
01-02-10 12:54:55	541,7	229,8	3,5	1,41E-04	83,85	83,9
01-02-10 13:54:55	542,4	226,4	3,6	1,39E-04	82,62	82,6
01-02-10 14:54:55	540,9	234,6	3,4	1,46E-04	85,60	85,6
01-02-10 15:54:55	541,7	237,0	3,2	1,58E-04	86,51	86,5
01-02-10 16:54:55	541,8	235,9	3,2	1,57E-04	86,09	86,1
01-02-10 17:54:55	542,1	232,0	3,3	1,50E-04	84,67	84,7
01-02-10 18:54:55	540,8	230,0	3,7	1,35E-04	83,93	83,9
01-02-10 19:54:55	541,5	230,1	3,6	1,41E-04	83,96	84,0
01-02-10 20:54:55	539,7	227,3	4,1	1,22E-04	82,95	82,9
01-02-10 21:54:55	537,8	235,7	4,2	1,20E-04	86,01	86,0
01-02-10 22:54:55	540,5	226,1	4,0	1,25E-04	82,54	82,5

Figure 57. Calculated use and lifetime based on hour values for pressure and temperature.

When considering piping operating in the creep range, it is important to note that the hoop stress may not always be the most critical factor. A flexibility calculation should be conducted to identify significant longitudinal stresses resulting from primary loads such as dead weight and pressure, as well as secondary stresses arising from thermal expansion. In the EN13480-3 standard, these stresses are referred to as S5 stresses. It is crucial to evaluate and address these stresses to ensure the integrity and reliability of the piping system.

In the table below several systems has been calculated both in relation to hoop stress and in relation to longitudinal stresses. Test method for detecting creep damage will be metallographic replication.

	Calculated lifetime				Lifetime assessment
	Design Hoop stress	Stress at operation data			
		Allowable stress	EN13480-3 S5	von Mise	NDT
KKS no.	år	år	år	år	neccessary
HAH81+85	39	48			yes
HAH90BR010	62	36			yes
LBA10BR010	33	67	173	75	yes
LBA10BR601	22	67	89	82	yes
LBA20BR010	33	49	57	38	yes
LBA20BR601	22	49	32	38	yes
LBA30	36	58	81	72	yes
HAJ11+15	78	3262			no
HAJ21+25	78	3262			no
HAJ31+35	251	81			no
HAJ40	265	83			no
LBB10	56	111	634	357	no
LBB20	56	57	304	189	yes
LBB11	27	111	326	275	no
LBB21	27	57	78	130	yes
LBB30	30	78	204	177	no

Figure 58. Calculated lifetime based on operation data for a Danish power plant.

In this particular scenario, the emphasis has been placed on systems where the calculated lifespan is below 80 years, denoted by the red numbers. Through these calculations, critical components have been identified, and a programme has been developed for the assessment of their remaining lifespan. The purpose of this programme is to evaluate the lifetime and condition of these components in order to ensure their continued safe and reliable operation

Fatigue

Use of lifetime in relation to fatigue will be evaluated based on the rules outlined in EN 12952-4 Annex B and EN 12952-3 Annex B and C. Detecting fatigue damage through non-destructive testing (NDT) methods is challenging until a crack actually manifests. The most effective approach is to conduct a fatigue calculation utilizing real-time operational data.

Figure 60 and Figure 60 shows the actual recorded data for the plant and the boiler drum. Figure 59 indicates that the boiler experiences frequent starts and stops on a daily basis, leading to variations in drum pressure and temperature gradients within the boiler drum's wall thickness.

The two temperature gradient measurement points, HAD01CT0001_XJ03 and HAD01CT0002_XJ03, are typically expected to fluctuate around zero. However, there appears to be an offset between the two measurement points, as well as both points showing an offset in relation to zero. This suggests a potential calibration issue that needs to be investigated.

The calculations provided assume that the recorded temperature difference shown in Figure 60 accurately represents the real temperature difference amplitude. Based on this assumption, a lifetime consumption can be calculated.

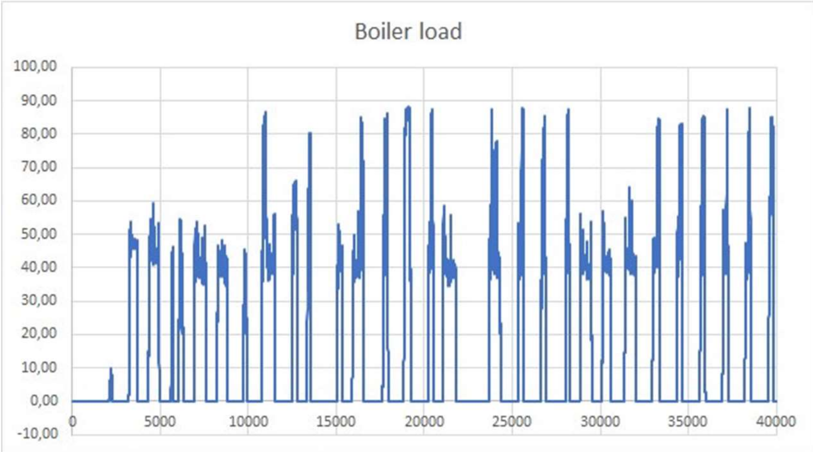


Figure 59. Boiler load one month, 7 min. values.

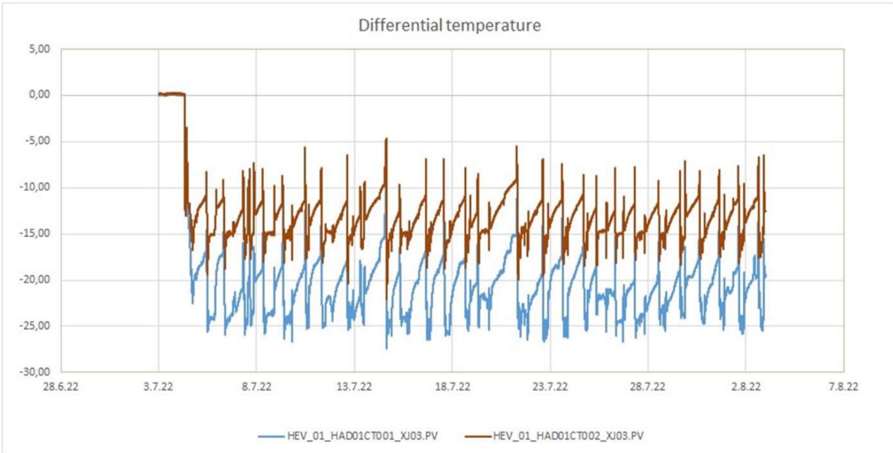


Figure 60. Boiler drum differential temperature in two points, end and middle.

Figure 61 shows a lifetime calculation based on fluctuating temperature gradients in the boiler drum. The operation time period in this case is one month as indicated on Figure 109 and Figure 110. The table calculates the max. allowed temperature difference for each load regime where the considered time interval is assumed to be representative of the entire period.

EN12952-3, Annex C, Tabel C-2, calc. of max allowable temp. gradient							
Example 2 Calculation of the fatigue loading, in accordance with clause 13							Inputfelt
and annex B: Calculation of the admissible temperature gradient							
This calculation shall be carried out for a different number of cycles such that SUM (n/N) < = 1 if the load							
regime is specified. If the load regime is not specified see 13.1.2							
Drawing No.: HEV 57.20.17845/0.100		**HAD01**					
Materialestandard:							EN10028-2
Steelno.							ATM NiMoV
Steelname:							WB314
Material properties from EN 12952-3/EN13480-3 Annex D							
Design levetid	40	years					
Data fra:							
Load regime no:				1	2	3	
cycle type:				4.7.22	2 no's./month	28 no's./month	
Calculation pressure	pc	barg		140			
Calculation temperature	tc	°C		337			
Operating pressure	po	barg		118	118	118	
min. cyclic pressure	pmin	barg		0	18	35	
max. cyclic pressure	pmax	barg		118	118	118	
min. cyclic temperature	tmin	°C		20	200	240	
max. cyclic temperature	tmax.	°C		330	320	320	
water/steam, water=true, steam=false				FALSE	FALSE	FALSE	
Is magnetite created? yes=true, no=false				FALSE	FALSE	FALSE	
Notch factor	C_k			1	1	1	
Numaber of cycles in a month	N_month			1	2	28	
Number of cycles	N			480	960	13440	
Usage	Util			0,4	0,4	0,4	
N / Util	Nas			1200	2400	33600	
Outside diameter of the drum	do	mm		1960	1960	1960	
Mean wall thickness of the drum	ems	mm		80	80	80	
Outside diameter of the branch	dob	mm		168,3	168,3	168,3	
Mean wall thickness of the branch	emb	mm		20	20	20	
Alpha_m	α_m			3,1	3,1	3,1	
R_vt EN12952-3 sec. 5.5 more accurate	vt	°K/min		2,3	2,2	2,2	
R_vt EN12952-3 sec. 5.5 conservative	vt	°K/min		0,0	0,0	0,0	
Factor for partition of the thermal stress range	g_s			0,5	0,5	0,5	
dt1 (begin of start up) = (f1 - Sp,min)/W (13.4-12a)	dt1, start up	°K	1	-42,16	-35,71	-15,14	
dt1' (end of start up) = (f1 - Sp,max)/W (13.4-12b)	dt1', start up	°K	2	-106,27	-89,57	-59,77	
dt2' (end of shut down) = (f2 - Sp,min)/W (13.4-12d)	dt2', shut down	°K	3	106,27	89,57	59,77	
dt2 (begin of shut down) = (f2 - Sp,max)/W (13.4-12c)	dt2, shut down	°K	4	42,16	35,71	15,14	
vt1 (begin of start up) = dt1 × V (13.4-13)	vt1, start up	°K/min	5	10,62	8,72	3,66	
vt1' (end of start up) = dt1' × V (13.4-13)	vt1', start up	°K/min	6	26,77	21,86	14,46	
vt2' (end of shut down) = dt2' × V (13.4-13)	vt2', shut down	°K/min	7	-26,77	-21,86	-14,46	
vt2 (begin of shut down) = dt2 × V (13.4-13)	vt2, shut down	°K/min	8	-10,62	-8,72	-3,66	

Figure 61. Calculated max. allowable temp. gradient for a given load regime in a certain time.

Figure 61 show the calculated lifetime for each load regime when max temperature gradient amplitude is applied.

Drawing No.:	**HEV 57.20.17845/0.100**			Cycles	LoadCycles	Use of
HAD01	Data: HEV_01_HAD01_03-07-2022--03-08-2022_with Tsat.xlsx					Lifetime
					Max	
Δt (dt1)*f(gs)	Load regimes					
°C	4.7.22	2 no's./month	28 no's./month	Σn	N	n/N
-42,16	1			1200	1200	1,00E+00
-35,71		2		2400	2400	1,00E+00
-15,14			28	33600	33600	1,00E+00
Calculated use of lifetime where 1,0 is 100% use of lifetime						**3,00E+00**

Figure 62. 100% use of lifetime for each load regime when max temperature gradient amplitude is applied.

Figure 62 show the calculated lifetime for the boiler drum when recorded temperature amplitudes are applied.

Drawing No.: HEV 57.20.17845/0.100				Cycles	LoadCycles	Use of
HAD01	Data: HEV_01_HAD01_03-07-2022--03-08-2022_with Tsat.xlsx					Lifetime
					Max	
Δt (dt1)*f(gs)	Load regimes					
°C	1200	2400	33600	Σn	N	n/N
9,00	1			1200	28172	4,26E-02
8,00		2		2400	57289	4,19E-02
7,00			28	33600	103705	3,24E-01
Calculated use of lifetime where 1,0 is 100% use of lifetime						**0,41**

Figure 63. Calculated use of lifetime when recorded temperature amplitude is applied.

In practice, more months with recorded operation data is evaluated and based on these an overall lifetime consumption can be predicted for the boiler drum in operation until today.

Monitoring of lifetime consumption:

The increased flexibility of the coal fired power plants has led to increased number of start-ups and load changes, including steeper gradients. Additionally, in the case of once-through boilers (specifically Benson boilers), the transition from Benson mode to circulation mode is critical. As a result, there is a need to monitor the lifetime consumption of critical thick-walled components within the boiler.

The DCS suppliers for the power plants in Denmark offers packages for monitoring and prediction of critical component exhaustion (fatigue) in accordance with the European EN 12952-4 specification and the German TRD 301 and 508 rules. Examples of such packages include ABB Optimax BoilerLife Monitoring and Siemens Leda (**Le**bens**da**uer).

The calculations require preferably three representative measuring points pressure, temperature at the inner surface and middle wall. Alternatively, a pressure and a medium temperature measurement can be used.

The results of the calculations are used for monitoring periods or incidents where the lifetime consumption has been increased. Based on these findings, changes in procedures and/or regulations has been implemented to mitigate excessively lifetime consumption in the future.

Example of extended lifetime consumption

In the Daily Evaluations Report for the Live Main steam pipe LBA12 (Nordjyllandsvaerket unit 3) it was discovered that Y piece LBA12 had an unnormal high Total exhaustion of 0,18 % (21,74%-21,56%) on the 5/1 where there was a turbine trip.

OPTIMAX
BoilerLife Reports

Daily Evaluations Report
Nordjyllandsvaerket Unit 3

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Tag Name (KKS) LBA12
Evaluation from 01/01/2023 00:00:00
to 06/03/2023 00:00:00

Calculation ID	Date/Time of Calculation	Fatigue without Classification	Fatigue with Classification	Creep without Classification	Creep with Classification	Due to Residual Extremes	LCF Due to Ref. Comp.	Creep Due to Ref. Comp.	Total Exhaustion [%]
6038	2023-01-01	2.202494	2.204520	19.272855	19.167200	0.089621	0.000000	0.000000	21.564970
6039	2023-01-02	2.202494	2.204520	19.272958	19.167318	0.089621	0.000000	0.000000	21.565073
6040	2023-01-03	2.202494	2.204520	19.273205	19.167583	0.089621	0.000000	0.000000	21.565320
6041	2023-01-04	2.202494	2.204520	19.273517	19.168060	0.089621	0.000000	0.000000	21.565632
6042	2023-01-05	2.202494	2.204520	19.273755	19.168505	0.089621	0.000000	0.000000	21.565871
6043	2023-01-06	2.227194	2.221999	19.273941	19.168894	0.244435	0.000000	0.000000	21.745571

Figure 64. Daily Evaluations Report, LBA12.

An examination of the incident showed that the trip resulted in big temperature difference between inner wall temperature LBA12CT101 Figure 65 and middle wall temperature LBA12CT102 (blue curve in Figure 65) above from normal 8°C to 100°C in few minutes.

In the following start-up the steam temperature LBA12CT901 (green curve in Figure 65) increased with 3,5 °C/min. which led to big differences in material temperatures up to 50°C.

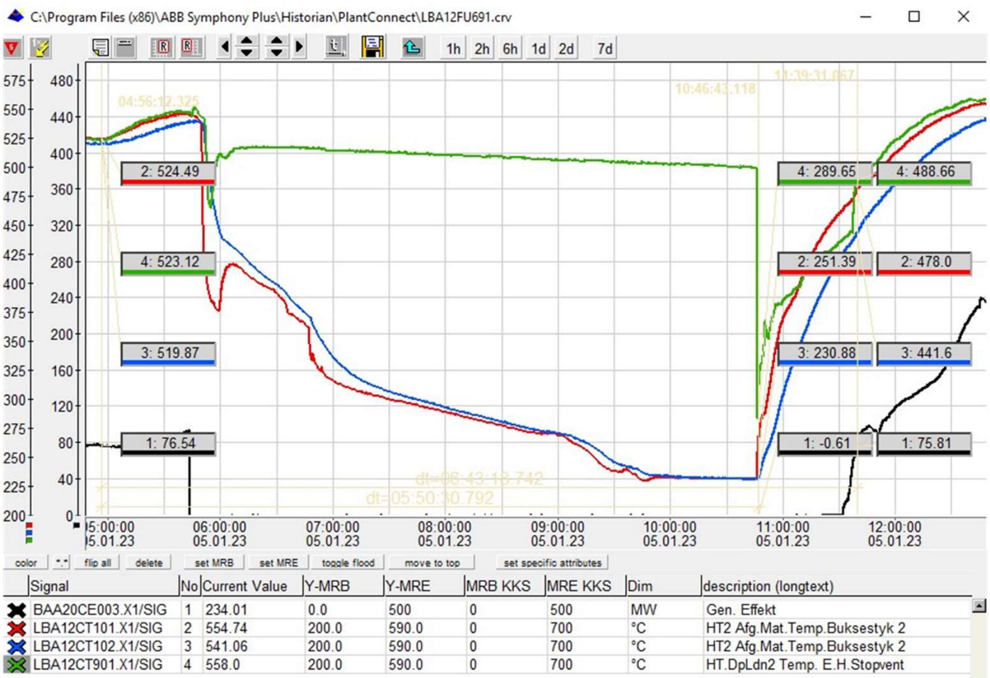

Figure 65. Boiler and turbine trip 5/1, Material- and steam temperatures LBA12.

7.2.2.9. *Summary of findings on the 1st and 2nd low load test at Ramagundam*

Mill load

The operation with two mills at low load is only feasible in very rare cases where high-quality coal is readily available. However, during testing with lower-quality coal while operating on four mills, it was observed that operating with three mills at an average load of 88% was feasible and had the potential to improve flame stability.

- The mill load needs to be as high as possible in order to enhance combustion stability.

Mill in- and outlet Temperatures

The outlet temperatures vary between the mills which implies different conditions within the mills. The different conditions can be:

- Different wear and operating time since last overhaul. Each mill may have undergone maintenance or overhaul at different times, resulting in variations in wear and performance.
- Different inlet PA temperature. This can lead to differences in coal drying and combustion efficiency.
- Different air/coal ratios. Leads to varying residence time and differences in coal drying and combustion efficiency.
- Different classifier wear as recirculation setting. This can lead to variations in pf. size distribution and hence combustion behavior.

On one occasion, in the 2nd test, the outlet temperature for mill "C" reached 90°C which triggered the temperature control to reduce the inlet temperature with a steep downward ramping. An optimized control system can and should prevent such excessive temperature fluctuations.

During the tests, it became evident that in the wet monsoon season, raising both mill inlet and outlet temperatures is necessary for effective drying due to increased moisture in combustion air and coal. However, increasing mill temperature from 90 to 100°C poses fire risks. Consultation with BHEL, the OEM, is advised for safety and guidance.

- The mill outlet temperature shall be as high as possible to increase pf. dry-out.
- The mill temperature control needs to be optimized.

Air Preheaters

To raise the inlet temperatures effectively, it is important that the air preheater cold bypass can be fully closed. During the second test, there were difficulties in achieving this because the dampers were requested to close but were unable to do so due to damper leakages. This issue concerning the damper leakages can hinder the control of inlet temperatures and impact the overall combustion process. It is suggested that this issue is addressed during the normal maintenance outage.

- The PA bypass dampers needs to be maintained.

SCAPHs

The non-operational Steam Air Preheaters (SCAPHs) in the unit pose challenges, especially during expected low loads. If SCAPHs were operational, they could raise flue gas temperatures, preventing corrosion risks, while increasing the PA temperatures and pf. dry-out which is especially important during the monsoon season. Therefore, it is suggested to:

- Maintain the SCAPHs and use them in low loads.

Coal Dust distribution

There is a significant problem with the pf. distribution from the coal mill to the burners, with deviations as high as 45%. The primary implication of this problem is that the intended air/coal ratio is not realized, which, in turn, results in suboptimal combustion, potentially leading to an unstable flame and decreased overall efficiency in the combustion process.

To mitigate this problem it is imperative to balance out the distribution of pf. However, the unit lacks the necessary equipment to perform this operation effectively. Hence, it is proposed to

- Install new adjustable orifices in the coal pipes.

We recommend engaging BHEL (Bharat Heavy Electricals Limited) in this project, as we have confidence in their expertise and knowledge regarding this technology.

Coal Dust Fineness

During the testing, the fineness of the pf. was a slightly below the anticipated level. On the 2nd day of the 2nd test the classifier recirculation settings was increased and as a result the flame intensities were increased. It's important to note that roller pressure is equally significant in the grinding process and requires testing.

Therefore, it is proposed to

- Conducting more extensive tests to determine the optimal classifier setting for recirculation more definitively.
- Conduct extensive testing to determine the optimal roller pressure for attaining better pf. fineness.

Flame Signals

During both tests, notable variations in flame intensity levels were evident, accompanied by intermittent flickering. These observations can likely be attributed to the previously mentioned issues, including problems with pulverized fuel (PF) distribution, insufficient fineness, the absence of pf. dry-out, and potential roping. However, it's important to consider that the problem may also be associated with the flame scanner equipment. Hence:

- Verify flame scanner signals.

The verification process should start with visual inspections and then advance to equipment maintenance and calibration. Ultimately, it may be necessary to consider replacing the current scanners with more advanced and modern versions.

Controls

Controllability is of utmost importance in a coal-fired thermal power plant, especially during low load operation and during load ramping.

The challenges with controllability can be traced back to two distinct underlying factors:

1. Inadequate control-loop designs
2. The deterioration of equipment due to wear and tear.

For the controls to function effectively, it is imperative that the equipment operates in accordance with its intended design.

During both tests it has been observed that the following controls needs to be modified and optimized in order to function effectively during low loads and ramping:

- Drum level control.
- SH, RH temperature control.
- Combustion air and fuel coordination control.
- Mill ramping control.
- Mill temperature control.

It is highly recommended to optimize the controls to enable unit load control through few set points in the unit control system. These controls, when properly implemented, will contribute to the efficient and optimized operation of the system.

8. Pilot project in Raichur

The development of the pilot follows the roadmap for success, previously presented (See Figure 21).

8.1. Document the current low load

The paragraphs documents the achievable low load condition for Raichur unit 3, before any corrective measures are implemented. The test was performed exclusively by the staff at Raichur, without participation of the Danish project group from DEA and COWI. The test conditions and setup were not discussed and reviewed beforehand by DEA/COWI.

The date for the test was June 24th, 2022. Test data for three hours between 15:00 and 18:00 has been submitted for analysis by COWI. The purpose of this test and report is to document the current low-load, and it will serve as a reference for upcoming tests at lower loads.

Summary

This low-load measurement shows a higher low-load of approx. 67% compared to the anticipated 60%. From the data received, it was not entirely clear about which were the limiting factor(s). It would be beneficial if the test responsible can explain this at a later stage, as it is not evident from the measurements alone.

The test was performed with different settings than recommended, primarily low burner setting with 4 instead of 3 operating mills. Several key measurements and analysis, which are essential for the well-functioning of the pilot, were not available in the data set shared, especially coal and PF analyses.

The measurements indicates few challenges, which should be addressed by the test responsible:

- The O_2% is very high, approx. 3%-point higher than anticipated.
- 4 coal mills are in operation, one more than anticipated.
- The burner setting is “mid firing”, while “high firing” is anticipated.
- Many measurements were missing in the data for performing a proper analysis (compared to the list previously shared).
- The load stability was too unstable. During one hour between 4 and 5, the power output varied between 145 and 137 MW:

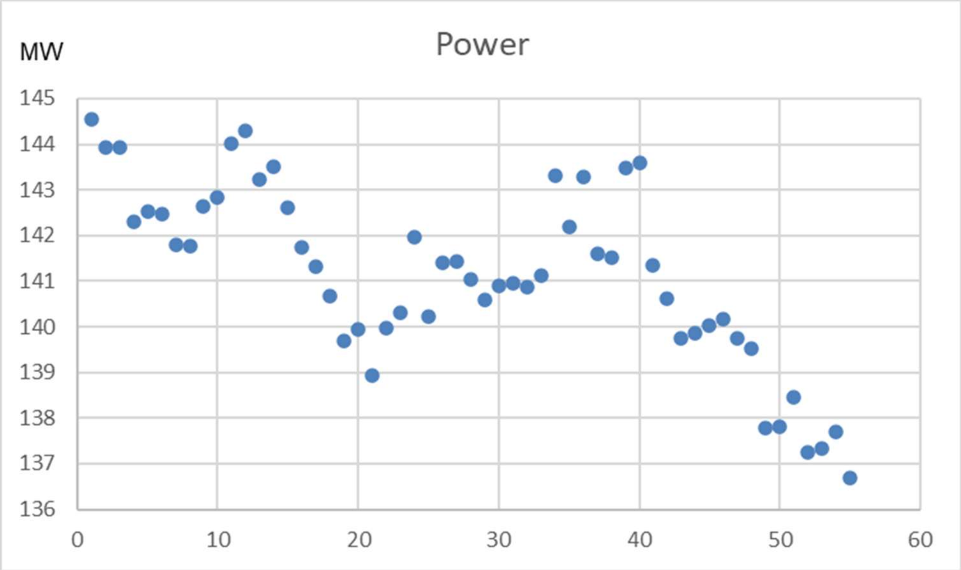

Figure 66 Gross power output during 4:00 and 5:00

Main performance data (averaged)

The main test data is show in below table. For convenience "Unit 3 Data Sheet Design" (predicted performance) is also shown. The measurements are averaged between 4:25 and 4:35, in the most stable timeslot available.

Table 8-1 Averaged measurements

Load	%	60	67,3
Gross power	MW	126	141,3
Steam / Water:			
Superheater out	t/h	376	443,9
Reheater out	t/h	344	x
Feedwater	t/h	342	476,3
SH spray	t/h	34	9,3
RH spray	t/h	0	0,0
Air:			
AH outlet (PA)	t/h	117	x
AH outlet (SA)	t/h	341	x
Total Combustion Air	t/h	549	619,5
Fuel:			
Coal	t/h	84	102,1
Steam / Water temperatures:			
Sat. Drum	°C	344	382,6
HT before spray	°C	408	x
HT after spray	°C	368	x
HT outlet	°C	540	540,0
RH inlet	°C	325	345,3
RH outlet	°C	540	540,0
Eco inlet	°C	218	223,6

Eco outlet	°C	289	x
Steam / Water pressures:			
HT outlet	kg/cm^2 (g)	150,8	141,7
Drum	kg/cm^2 (g)	154,3	146,8
ECO inlet	kg/cm^2 (g)	156,8	x
RH inlet	kg/cm^2 (g)	21,2	x
RH outlet	kg/cm^2 (g)	22,1	x
Air:			
Ambient	°C	35	x
AH outlet (PA)	°C	296	x
AH outlet (SA)	°C	292	278,8
Gas:			
AH inlet	°C	313	x
AH outlet	°C	118	x
O_2	%	4,99	6,8
CO_2	%	14,25	x
NOx		x	x
Mills:			
No in operation		4	4
Mill load (avg)		81	74,4
C	%	81	74,4
D	%	81	70,5
E	%	81	78,2
Air flow per mill		55	61,3
C	t/h	55	60,0
D	t/h	55	62,1
E	t/h	55	61,8
PA ratio	-	1,96	2,4
C	t/h	1,96	2,3
D	t/h	1,96	2,5
E	t/h	1,96	2,3
PA temperature inlet	°C	222	x
Mill outlet temp	°C		80,4
C	°C		80,2
D	°C		80,9
E	°C		80,0
Burners:			
Avg. Tilt		25	80,0
Fineness (200)	%	70	x
Coal:			x
Carbon	%	x	x
Hydrogen	%	x	x
Sulphur	%	x	x
Nitrogen	%	x	x
Oxygen	%	x	x
Moisture	%	x	x
Ash	%	x	x
Higher Heating Value	kcal/kg	3650	x
Fixed Carbon	%	29,4	x

Volatile matter	%	21,7	x
Moisture	%	8	x
Ash	%	40,9	x

The flame intensities are measured between each burner level in each corner.

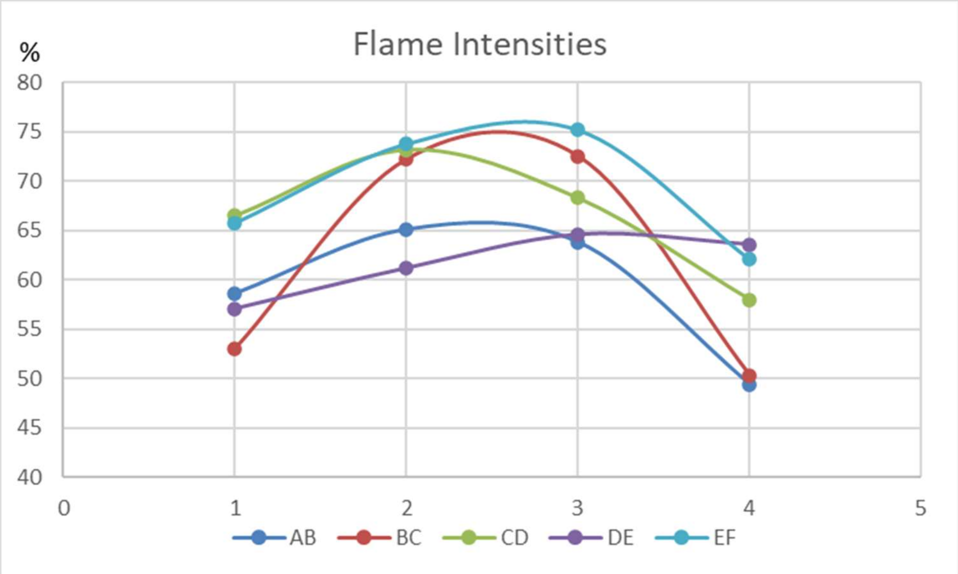

Figure 67 Flame Intensity

The following turbine and pre-heater measurements were recorded:

Table 8-2 Turbine and preheater measurements

Load	%	60	67,3
Condenser pressure	kg/cm^2	0,0812	0,1932
Condenser temperature	°C	41,4	53,7
Cooling water temperature inlet	°C	33	28,7
Cooling water temperature outlet	°C	x	36,1
Cooling water flow	m3/h	x	x
Condensate temperature LPH1	°C	49,4	54,5
Condensate temperature LPH2	°C	79,8	56,9
Condensate temperature LPH3	°C	107,8	106,9
Deaerator temperature	°C	143,2	152,5
Feedwater temperature HPH1	°C	179,7	185,6
Feedwater temperature HPH2	°C	218,4	221,4
Bleed 1 pressure	kg/cm^2	0,1364	x
Bleed 2 pressure	kg/cm^2	0,5254	x
Bleed 3 pressure	kg/cm^2	1,479	x
Bleed 4 pressure (DEA)	kg/cm^2	4,246	4,6
Bleed 5 pressure	kg/cm^2	10,37	x
Bleed 6 pressure	kg/cm^2	22,64	x

More data, than reproduced in above table, were submitted, but chosen not to be shown here. Although no turbine vibrations were measured, the experts encourage to record them, as they will be useful parameters to be benchmarked for future reference.

Observations

- A large part of the measurements were not available in the dataset provided, to make a proper evaluation of the obtained low load, compared to the list previously shared. This could impact the good performance of the upcoming pilot project. The experts warmly suggest to record such data.
- From the measurements provided, it results that the load was very unstable. As a result, the measurements are not entirely reproductive because of large instability in the system. The boiler combustion control loops are expected to pose potential for optimizations.
- The re-heater temperature is 540 °C (SP), while the RH spray is zero; this represents a challenge that should be discussed between the team and the experts. If the RH spray is, as expected, zero, then the RH temperature will fall below the SP. The RH temperature must be serviced and recalibrated, and an update of the RH temperature control concept may be necessary.
- The deviation between HP and feed-water flow is too high and not acceptable, according to technical standards. As part of the data shared, no information regarding blowdown or draining is available. During a test blowdown and all boiler drains must be closed. This deviation should be discussed between the team and the experts.
- Drum level is fluctuating, more than 30% as compared to fluctuation in steam-flow of 2%. Change of drum level control concept is suggested.
- The HP steam pressure is 9 kg/cm2 below the anticipated pressure. This should be discussed between the team and the experts.
- The O_2% is very high, approx. 3%-point higher than anticipated. High O_2% results in increased fan power consumptions, and higher AH outlet temperatures. Hence lower efficiency. This should be discussed between the team and the experts.
- 4 coal mills are in operation, one more than anticipated, resulting in low mill loads. This should be discussed between the team and the experts.
- The mill outlet temperature is too low. This is not unusual as the flue-gas temperature before the AH drops in lower loads drawing the PA temperature down. Too low mill temperature will worsen the combustion stability and increase the risk of tripping. The steam AH could and should have been put into operation to mitigate this.
- The burner setting is not ideal by BCDE, not using F. The burner setting is “mid firing”. The burners in the lower part of the furnace are in operation. By setting a higher firing the RH temperature will increase. This should be discussed between the team and the experts.
- Flame intensities are not ideal as the variation is too high. By adjusting and optimizing the PF and PA distribution a much better and uniform intensity variation can be expected.

Suggestions for next tests

Based on the current measurement, the following operational settings are suggested to improve the combustion stability:

- Increase mill outlet temperature to 90°C
- Use top mill/burner settings T4(C-F) / T3(D-F)
- Increase mill load by reducing number of running mills
- Operate mills at same loads
- Reduce RH water injection, by optimizing the RH water injection control
- Reduce O
- Optimize PF distribution in coal pipes
- Optimize PA distribution

For best possible documentations of the test, it is essential to take coal samples of the fired coals and have an ultimate analysis made.

The following extra data are required to document the next tests, so to have proper base of comparison among the tests performed:

- Coal analysis
- PF fineness
- PF flow measurements (coal pipe distribution)
- UBC
- DP coal mill
- Coal mill motor power
- PA temperatures after AH
- PA temperatures before mills
- ECO outlet temperature
- AH outlet temperatures (air and flue-gas)
- H2O content in flue-gas
- RH pressures
- RH temperatures before and after water injections
- Drain temperatures after each pre-heater
- Turbine bleed temperatures and pressures for each bleed
- Cooling water outlet temperature
- Cooling water flow
- Turbine vibrations

Data shared in an Excel file format should clearly show measurement id-numbers and measurement units.

8.2. Perform, evaluate and document the 1st and 2nd low load tests

8.2.1. Protocol and plan for flexible operation

The protocol and pilot is intended to detail the plan for the first low load test at Raichur unit 3. This should take place after the “current low load” (see Chapter 8.1) has been performed and documented in the document. The following two steps are: 1) to prepare the unit by performing necessary optimizations and 2) propose a plan for conducting the test at the plant, in preparation for the first low load test.

Protocol for Preparations

The following protocol refers to the preparations suggested to be addressed at the plant by the plant personnel. The plan is twofold, firstly some preparations at the plant is advisable, and secondly a plan for conducting the test at the plant is presented.

- **Measurements**

Based on the learnings from the “*Current Low Load Test*” (Chapter 8.1) the following measurements are suggested to be addressed:

- AH PA flow
- AH SA flow
- AH fluegas outlet temperature
- AH PA outlet temperature
- ECO fluegas temperature
- Feed water flow
- HP steam flow
- NO_X
- CO_2
- Coal flow to mill B
- PA temperature mill inlet – after mix

The measurements previously shared are suspected to be erroneous and should be serviced and recalibrated.

- **Missing measurements**

Several necessary measurements were not available for the *“Current Low Load Test”*, especially the following measurements were missing and should be made available:

- Coal mills:

- Power consumption
- Differential air pressure
- Grinding pressure
- Classifier settings

- Burners
    - Tilt
    - SA/TA damper settings
- Turbine
    - All bleed temperatures (some were missing)
    - All bleed pressures (some were missing)
- Condensate / feed-water
    - All temperature before and after preheaters (some were missing)
    - All drain temperatures (some were missing)
- Turbine vibrations

The reader can refer to Chapter 6.3, for a full list of required measurements. -The transfer of measurements to Excel should be automatized when possible.

- **Mills**

The boiler should be prepared for operating with "high-firing" by using mills C-F

- **Steam Air Preheater**

The SAP should be able to operate and secure the mill outlet temperatures.

- **Coal sampling**

Preparations necessary for taking coal samples during the test. Optimally one sample per hour for getting an overview of the LHV/HHV variations.

- **P.F. sampling**

Taking pf. samples from the coal pipes are necessary for analyzing the fineness by sieve tests.

- **Controls**

One take-away from the *"Current Low Load Test"* was that the boiler drum level control as well as the RH super-heater water injection control needs to be optimized.

- **Optimization**

The pf. distribution from each mill (C-F) shall, if possible, be adjusted.

- **Maintenance**

The mill and burner internals shall be inspected and if necessary, worn-out equipment replaced.

- **Before commencing the test.**

The following preparation should be done at the unit and plant selected, prior to the test.

- Soot blowing
- Ashing (emptying of ash hoppers)
- Coal mill reject box shall be emptied
- Furnace water seal verified
- The unit must be isolated both electrical and, on the water/steam side
- No known equipment problems

Test plan

A total of three days should be allocated for the pilot test: 1 day for preparation and 2 days for the testing.

On the day before the test, it is suggested to meet all plant personnel that will be present during the two test days. The agenda will be discussion on the test plan and to perform a risk evaluation.

Two days are envisaged for performing the tests. The first day is expected to be used for experimenting with the boiler load and settings to find the best and most stable low load. On the second day the unit shall then operate at this load in at least 8 continuous hours.

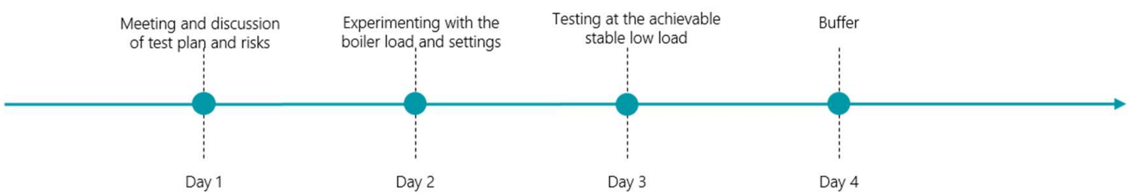

Figure 68 Draft plan for pilot in Raichur

- **Reducing load**

Oil support is required for stabilizing when reducing the load beyond the known *"current low load"* and taking mills out. All operations must be done by the control room personnel and supervised by plant engineers. COWI/DEA's role is to support, observe and assist.

- **Suggested plan for 1st day tests**

The following plan is only a suggestion and should be used as an input for a common final plan.

1. Bring the unit down to “current low load”, 141 MW
2. Change mill setting to high firing
3. Reduce to 3 operating mills D-F
4. Reduce load to 126 MW – 60% (mill load 81%)
5. Reduce to 105 MW – 50% (mill load 69%)
6. Reduce number of mills to 2 (E-F) with oil support (mill load 90%)
7. 90 MW without oil support – 43% (mill load 90%)
8. Reduce load gradually.
9. The goal is 84 MW (mill load 83%)

This roadmap is probably time consuming, and the number of steps could be reduced.

During the test day both coal- and pf. samples shall be collected. If possible, the sieve analysis shall be conducted, and the data is available prior to 2nd test day.

8.2.2. The Pilot

The initial test occurred on Marts 5th and 6th, 2023, while the follow-up test took place on August 30th and 31st, 2023.

The Danish team, consisting of representatives from the Danish Energy Agency (DEA) and their consultant, COWI, supervised the planning and execution of the test. The operational responsibilities of the unit were managed by the plant staff, with oversight from officials of KPCL (Karnataka Power Corporation Ltd). Additionally, during the first test, a representative from BHEL (Bharat Heavy Electricals Limited), the primary OEM, was attending along with representatives from CEA. During the second test, a representative from Grid India attended. The testing was split in 4 days, and the brief schedule is given below. The second low load test had a similar schedule.

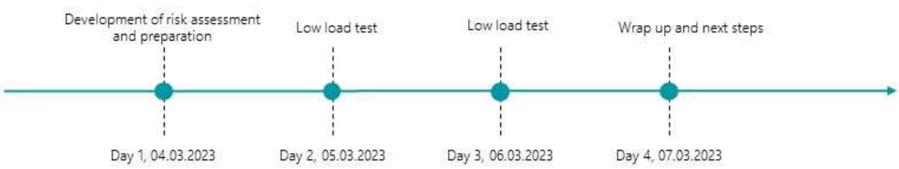

Figure 69. Plan for pilot in Raichur.

It has been agreed that, at both power plants, CEA will be present, and together with DEA and plant operators (NTPC and KPCL) perform the tests, and target the 40% of load. In addition, a request has been made to measure efficiency and NOx emissions at different (55%, 50%, 45%, 40%) load during site test.

Prior to the test execution, thorough discussions were held to determine the details and conditions. The following specific topics were presented and deliberated upon:

- Roles and responsibilities.

- Unit readiness assessment.
- Measurements and sampling protocols.
- Comprehensive planning considerations.
- Risk assessment procedures

These discussions aimed to ensure a clear understanding and consensus on various aspects related to the test, including the assigned roles and responsibilities, the preparedness of the unit, the methodology for measurements and sampling, detailed planning requirements, and the assessment of potential risks.

Additionally, based on the Danish experience, suggestions were given that the following personnel should be available at the power plants during the realization of the pilot projects:

- The person in charge/responsible for the test
- Operation responsible engineer
- C&I engineer
- Combustion engineer (if such a professional is available)
- Control room personnel that will be operating the plant during the tests
- Additional personnel required to take coal and p.f. samples during the tests (Necessary equipment for taking coal and pf. samples must be prepared)

It was suggested that, for logistic purposes, only the directly involved personnel should be present.

Development of risk assessment and preparation for the 1st low load tests

The first day of the first low load tests, the development of risk assessment and preparation for the test was discussed. During this day, the discussion was focused on experimenting with the boiler load and settings to find the best and most stable low load. The ultimate goal was to achieve 1%/min of ramp rate at lower load and the stable operation of unit at 40% of load with stepwise decrease of load and no refurbishment.

The purpose of the risk assessment is to identify potential factors that potentially pose a risk for limiting the test or tripping equipment

A number of risk assessments were proposed by Danish experts, and a summary is given in Table 8-3.

Table 8-3. The risk types, causes and mitigations discussed on the 1st day

Risk type	Risk	Causes	Mitigation
Personal injury	Injury from flame observations	Back firing can happen if furnace pressure increases beyond barometric, and observations are done through sight openings	• Use of face shields and flame-resistant clothing • Only make flame observations during stable conditions

	Injury from boiling water from furnace bottom water lock	If a furnace explosion occurs the water lock can be blown out	• No personnel allowed close to the water lock • Shielding of the surrounding area
Equipment damage	Erosion of last stage turbine blades leading to increased stresses and loss of turbine efficiency	Low RH steam temperature will increase moisture content in the turbine exhaust	• Monitor the SH and RH temperatures • Monitor condenser pressure • Monitor water level in condenser • Manually control the attemperator spray controls • Adjust firing tilting • Select “high firing” burners and mills (K) • Use soot-blowing preventive
	Turbine vibrations and displacement	The turbine will be exposed for unusual conditions which can lead to excessive vibrations and/or displacement	• Monitor the vibration and displacements by trend-curves • Adjust exhaust pressure • Close off selected turbine bleeds and preheaters
	Corrosion of Air Heaters	The flue-gas temperature will drop in lower loads exposing a risk of condensing sulphur acid on the cold Air Heater	• Increase combustion air inlet temperature by operating the Steam Air Preheaters. • Increase air bypass to the mills • Only operate with one AH • Operate with low sulphur content coals
	Water/steam side corrosion	Feed-water quality can be compromised by e.g. lower deaerator pressure	• Monitor water chemistry by ph values and Conductivity • Lab analysis of water samples
Unit trip	Loss of flame and fuel oil is not working.	Combustion instability or poor flame detection can lead to boiler trip: • Feeder out of operation • Power out of operation • Oil nozzles not proven • No flame scanners signals (3/4)	• Visual flame observations to confirm stability • Reduce no of operating mills • Adjust primary air flow • Monitor NOX and CO levels • Reduce boiler steam pressure
	Extreme drum level	If the boiler drum level is “very low” or “very high” the boiler is tripped.	• Monitor the level by trend-curve • Manually adjust the control S.P. • Monitor the feed-water flow • Operate electrical BFP
	Extreme furnace pressure	If the furnace pressure is “very low” or “very high” the boiler will be tripped.	• Monitor the furnace pressure by trend-curve • Monitor and ensure stable ID fan operation

		Pressure fluctuations are likely	• Adjust the furnace pressure S.P. • Adjust O2 S.P. • Avoid water-wall soot-blowing
	Condensate and feed-water system stability	Low condensate/FW flow can lead to system instability which can result in equipment damage or unit trip	• Monitor condensate and feed-water conditions: ○ Pump vibrations ○ Flow rates ○ Heater levels • Operate using the electric feed-water pumps • Manually operate the heater drains to control the level

In addition to the aforementioned risks, there is a number of other risks to consider:

- Mill trip
- Feeder trip
- Coal pipe fire
- Excessive SH metal temperature
- SH/RH steam temperature distribution
- Fuel Oil Burner failure
- Coal quality variation
- Low pf quality
- Insufficient pf distribution
- Insufficient PA and/or SA distribution
- Turbine gland seals failure
- Boiler circulation pump instability
- Too low steam pressure for soot-blowing
- Too low turbine BFP steam pressure

Additionally, the most important risks were discussed, and a number of discussions were held in order to achieve the goal of low load operation at 40%. A large part of discussion was related to avoiding the tripping of the unit and the number of mills needed to operate safely, and at what stages to collect the samples.

During the second low load tests, the similar preparation was followed.

Summary of the tests

The unit demonstrated its capability to achieve a 40% load using coal of relatively poor quality. Although the ramp rates were not fully met, the unit exhibited a highly favorable response during the testing period.

During the course of the works, two primary focus areas have been identified:

1. Optimizing of control loops. The test revealed that the unit control was predominantly manual, which is suboptimal as it necessitates highly skilled control room personnel. In order to enable the unit to operate in automatic mode during low loads and ramping, it is imperative to review the following control loops as a minimum:
    a. Master unit control – fuel/load coordination.
    b. SH and RH spray temperature control.
    c. Boiler drum level control.
    d. Condensate flow control.
    e. Oxygen control and fuel/air coordination.
    f. Flue gas temperature control using SCAPH.
    g. Ramping control. Automated start-up and shut-down of mills.

2. Coal dust distribution optimization. The distribution of coal dust among the individual coal pipes, from the coal mill to the burners, exhibited an unacceptable deviation, reaching up to 47%. This issue must be thoroughly investigated and addressed in order to mitigate its impact. The significant deviation observed in the coal distribution could potentially be attributed to the roping phenomenon. It is recommended to conduct a more in-depth investigation into this matter and consider engaging BHEL for a comprehensive analysis.

It is preferable to complete the control loops mentioned in item 1 before proceeding with the optimization of the coal dust distribution in item 2. By completing the control loops first, any necessary adjustments or corrections can be made to ensure stable and reliable operation. Once the control loops are in place and functioning effectively, it is then appropriate to focus on optimizing the distribution of coal dust to achieve the desired results. This sequential approach helps to ensure that the necessary control measures are in order before fine-tuning the coal dust distribution.

It's worth noting that unlike the coal dust distribution, the dust fineness was found to be nearly in compliance with the design presumptions. This indicates that the size of coal particles meets the desired specifications, and further adjustments in this regard may not be immediately necessary.

Among the coal mills, Mill "D" stands out due to its prominent characteristics of higher loading, poor dust distribution, and elevated differential pressure.

The Steam Air Preheaters (SCAPH) were not operational, and the flue gas temperature became uncontrollable. It poses challenges, particularly when low loads are expected to become a regular occurrence. In such cases, it will be necessary for the SCAPH to have the capability to raise the flue gas temperature above the sulfur dew point for avoiding corrosion in the air preheaters. By increasing the flue gas temperature beyond the sulfur dew point, the SCAPH can mitigate issues related to sulfur condensation.

Maintaining the primary air (PA) bypass dampers is essential to ensure their ability to effectively close off cold PA leakages. This is particularly important when dealing with wet coals, as preventing cold air from bypassing the system is essential for achieving proper coal drying and combustion efficiency.

The flue gas oxygen content was deliberately high. The aim was to be confident that the secondary air distribution was controllable. To enhance efficiency, it is advisable to identify a lower level of oxygen in the flue gas, as the intentional high level was primarily intended to regulate the distribution of secondary air.

Throughout both tests, there were noticeable fluctuations in flame intensity levels, often accompanied by intermittent flickering. These observations are likely related to the previously mentioned issues, such as problems with pulverized fuel (PF) distribution, insufficient fineness, the absence of PF dry-out, and the possibility of roping. However, it's also possible that the problem could be associated with the flame scanner itself. Therefore, we recommend conducting a thorough verification process of the flame scanner signals to pinpoint the exact cause of these fluctuations.

In the first test, the condenser system exhibited relatively high pressure, which, combined with the non-functioning sub-atmospheric condensate preheaters, indicates the occurrence of air entrainment within the vacuum system. This increased pressure is responsible for a reduction in efficiency of approximately 2 percentage points or a decrease in power output of around 5 MW.

We suggest that the next phase of the flexibilisation process should prioritize the enhancement of control loops and coal dust distribution. The implementation of control loops requires careful attention and extensive testing before integration into the DSC system.

To effectively address the PF distribution issue, we recommend involving BHEL in both the planning and implementation phases. It is central for this process to begin promptly to ensure that the new equipment is prepared for installation during the next scheduled maintenance outage. This will expedite the resolution of the problem.

After the successful completion of this phase, further testing will be necessary to assess the achieved enhancements and determine if any additional upgrades are required, such as dynamic classifiers, to further improve the system's performance

8.2.2.1. Planning of the tests

The second and third day, the low load test were performed where the key indicators needed to observed and measured were efficiency/heat rate of unit at different loading, effect of low operation on NOx emissions and water consumption (55%, 50%, 45%, 40% load), CO2 emissions and other parameters and Log book.

During the second day, there was a discussion on the ramp rate and a draft document where new ramp rates are proposed from CEA as follows:

- 3%/min from 70% to 100% of the maximum capacity
- 2%/min from 55% to 70% of the maximum capacity
- 1%/min from 40% to 55% of the maximum capacity.

As mentioned, the Central Electricity Authority has been present to validate the recent 2023 government regulation for achieving 40% load operation of coal fired power plants, presented at the G20 in Delhi.

The main idea for the schedule for the testing at Raichur is provided below.

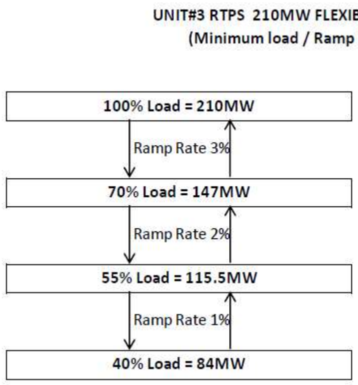

Figure 70. The schedule for testing.

As a part of planning, a plan for the low load test had to be developed for both days and sent to SRLDC (and SLDC) a day before the day of the test.

As a part of the planning process, a schedule for the low load test were developed for both days and sent to SRLDC (and SLDC) a day before the day of the test.

Before the test, the following actions were required by the power plant personal to be executed:

- Soot blowing
- De-ashing/bottom ash
- Coal mills reject boxes emptied
- Cleaning of flame scanners

1st test day

The plan for the 1st day test was presented to the power plant team the day before the actual test. The concept of the test was to reach 40% load in a safe and controlled manner in order not to take any risk that could eventually impede the objective.

- 5/3: 9 am. 67% load (140 MW) 4 mills CDEF.

  30/8: 130 MW at 9 am. Mills ABDEF. Problems with bunker C outlet pipe getting choked.

- 5/3: 10:30. 57% load (120 MW) 3 mills CDE.

  30/8: 10:25, 165 MW, mill C back in service. Mills BCDE.

- 5/3: 12:30. 45% load (94.5 MW) 3 mills CDE.

  30/8: Load reduction to 114 MW at 11:46 am. Mills BCDE.

- 5/3: 13:20. 40% load (84 MW) 2 mills CDE.

  30/8: 40% load with 3 mills CDE at 13:30 am.

- 5/3: 16:20. The load was ramped up to 180 MW

Initially during the first test, it was proposed to run the plant at 40% load with only two coal mills operating, but this idea was dismissed by the plant due to safety concerns i.e. the unit has never been operated like this before. The reasoning behind this was that if one coal mill were to trip, the likelihood of tripping the boiler would be lower if three coal mills were operational instead of two. The test was operated with “CDE” mills, and without the topmost “F” mill.

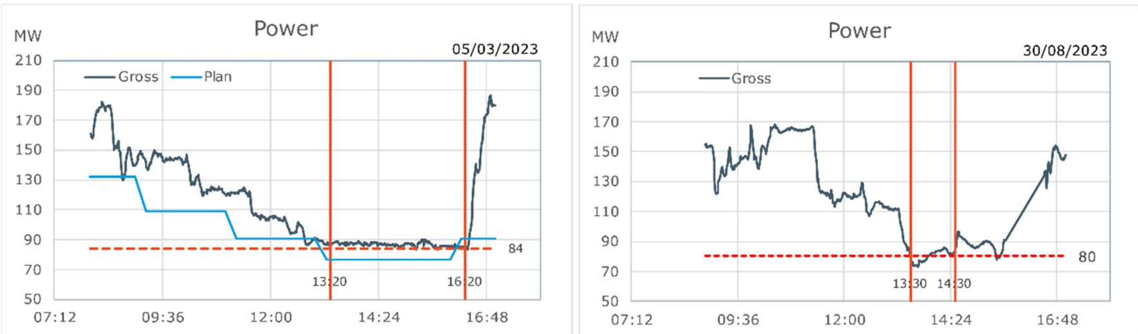

Figure 71. The load progress on 1st test day.

At the first test (5/3) the unit successfully reached 84 MW (40%) at 13:20 and maintained the load for ca. 3 hours without any serious challenges.

The second test (30/8) reached 80 MW at 13:30 and remained at this load for 1 hour.

Samples of raw coal, coal dust and UBC was taken during the test, at:

- 5/3: 9:45, 12:10 and 14:30
- 30/8: between 10:30 and 14:00

2nd test day

The 2nd test day (Marts 6th) was reserved for ramp rate tests.

1st test March 6th

The load was planned to be brought down to 40% in three individual steps while demonstrating the ramp rates, likewise the ramp rates was demonstrated while increasing load. In lower loads, the same mill configuration "CDE" as the 1st test day was applied.

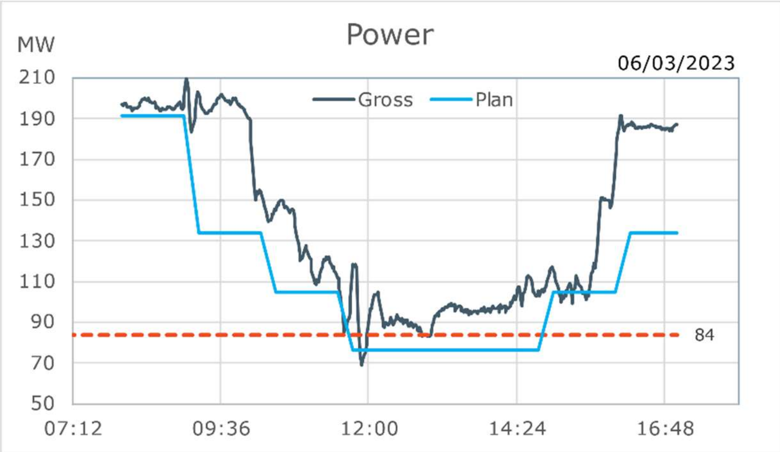

Figure 72. Load progress 2nd test day.

2nd low load test August 31st

The coal quality was even lower than the previous day. The flames were unstable, and intensities were low. Oil guns were brought into operation at level 4 to prevent tripping. At approximately 11 am, a unanimous decision was made that it was not feasible to carry out the planned ramp test.

As an alternative, two tests were agreed upon to assess their impact on flame intensity:

1. Varying the air/coal ratio.
2. Increasing classifier recirculation.

In retrospect, the coal quality analysis contradicts the combustion observations, i.e. the coal quality was, if not better, at least as good as the first test day.

Sampling

During the stabilization periods, raw coal and pulverized coal dust were sampled. Raw coal was obtained from the feeders, and dust samples were collected from each coal pipe in operation. The collected dust samples were sieved into three sizes: 75, 150, and 300 microns. Additionally, samples of bottom and fly ash were collected and analyzed for the presence of unburnt carbon (UBC).

Coal quality

The proximate coal quality was analyzed by the plant's laboratory:

Table 8-4. Raw coal analysis.

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
FLEXIBLE OPERATION OF UNIT-3
FEEDER COAL(STATION COAL) ANALYSIS REPORT

Sl. No	Date of sample collection	Sample collection at load	Timing in Hrs	UNIT	TM%	IM%	VM%	ASH % (adb)	ASH% (arb)	GCV Kcal/Kg (adb)	GCV Kcal/Kg (arb)
1	05.03.2023	195MW	9.30 TO 9.45	3	9.11	4.01	20.24	48.75	46.16	3234	3062
2	05.03.2023	100MW	11.55 TO 12.10	3	10.56	5.41	23.03	42.18	39.88	3685	3484
3	05.03.2023	85MW	2.20 TO 2.30	3	10.49	5.96	22.33	44.37	42.23	3469	3302
					10.05	5.13	21.87	45.10	42.76	3463	3283

Sl. No	Date of sample collection	Sample collection at load	Timing in Hrs	UNIT	TM%	IM%	VM%	ASH % (adb)	ASH% (arb)	GCV Kcal/Kg (adb)	GCV Kcal/Kg (arb)
1	06.03.2023	197MW	9:10 TO 9:30	3	9.60	6.74	23.99	38.56	37.38	3904	3784
2	06.03.2023	100MW	12:12 TO 12:20	3	11.74	6.75	22.53	41.76	39.53	3686	3489
					10.67	6.75	23.26	40.16	38.45	3795	3637

Sl. No	Date of sample collection	Sample collection at load	Time of collection	UNIT	TM%	IM%	VM%	ASH % (adb)	ASH% (arb)	GCV Kcal/Kg (adb)	GCV Kcal/Kg (arb)
1	30.08.2023	163 MW	10:30 to 10:45	Unit-3	11,01	5,06	23	50,61	47,44	3223	3021
2	30.08.2023	120 MW	11:30 to 11:45		10,91	5,19	23,29	50,26	47,23	3218	3024
3	30.08.2023	109 MW	12:40 to 12:55		10,71	4,64	21,81	53,39	49,99	2994	2803
4	30.08.2023	73 MW	13:35 to 13:50		10,55	4,65	21,5	53,49	50,18	2956	2773
			AVERAGE		10,80	4,89	22,40	51,94	48,22	3098	2949

Sl. No	Date of sample collection	Sample collection at load	Time of collection	UNIT	TM%	IM%	VM%	ASH % (adb)	ASH% (arb)	GCV Kcal/Kg (adb)	GCV Kcal/Kg (arb)
1	31.08.2023	132 MW	09:40 to 09:55	Unit-3	11,66	5,6	22,48	50,48	47,24	3235	3027
			AVERAGE		11,66	5,60	22,48	50,48	47,24	3235	3027

The abbreviations translate to:

adb:	Air dried (inherent moisture)
arb:	As received
TM:	Total moisture
IM:	Inherent moisture
VM:	Volatile matter
GCV:	Gross Calorific Value

The fixed carbon (FC) content can be found by difference: FC = 100 – TM – VM – ASH.

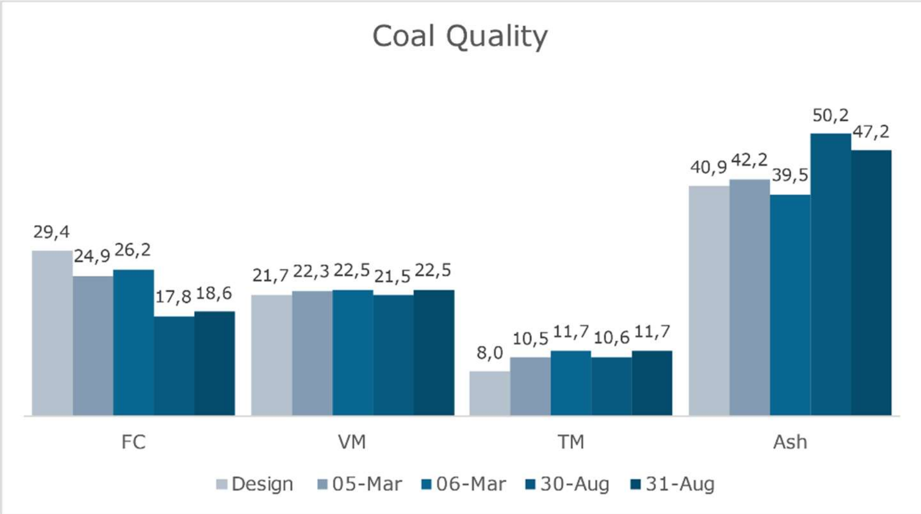

Figure 73. Coal quality during test versus design.

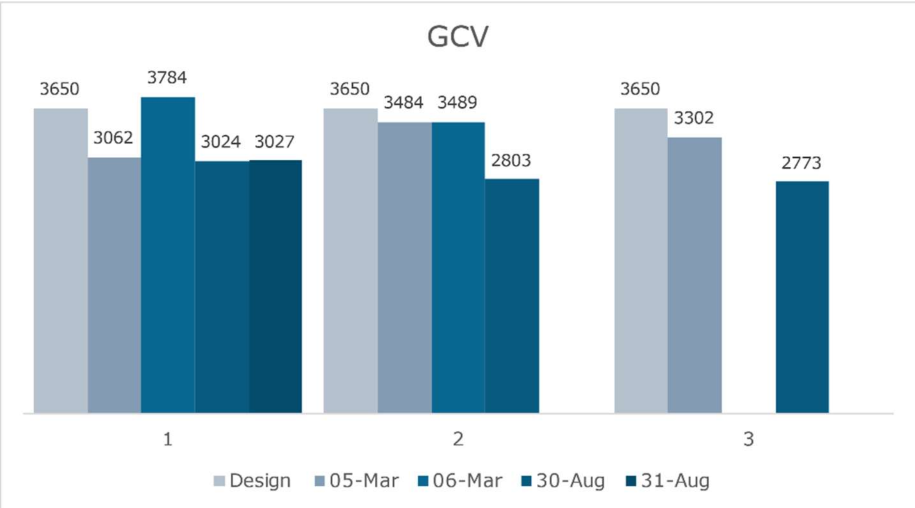

Figure 74. Coal GCV during test versus design.

The ultimate analysis of the coal was performed by Central Power Research Institute (CPRI) can be found in the appendix.

On this basis the following fundamental analysis for the low load test, on wet as received basis, can be derived:

Table 8-5 Ultimate coal analysis.

Ultimate analysis		05/03/2023	30/08/2023
GCV	kcal/kg	3302	2773
LHV	MJ/kg	12,94	10,71
Carbon	%	31,8%	25,0%
Hydrogen	%	2,7%	2,8%
Sulfur	%	0,4%	0,5%
Oxygen	%	11,8%	10,4%
Nitrogen	%	0,6%	0,5%
Water	%	10,5%	10,6%
Ash	%	42,2%	50,2%
SUM	%	100,00%	100,00%

It is notable that the expected low quality coal in the 2nd test (30/8) cannot be attributed to the moisture content; instead, it is primarily due to an exceptionally high ash content. Furthermore, it is essential to underline that the unit is designed for coals within the quality range of a Gross Calorific Value (GCV) between 3650 to 3500 kcal/kg and a maximum ash content of 40%.

8.2.2.2. Main performance data (averaged)

The main test data is show in below table. For convenience “Unit 3 Data Sheet Design” (predicted performance) for 60% load is also shown. The measurements are averaged, in the most stable timeslot available. Some measurements were out of order, especially “O_2 APH outlet B”.

Table 8-6. Averaged measurements.

Time	Unit	Design 60%	5/3 2023 15:40-16:23	6/3 2023 12:49-13:01	30/08/2023 13:30-14:30
Unit load	%	60%	40,6%	40,0%	38,1%
Unit load	MW	126	85,3	84,0	80,0
Coal flow (measured)	t/h	84	70,6	65,0	89,7
Coal GCV/HHV (arb)	kcal/kg	3650	3302	3489	2773
- fixed carbon	%	29,4	25,0	26,2	17,8
- moisture	%	8	10,5	11,7	10,55
- ash	%	40,9	42,2	38,5	50,2
- volatiles	%	21,7	22,3	22,5	21,5
Steam flow	t/h	376	267,3	263,1	261,7
SH spray	t/h	34	10,3	6,5	3,0
RH spray	t/h	0	2,7	3,0	7,7
Feedwater temperature - ECO	°C	218	202,9	202,3	202,4
SH temperature - left	°C	540	542,0	538,8	536,1
SH temperature - right	°C	540	539,1	536,0	550,2
CRH temperature -1	°C	325	351,0		357,8
CRH temperature -2	°C	325	326,9		320,2
HRH temperature -1	°C	540	543	536,4	528,5
HRH temperature -2	°C	540	535	533,2	516,1
O_2 APH inlet - A	%	4,99	NA	NA	8,3
O_2 APH inlet - B	%	4,99	8,65	9,4	9,3
O_2 APH outlet - A	%	-	10,87	10,7	12,0
O_2 APH outlet - B	%	-	6,8	6,54	NA
FG outlet temperature APH-A	°C	118	125,6	124,9	124,0
FG outlet temperature APH-B	°C	118	120,8	120,2	117,3
FD fan-A outlet temperature	°C	35	43	42,8	42,5
FD fan-B outlet temperature	°C	35	35,8	36,2	36,4
PA temperature APH-A outlet	°C	296	-	-	271,3
PA temperature APH-B outlet	°C	296	-	-	-
SA temperature APH-A outlet	°C	292	276,5	279,2	272,2
SA temperature APH-B outlet	°C	292	64	64	257,9
Feeder C coal flow	t/h	28,0	22,2	19,8	33,2
Feeder D coal flow	t/h	28,0	26,0	23,3	30,9
Feeder E coal flow	t/h	28,0	22,1	21,8	26,2
PA flow to mill C	t/h	55,0	61,1	59,3	60,6
PA flow to mill D	t/h	55,0	63,5	63,1	60,7
PA flow to mill E	t/h	55,0	60,8	59,8	62,2
PA temperature to mill C	°C	222	181	193	274
PA temperature to mill D	°C	222	255	221	250
PA temperature to mill E	°C	222	182	183	243
PA temperature from mill C	°C	65-95	75,3	69,4	64,0
PA temperature from mill D	°C	65-95	79,8	71,2	77,9
PA temperature from mill E	°C	65-95	75,0	73,6	76,9
DP mill C	mmWC	377	329	283	380
DP mill D	mmWC	377	512	508	524
DP mill E	mmWC	377	149	146	198
Current mill C	amps	-	36,5	36	40,4
Current mill D	amps	-	38,3	38,5	37,7
Current mill E	amps	-	33,1	32,9	34
Total air	t/h	549	530	579	531
Main steam pressure - left	KSC	150,8	115,5	116,6	94,8
Main steam pressure - right	KSC	150,8	115,3	116,9	95,3
Drum pressure	KSC	154,3	118,0	119,3	97,6
CRH steam pressure - left	KSC	22,1	16,15	16,2	15,5
CRH steam pressure - right	KSC	22,1	16,31	16,3	15,5
HRH steam pressure - left	KSC	21,2	15,21	15,2	14,5
HRH steam pressure - right	KSC	21,1	15,2	15,2	14,5

Flame intensities

The flame intensities are measured between each burner level in each corner. The flame intensities are shown in figures below for first day of 1st and 2nd low load tests.

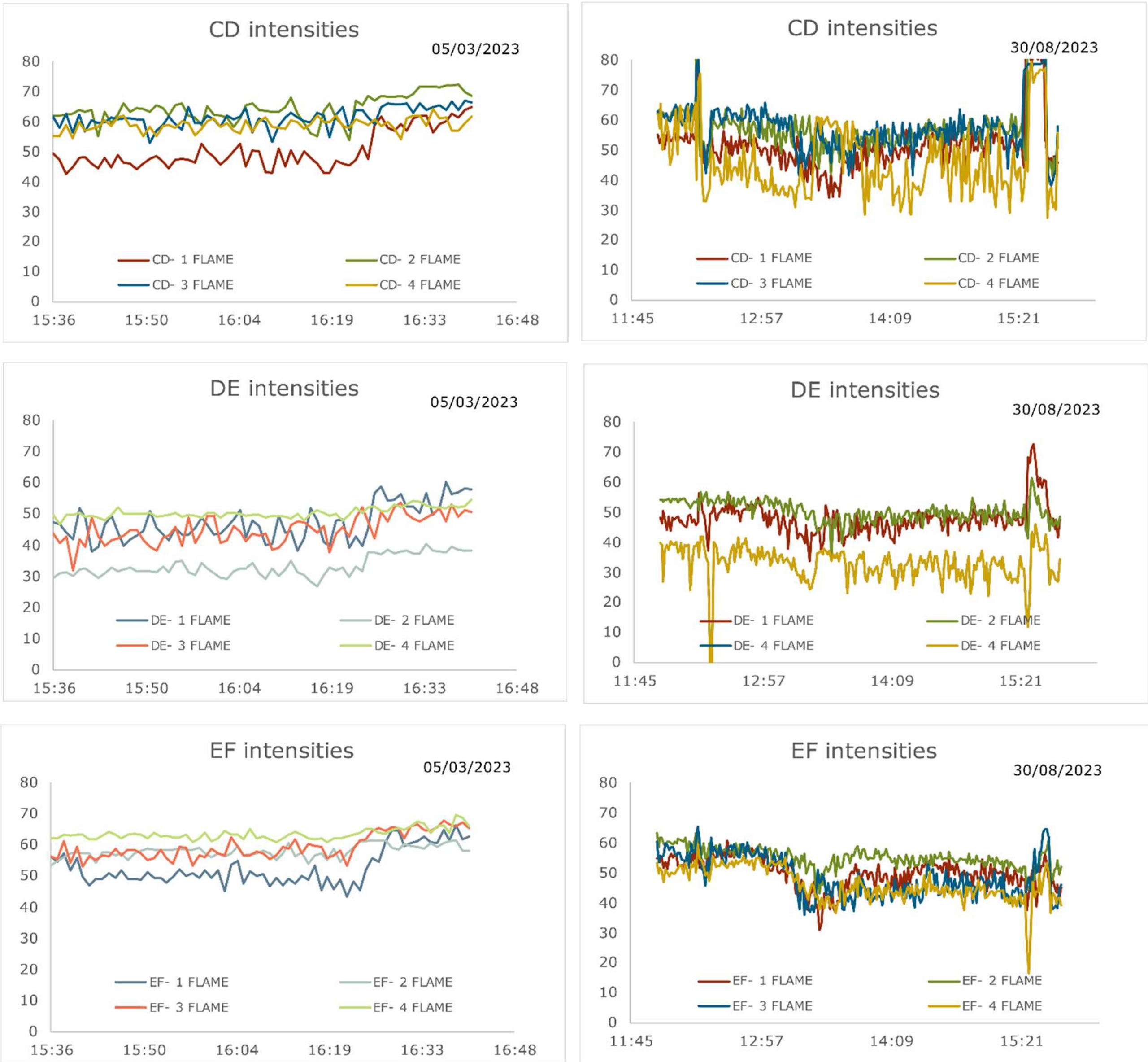

Figure 75. Flame intensities.

Coal dust samplings

The samplings from the Plant's laboratory are found in the appendix. Sample weight distribution and averaging the samples is shown below for the low loads of both tests.

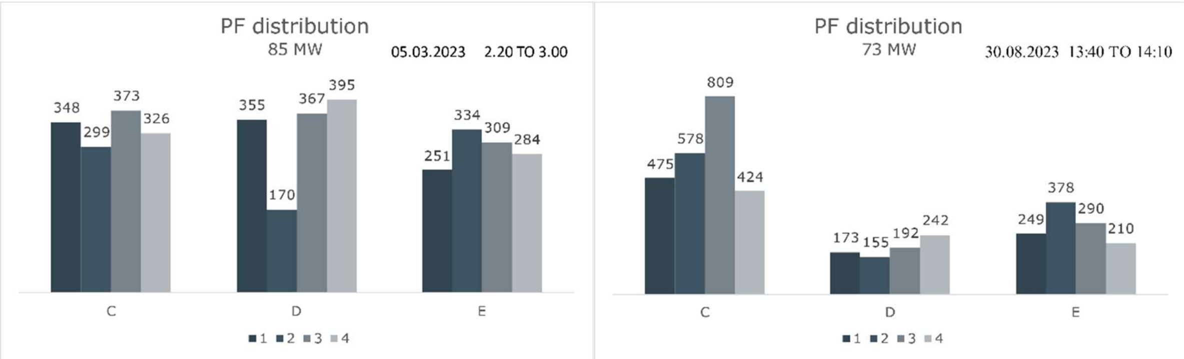

Figure 76. Sample weight distributions.

To ensure clarity regarding the quality of the samples, it is important to provide detailed descriptions and tolerances of the sampling equipment. Additionally, it may be helpful to outline any specific tolerances or acceptable variations in the sampling process to maintain consistency and accuracy in the collected samples.

For optimal results, it is recommended to collect coal dust samples using an isokinetic sampler, following the guidelines outlined in ISO 9931.

Sieve tests

The lab analysis can be found in the appendix. The data is presented as the percentage of coal dust remaining on the sieve after screening.

According to design data, the requirement is 70% through a 200 mesh (75 microns), or 30% as the remainder. The coal dust sieve tests for both 1st and 2nd low load tests are given in below figures.

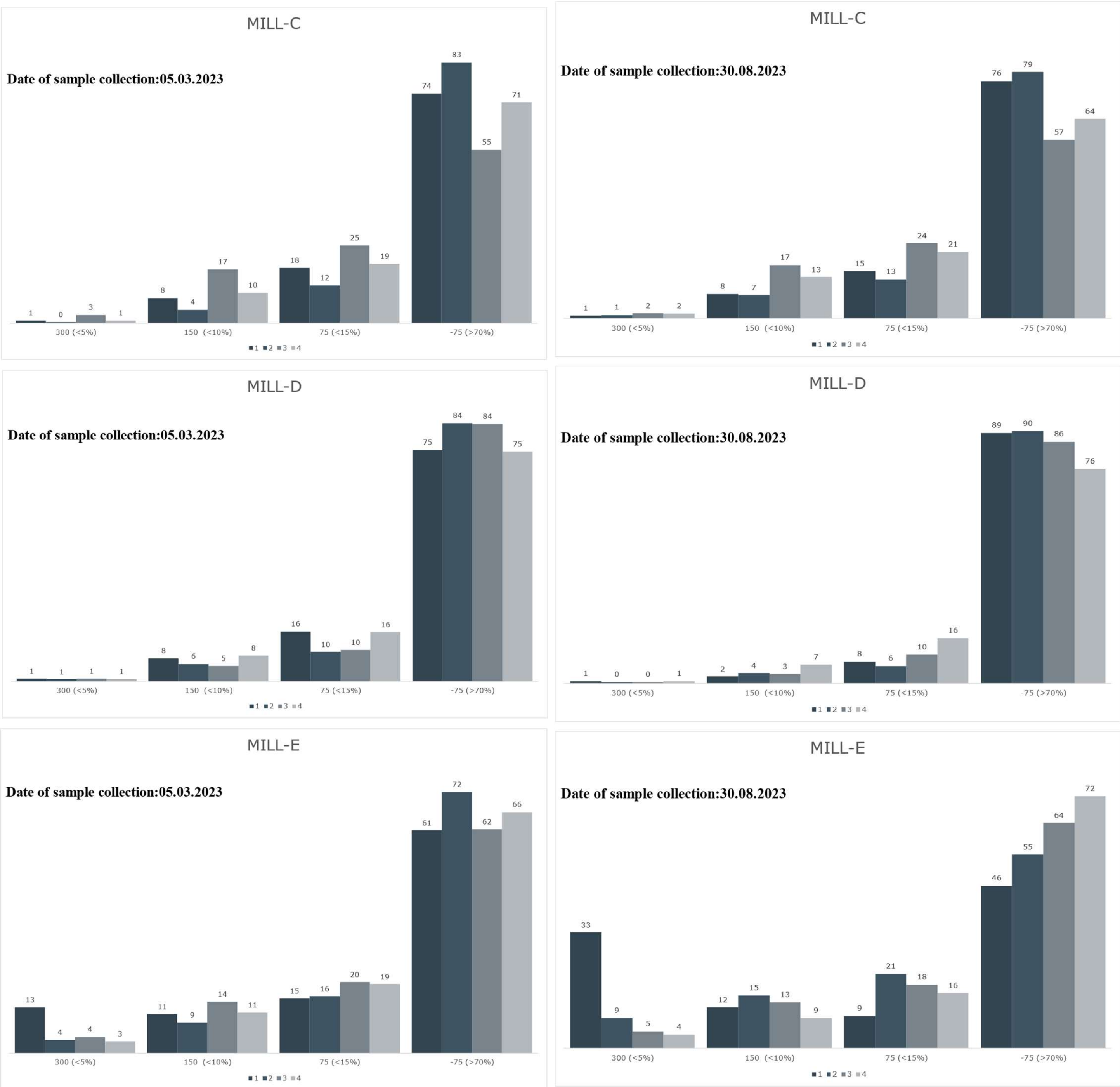

Figure 77. Coal dust distribution (Test-1).

8.2.2.3. *Observations during 40% low load*

Coal mills

The coal mills are designed for a max. coal flow of 36 tons/hour while the nominal 100% flow is 34.4 tons/hour. According to the "predicted Performance" by BHEL, the designed outlet temperature is expected to fall within the range of 65 to 95°C, while the design fineness is 70% through a 200 mesh. The air-coal ratio is predicted to ca. 1.96 at 60% unit load and 81% mill load, based on design coals.

Mill Load

Figure 78 below, provide the coal mill loads for the 1st test day during both 1st and 2nd low load tests.

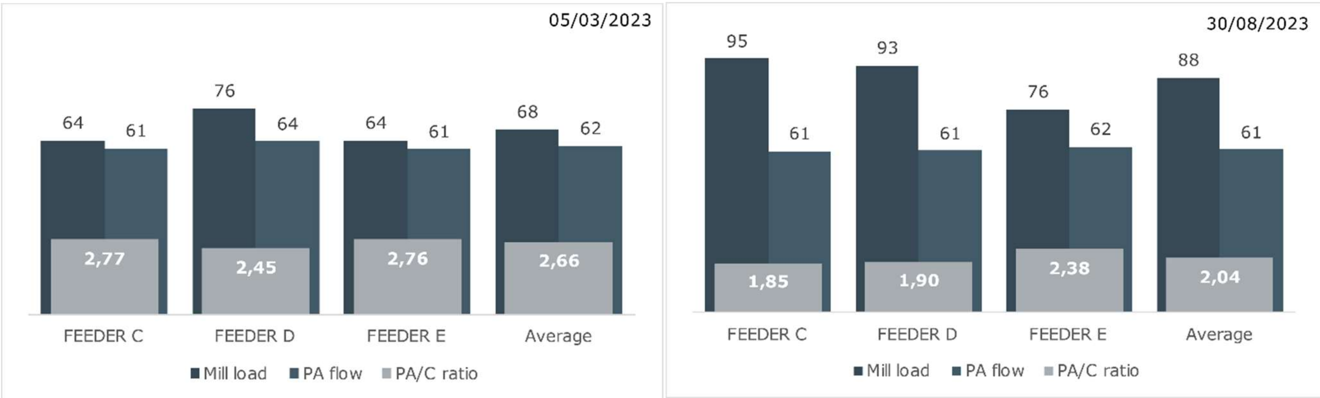

Figure 78. Coal mill loads (5/3 and 30/8).

1st low load test 5-3-2023

During the low load three mills "CDE" were in operation and the mass loads were in average 68%.

Mill "D" was loaded ca. 11% higher than "C" and "E". The flame intensity for level "DE" is ca. 10% lower than level "CD" and "EF". It's worth noting that the air-coal ratio appears to be unreasonably high, exceeding the expected ratio of ca. 2.2. The air control was handled manually which explains the high ratio.

The average mill load of 68% is undesirable low as it has a negative influence on the flame stability. If only two mills were in operation, the average mill loads would rise to approximately 35.1 t/h, equivalent to 102%. This would lead to an undesirably high load and an increased risk of tripping. As a result, operating with two mills at low load would only be feasible in very rare cases where high-quality coal is accessible. If operated with lower quality coals, the mill load will increase and compensate somewhat for the coal quality.

2nd low load test 30-8-2023

In the second test, the mill load was notably higher by 20% due to the lower quality of coal. The distribution of mill loading was quite uneven, with the lower-loaded mill supplying the upper burner level. Although the air-coal ratios were considerably lower compared to the first test, they still remained slightly above the nominal curve.

- The PA flow should optimally be controlled by the DCS system and follow the nominal curve.

Mill Outlet Temperature

In

Figure 79, mill outlet temperatures are shown for the 1st test day during both 1st and 2nd low load tests.

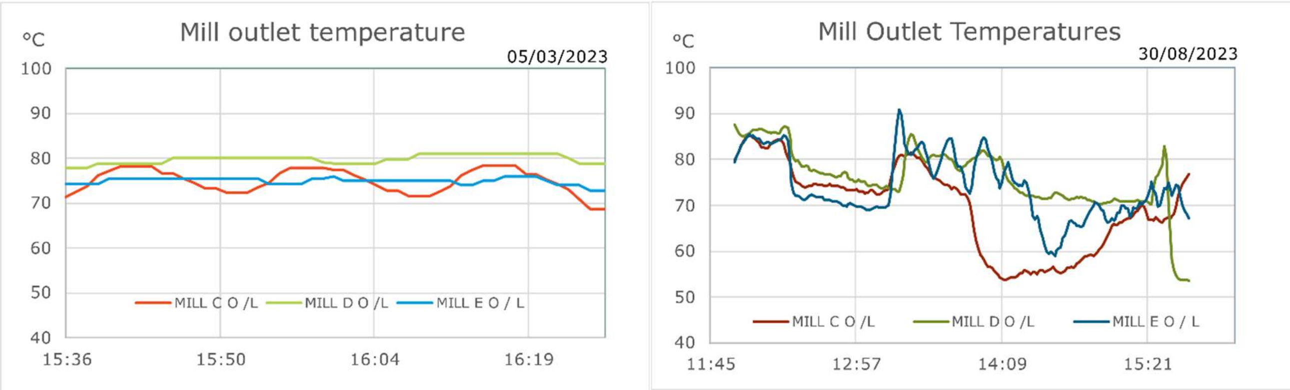

Figure 79. Mill outlet temperatures.

1st low load test 5-3-2023

An average mill outlet temperature of approximately 77°C was achieved through manual adjustment. However, this resulted in increased cold bypass and, ultimately, a higher APH outlet flue gas temperature. Conversely, a higher flue gas temperature compromises efficiency.

The outlet temperature of mill "C" is fluctuating app. 6°C with a very regular frequency. Compared to the PA flow, it is evident that the flow and temperature controls both needs optimizations.

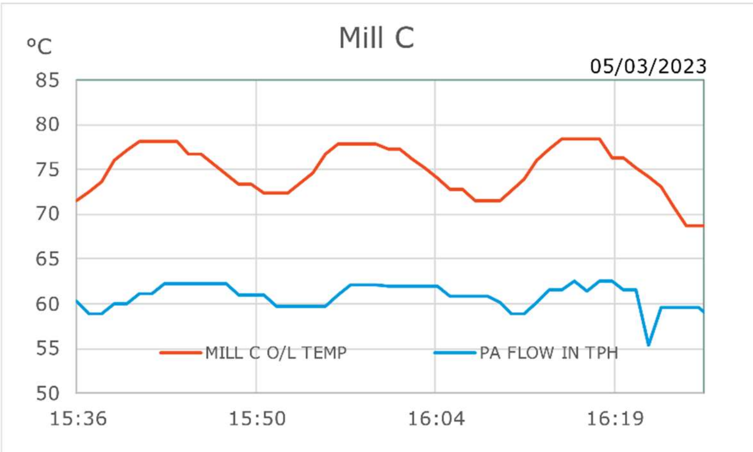

Figure 80. Mill C data.

2nd low load test 30-8-2023

From

Figure 79; the temperature fluctuations, specifically for mill “C” and “E”, ranging from 54 to 91°C, is considered excessive. It is suspected that this variation stems from varying inlet temperatures and uneven pf. distribution as well as elevated moisture in both coal and combustion air. However the control system should be capable of maintaining the temperatures within a defined range.

- The mill outlet temperature shall be as high as possible to increase efficiency.
- The PA-temperature and PA-flow controls needs to be optimized.

Mill Inlet Temperature

Mill inlet temperatures are shown for the 1st test day during both 1st and 2nd low load tests in below figure.

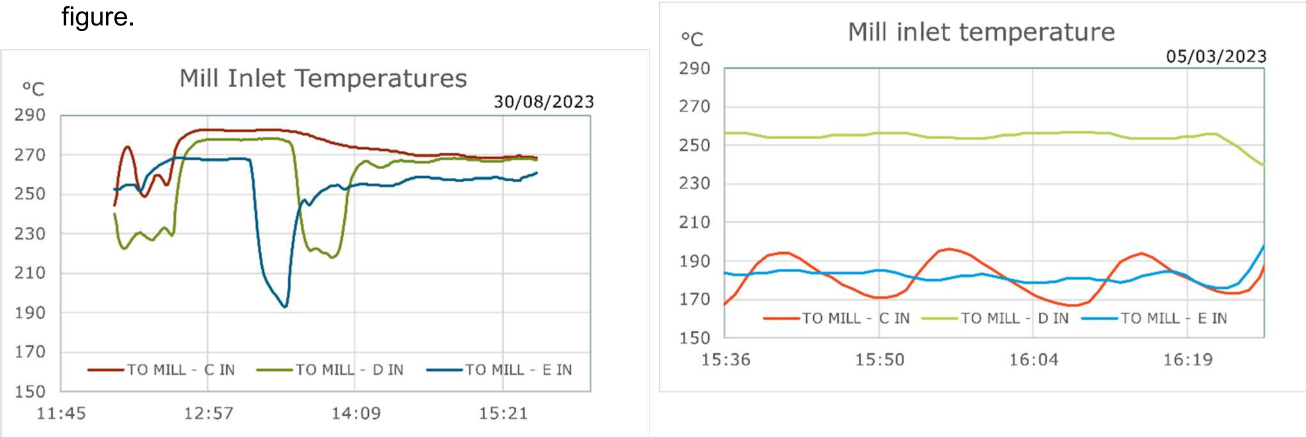

Figure 81. Mill inlet temperatures

1st low load test 5-3-2023

The harmonic pattern as seen in the outlet temperatures are also evident in the inlet temperatures. The significant difference between mill "D" and mills "C" and "E" can only be attributed to variations in milling quality. Mill “D” requires ca. 255°C, 60°C higher than both mill “C and “E”, even considering the higher mill load it’s obvious that mill “D” is performing quite different than mill “C” and “E”.

2nd low load test 30-8-2023

The problem with controlling the temperatures is evident, as seen in Figure 82. The outlet temperature reached the max temperature 90°C, triggering the controls to open the cold bypass in order to cool the inlet temperature and then dropping ca. 70°C. This situation serves as an example of a control system that should be optimized to prevent excessive temperature fluctuations.

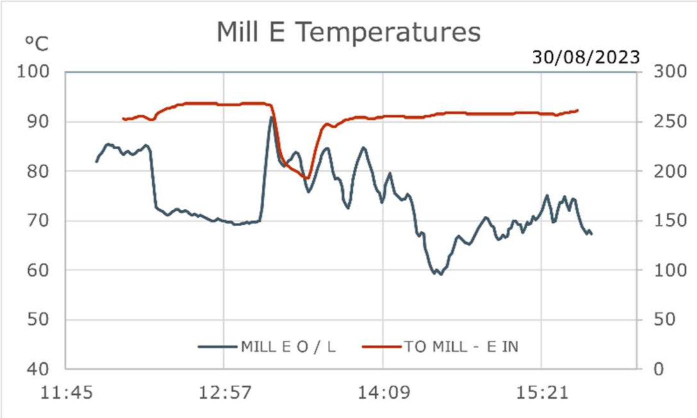

Figure 82. Mill E in- and out temperatures.

Raising the mill's outlet temperature from 90 to 100°C can reduce the relative moisture in the combustion air by around 30%, leading to a notable enhancement in the drying process. Additionally, a 1% increase in coal moisture content requires an approximate 15°C higher primary air (PA) inlet temperature to attain the same degree of dryness.

- *When using moist coal during the rainy season, it may become necessary to increase both the inlet- and the outlet temperature of the mill to achieve the necessary drying effect. Elevated moisture levels in both the combustion air and coal impede the overall drying process.*

Increasing the mill temperature from 90 to 100°C comes with certain potential risks, including the risk of fire. It is advisable to seek consultation with the OEM (BHEL) before implementing such measures to ensure safety and proper guidance.

To raise the inlet temperatures effectively, it's central that the air preheater (APH) cold bypass can be fully closed. However, during the second test, there were difficulties in achieving this because the dampers were requested to close but were unable to do so due to damper leakages. This issue with damper leakages can hinder the control of inlet temperatures and impact the overall combustion process. It is suggested that this issue is addressed during the normal maintenance outage.

Feeder Speed

The feeders are designed for a capacity between 10.8 and 39.6 t/h. While operating in the 40% low load the average feeder load was comfortably in the range of 60% in the first test, and between 66 and 84% in the second test.

Differential Pressure

The pressure differential is designed for 406 mmWC, presumable, at design flow 36 t/h.

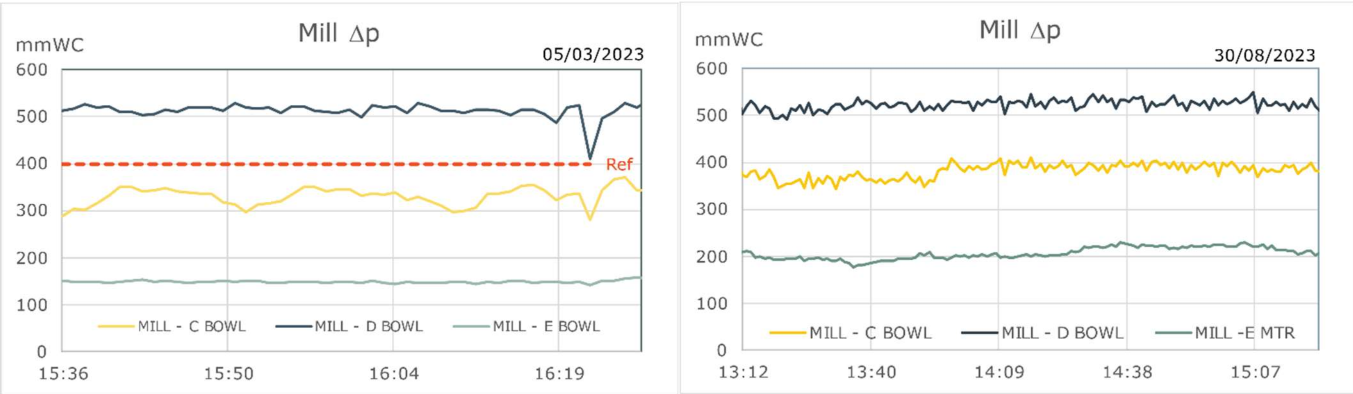

Figure 83. Mill differential pressure.

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Mill “D” was drawing 512 mmWC in average, while mill “C” was drawing 329 and mill “E” only 149 mmWC. Because of the higher mill load the pressure loss, of mill “D”, is expected to be higher with a factor proportional to the load ratio: $(76/64)^2 = 1.41$, i.e. 512/1.41 = 363 mmWC for mill “C” and “E”. Compared to the reference pressure loss, the pressure losses are much too high.

2nd low load test 30-8-2023

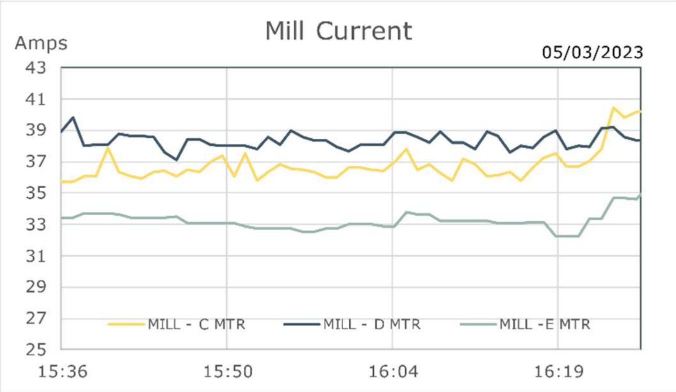
The same pattern as from the first test can be recognized. The pressure losses in the mills can primarily be attributed to three factors:

1. Throat ring velocity
2. Filling of the mill
3. Outlet losses

It is recommended to thoroughly inspect the mills for potential internal faults. Regular visual inspections should be carried out to assess the condition of internal components, checking for signs of wear and tear. As part of routine maintenance, it is essential to replace any worn-out or damaged internal components, including grinding elements, bearings, and seals.

Mill Motor

The mill motors are designed for 340 kW, 6.6 kV and 44.1 Amps. It is possible to measure the mill currents.



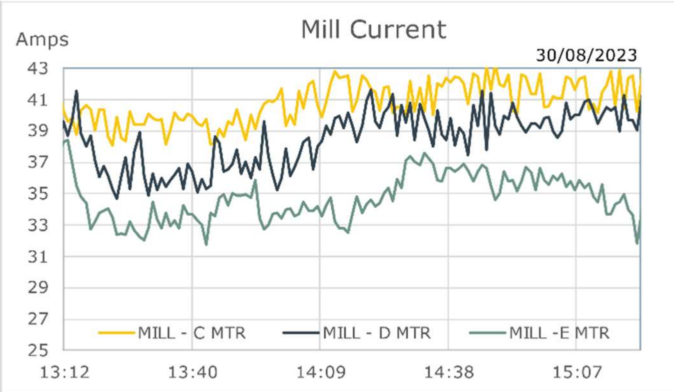


Figure 84. Mill current.

1st low load test 5-3-2023

In average mill "D" was drawing 38.3, mill "C" 36.5 and "E" 33.1 Amps. The same pattern as for the pressure losses can be observed here. As anticipated, mill "D" exhibits a higher current compared to both mill "C" and "E," which were expected to draw the same current based on the mill loadings.

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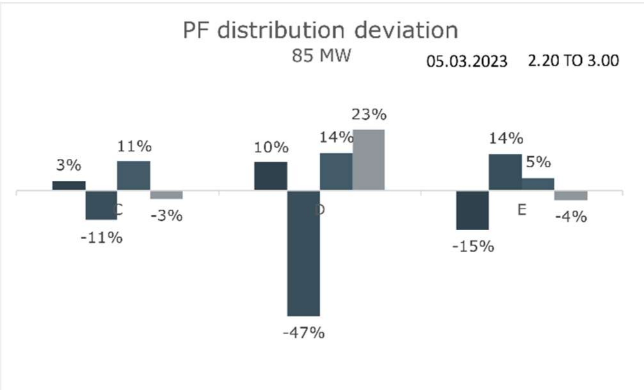
Mills "C" and "D" are as expected drawing ca. the same current (38 and 40 amps) in the low load time frame between 13:30 and 14:30, while mill "E" is drawing a little lower current which is as expected according to the mill loadings.

Coal Dust Distribution

The distribution between the individual coal pipes should optimally be within a range of app. +/- 5%

1st low load test 5-3-2023

Mill "D" stands out with a significant deviation ranging from -23% to +47%, which has a major impact on combustion efficiency. This effect is also noticeable in the flame intensities and in the pressure difference.



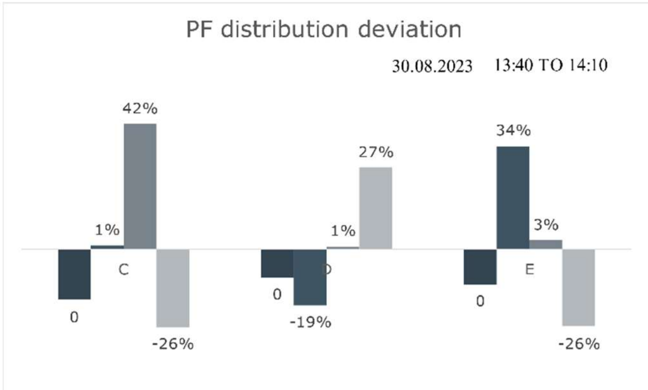


Figure 85. PF distribution deviation.

2nd low load test 30-8-2023

All mills exhibit excessive distribution deviations from -26% up 42%.

Overall, based on the testing, the following finding should be taken into consideration:

- The pf. distribution needs to be optimized.

Overview, optimization and balancing of coal dust

In the following, a summary of the coal dust optimization and balancing is given based on the finding.

Balancing the coal dust output from a coal mill is a well-known problem for thermal power plant operations. The issue primarily arises due to several factors:

1. Variability in Coal Properties: Coal quality can vary significantly, even within the same batch of coal. Differences in moisture content, particle size distribution, and calorific value can lead to uneven combustion and, consequently, uneven coal dust output.

2. Mill Wear and Tear: Over time, coal mills experience wear and tear, which can result in uneven grinding of coal. This can lead to variations in coal dust output as the mill components degrade.

3. Mill Load Fluctuations: Changes in the load on the power plant can affect the operation of coal mills. Sudden load changes can disrupt the balance of coal flow within the mill, causing fluctuations in coal dust output.

4. Classifier and Vane Settings: The settings of classifiers and vanes within the coal mill play a central role in determining the fineness and distribution of coal dust. Incorrect settings can lead to imbalances in coal flow and output.

5. Environmental Impact: Imbalanced coal dust distribution can lead to uneven combustion in the boiler, potentially causing emissions of pollutants and reduced thermal efficiency. This can result in environmental compliance issues and operational inefficiencies.

To address these issues and achieve better pf. balance, various strategies can be applied:

- Regular Maintenance: Scheduled maintenance and inspection of coal mills are critical to detect and rectify wear and tear issues promptly.

- Coal Quality Control: Implementing stringent coal quality control measures, including coal sampling and analysis, helps ensure consistent fuel properties.

- Optimal Mill Settings: Properly configuring mill and classifiers parameters to match the coal characteristics and load conditions is essential for achieving balance.

- Load Management: Employing load-following strategies and control systems can help mitigate the impact of load fluctuations on coal dust output.

- Monitoring and Control Systems: Utilizing advanced monitoring and control systems can provide real-time data on mill performance, facilitating timely adjustments.

Balancing coal dust output is vital not only for maintaining combustion efficiency but also for minimizing environmental impact and ensuring the overall reliability of thermal power plants.

Adjustable orifices or valves can be valuable components in addressing the issue of balancing coal dust output from coal mills in thermal power plants.

- Flow Control: The equipment can be strategically placed within the coal dust distribution system to regulate the flow of coal dust from the mill to various burners.
- Fine-Tuning: The equipment allows for fine-tuning of the coal dust flow. By controlling the flow rate to individual burners, the combustion can be optimized reducing the risk of incomplete combustion or high emissions.
- Monitoring and Feedback: Advanced control systems can be equipped with monitoring and feedback mechanisms that continuously assess the performance of adjustable orifices and valves. This data can be used to make real-time adjustments, ensuring optimal coal dust distribution.
- Maintenance and Reliability: Regular maintenance and inspection of these components are critical to ensure their reliability. Properly maintained adjustable orifices and valves can continue to function effectively in maintaining coal dust balance.

The analysis indicates a possible problem with the “roping” phenomenon, which needs to be analyzed in more details.

Roping is a phenomenon that occurs in coal dust pipes where the coal particles adhere to the pipe walls and accumulate over time, reducing the cross-sectional area of the pipe and causing flow disturbances. As a result, the velocity of the coal particles increases, causing erosion of the pipe wall and potentially leading to blockages and reduced system efficiency.

The root cause of roping is typically related to the properties of the coal itself, such as its size distribution, moisture content, and chemical composition. For example, coal with a high moisture content can stick together and form clumps, which can then coalesce into a rope-like structure under certain conditions. Additionally, changes in the velocity or direction of the gas flow within the pipe can also contribute to the development of roping.

Roping can have significant negative impacts on the performance of a power plant, such as reduced coal flow and combustion efficiency, increased pressure drop and power consumption, and even the risk of pipe blockages and equipment damage.

To mitigate the "roping" phenomenon in coal pipes, several measures can be implemented which are very much in line with the measures to mitigate pf. distribution. Both issues are interconnected in the context of coal handling and combustion systems in thermal power plants. Addressing one issue often involves considerations and strategies that can impact the other, making it important to approach them together for optimal performance.

For future reference, it is recommended to conduct coal dust sampling in accordance with ISO 9931 guidelines. Following these established standards ensures consistency and accuracy in the sampling process, allowing for reliable and comparable results.

Coal Dust Fineness

The fineness should, according to design, be more than 70% for a 200 mesh (75 microns) which not always achieved for all mills. The coal dust fineness deviations for both 1st and 2nd low load tests are shown in Figure 86.

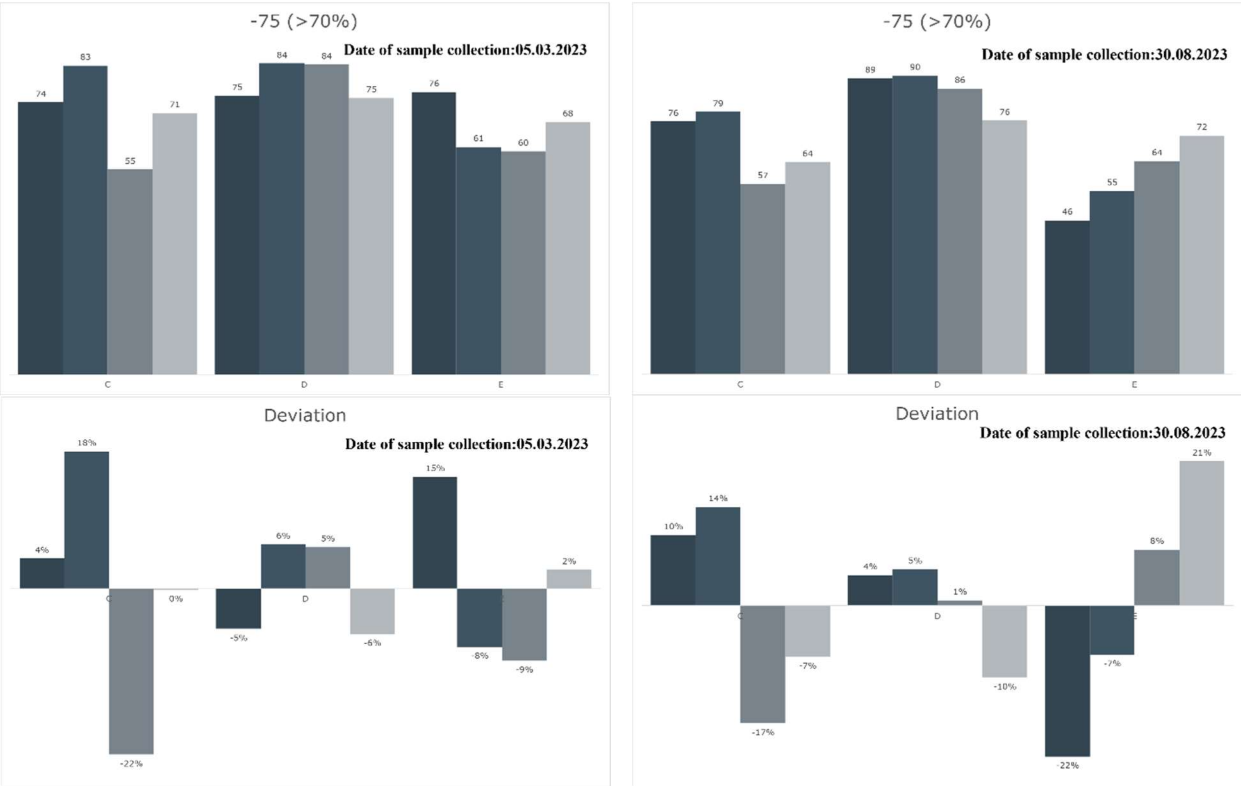


Figure 86. Mill coal dust fineness (-200 (>70%)) and deviations.

While the average fineness is in line with the requirements, the deviations between the individual pipes are too high.

In general, if the pf. is too coarse, it may not burn completely within the combustion chamber. Conversely, excessive fine pf. can suspend in the air (flue gas) for extended periods without burning efficiently. This condition can lead to a phenomenon known as "fly ash carryover," where fine particles are carried out of the boiler and into the flue gas, potentially causing fouling and corrosion in downstream equipment such as air heaters and electrostatic precipitators.

Burner Flame Detection

In general, to classify a flame as "acceptable", it is expected that the flame intensity level remains consistently above 40%, and the flame signal should exhibit stability without flickering.

The significant variation in intensity levels at same burner level is unacceptably high. Several potential factors may contribute to this issue. While the quality and distribution of pf. are one aspect, it's also essential to emphasize the quality of the scanners as they could be a contributing factor. Therefore, we recommend conducting a verification of flame scanner signals as part of the troubleshooting process.

- Verify flame scanner signals.

The verification process should commence with visual inspections and proceed to equipment maintenance and calibration. In some cases, it may become necessary to replace the existing scanners with newer and more modern ones to address any issues with flame signal variability effectively.

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The flame scanners seem to be providing trustworthy measurements, and the general intensity level is acceptable above 40%. However, there are occasional instances of flickering that have been noted.

The flame intensity plots indicate a weaker flame signal in the "DE" measurements which can be attributed to the relatively poor coal dust distribution from mill "D."

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Same observations apply.

Combustion

According to the design data, the UBC should be below 2%.

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During the first test, bottom ash UBC was measured as 3% and fly ash was 0.22%, which is not alarming levels.

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In the second test, there was a slight increase in UBC observed in the bottom ash in two samples, measuring 2.9% and 4.8%. The elevated reading can be attributed to the fact that the unit was in the process of ramping up during the test. It's worth noting that the UBC levels in the fly ash remained comfortably below the required level.

Oxygen

The O_2 percent was manually increased to ca. 9% before the APH. The relatively high secondary air (SA) flow is required to ensure that the SA dampers remain operational and maintain a good and controllable SA distribution.

However the boiler efficiency is compromised by a high O_2, i.e. the following findings should be noted:

- To ensure efficiency and accommodate SA dampers, the O_2 shall be adjusted appropriately.

The relatively high O_2 set point has a positive impact on the RH outlet temperature, as it promotes convective heat transfer over radiative heat transfer.

A high O_2 level is generally undesirable because it promotes the generation of thermal NOx. Therefore, minimizing excess O_2 levels is fundamental for reducing NOx emissions. By reducing the O_2 level and controlling NOx emissions, the combustion process can operate more efficiently and safely while reducing its environmental impact. Nonetheless, it is important to note that the primary source of NOx in coal combustion is the fuel generated NOx, which generally accounts for 60-80% of the total NOx emissions.

Fans

The fans (FD, PA, and ID) were operating without any significant issues during the 40% low load. The two ID fans were operating in parallel at approximately 50% load, while the FD operated at approximately 20% load, and the PA fans operated at 33-39% load.

When fans are operated in variable loads and are exposed to more challenging control requirements, variable frequency drive (VFD) control is generally considered to be a preferable option compared to blade pitch or damper control. Variable frequency drives allow for precise control of the fan speed by varying the frequency of the electrical supply to the motor. This allows the fan to operate at a range of speeds and maintain a consistent airflow, even when the load on the fan changes. In contrast, blade pitch control involves adjusting the angle of the fan blades to control the airflow, which can be less precise and more difficult to manage. Similarly, damper control involves adjusting the position of dampers in the fan system to control the airflow, which can result in inefficiencies and increased energy consumption. Overall, VFD control is generally considered to be a more efficient and effective way of controlling fans in variable load conditions and can help to reduce energy consumption and maintenance costs.

Boiler Drum Level

Boiler drum level control stability is critical for stable load control in a boiler system. The level of water in the boiler drum needs to be maintained within a narrow range to ensure efficient and safe operation of the boiler. Unstable boiler drum level control can also affect the overall stability of the system and make it difficult to maintain a stable load. Therefore, ensuring stable and reliable boiler drum level control is essential for achieving stable load control and safe and efficient operation of the boiler system.

The boiler drum level was manually controlled and didn't pose noteworthy challenges while operating in stable low load.

Indeed, it is apparent that the level control is being managed manually, as evidenced by the variation in level set points between the two tests. In an automated control system, the level would remain consistent during both tests, eliminating such discrepancies.

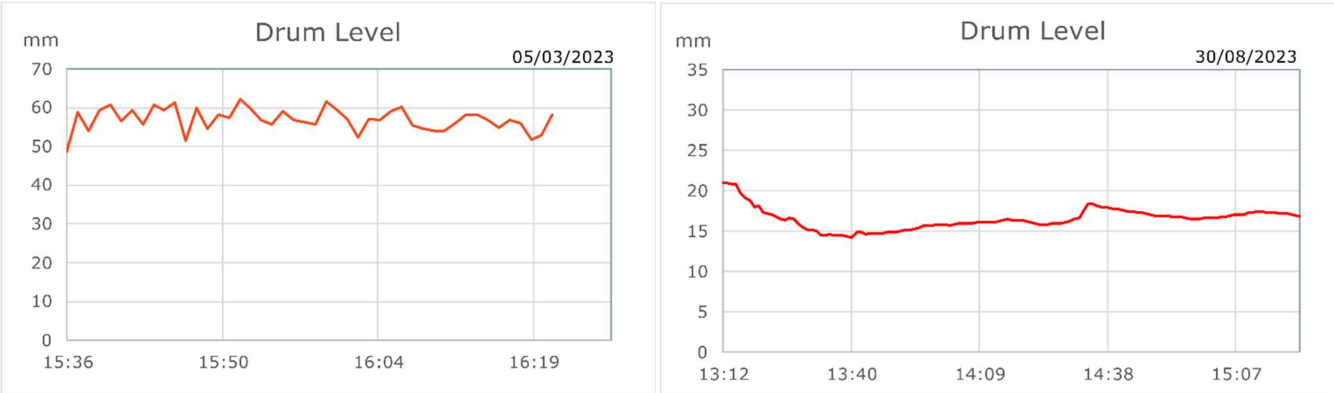

Figure 87. Drum Level.

1st low load test 5-3-2023

After the stable low load the load was increased in a high ramp rate, and the drum level control was challenged, and had fluctuation up to ca. 60 mm.

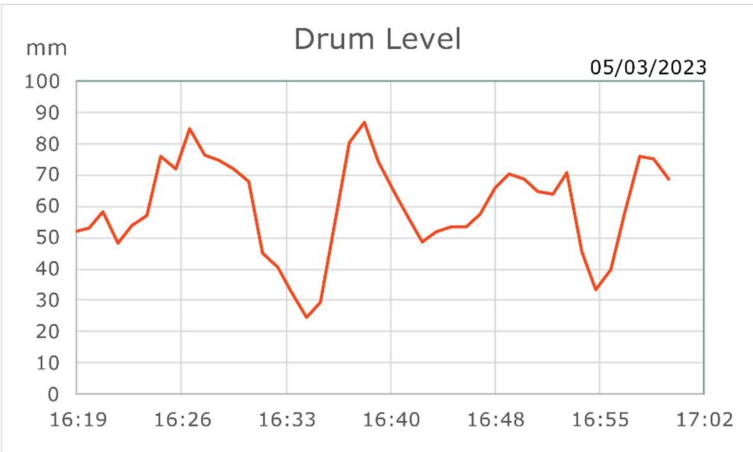

Figure 88. Drum Level during ramping up.

2nd low load test 30-8-2023

The level remained reasonably stable both during the low load and during ramping.

- Drum level control needs to be optimized for automatic control both during low load and high ramp rates.

Condensate Flow

To achieve a stable and controlled load, it is essential to have a consistent condensate flow. Fluctuations in the condensate flow leads to corresponding variations in the turbine bleeds for the preheaters. As a result, the generated power becomes unstable, causing an imbalance in load control.

- Condensate flow control needs to be optimized.

The measured condensate flow was quite unstable in both tests:

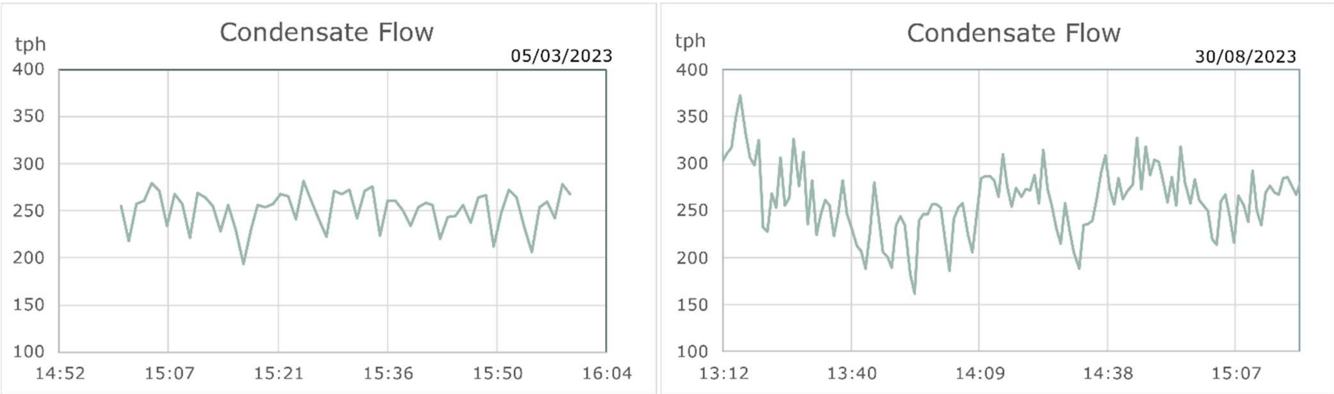

Figure 89. Condensate flow.

Acid Corrosion in Air Pre-Heaters

Short-term operation below the acid dew point does not pose a significant risk to APHs. However, sustained operation below the acid dew point should be avoided in order to prevent corrosion.

The exit flue gas temperatures from APHs were quite low, around 126 °C for APH "A" and 121 °C for APH "B" in the first test and a little lower in the second test; 124 and 117°C. Due to the absence of information regarding sulfur content in the coal analysis, conducting a thorough analysis of corrosion risk is not possible. However, assuming a standard sulfur content of 0.4%, an estimation of the dew-point temperature at around 100°C can be made. The measurement of the cold combustion air temperatures, PA and FD, falls within the range of 36-60°C. The Danish approach involves determining the APH plate temperature by averaging the gas and air temperatures, resulting in a range of 78°C to 93°C in this particular case. Therefore, the APH plate temperatures are significantly lower than the sulfur dew-point temperature, indicating a high potential for acidic corrosion in the APH's cold end.

Unfortunately, the Steam Air Preheaters (SCAPH) installed in the unit were not operational during the testing period. Had they been operational, the Steam Air Preheaters (SCAPH) could have raised the flue gas temperatures, resulting in APH plate temperatures above the sulfur dew-point temperature. This, in turn, would have helped mitigate the increased risk of corrosion.

- Perform necessary maintenance of the SCAPH's to mitigate the corrosion risk of the APH.

However, the SCAPHs are placed solely within the secondary combustion air system, primarily serving to mitigate APH corrosion rather than having the capability to increase the PA temperatures.

General Comments

The operation of both spray and burner tilt resulted in reaching the set point temperatures for both SH and RH due to the elevated O_2 level. To decrease the SH/RH temperature, the O_2 level can be reduced while keeping the SA damper control in place. However, it's important to note that a decrease in SH/RH temperature will only become problematic if the turbine exhaust wetness level exceeds the critical level, which can be obtained from the OEM, typically around 12-13%. If the SH/RH temperatures drops below acceptable levels, the temperatures can be raised by selecting a higher firing by choosing a mill combination which includes mill “F”.

It's important to consider that operating at a high firing rate is generally not recommended, as it can lead to lower furnace residence time, potentially causing increased unburned carbon (UBC) and slagging issues. However, during low-load operation, the residence time increases, and the furnace exit flue gas temperature decreases. Given these factors, using high firing may indeed be an acceptable solution in certain circumstances.

During the second test, there was a noticeable temperature difference between the outlet temperatures of the super-heater (SH) and re-heater (RH), with variations of up to 14°C between the two sides. This occurred while the spray control system was actively operating, underscoring the critical need for precise adjustments and optimization of the control parameters.

Reducing the O_2 level will also decrease the temperature of the flue gas, which will increase the potential for corrosion in the APHs. Conversely, maintaining a high O_2 level in lower loads promotes higher combustion temperatures and control, albeit on the expense of higher corrosion risk.

The absence of measurements for emissions such as CO and NOx can pose a challenge for optimizing combustion. These emissions are significant indicators of combustion efficiency and environmental impact. CO indicates incomplete combustion due to insufficient oxygen or unburned fuel. NOx indicates the formation of harmful nitrogen oxides that can contribute to air pollution and respiratory issues through high-temperature combustion reactions. Measuring these emissions can help in customizing combustion optimization to improve efficiency and lessen environmental impact. For example, reducing excess air can help lower NOx emissions while improving burner design. Insufficient measurement of these emissions makes it difficult to ascertain the effectiveness of the combustion process. This could result in reduced efficiency, increased emissions, and possibly even hazardous operating conditions. As such, it is essential to incorporate emission measurements as a part of any extensive combustion optimization programme. This step can help to guarantee that the combustion process is functioning efficiently, safely, and adhering to relevant regulations and standards.

Furthermore, several of the controls were handled manually by the control room operators which is not an ideal situation as it requires very skilled personnel.

Additionally, reviewing the following control loops is essential to enable the unit to operate in automatic mode during low loads and ramping. The following controls should be considered for reviewing:

a. Master unit control – fuel/load coordination.

b. SH and RH spray temperature control.

c. Boiler drum level control.

d. Oxygen control and fuel/air coordination.

e. Flue gas temperature control using SCAPH.

f. Mill loading

g. Mill stop and start.

h. Mill outlet temperature.

i. Ramping control. Automated start-up and shut-down of mills.

Finally, during both tests, it was observed that the pulverized fuel (pf.) distribution was not meeting the required standards. Unfortunately, the unit lacks any mechanism to control this challenge, which is considered a fundamental factor for achieving stable operation at lower loads.

8.2.2.4. Ramp Rate Test - 2nd day of 1st low load test

On the second day of testing, the ramp rate tests were conducted with the overall objective of demonstrating the unit's capability to meet the new standards.

There is a general policy in place for the unit that restricts the maximum coal consumption to 140 t/h, thereby setting an upper limit on power production.

The unit load was successfully reduced from 190 MW to 84 MW (40%) over a series of three individual steps. The low load was maintained for app. 30 minutes thereafter the load was ramped up in two steps. The low load up-ramp was interrupted and hence not recorded as a ramp test.

Raw coal and coal dust samples were collected during the testing process. The boiler heating surfaces were soot-blown before the test.

Downward High-Load Ramp Rate

The ramp rate between 100% and 70% were conducted with a mill setting of "ABCDE". At max coal consumption 140 t/h, the unit was able to generate ca. 190 MW. The ramp rate was achieved by taking mill "A" out of operation at. 10:05.

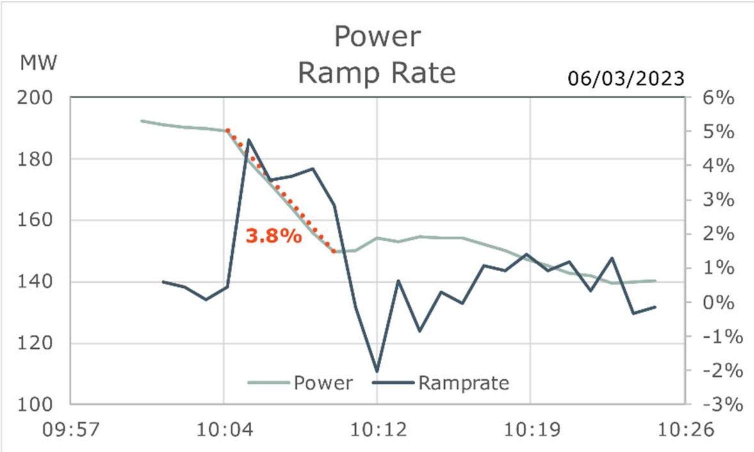

Figure 90. Obtained downward ramp rates in high load.

The max obtained ramp rate was ca. 4.7%, in average in the ramp rate was ca. 1.2%/min down to 70% (147 MW). During the "active" load reduction the, down to 150 MW, the ramp rate was app. 3.8%.

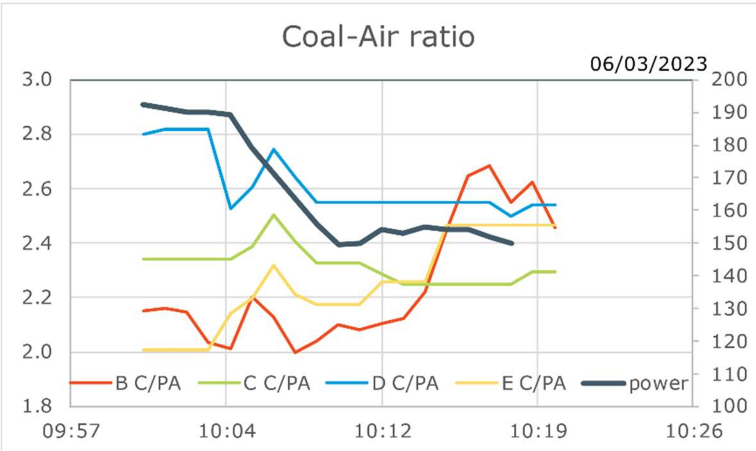

Figure 91. Coal-air ratio during high-range ramping.

The coal-air ratio makes an undesired pulse during ramping down, and the curve for mill "B" exhibits an unexplainable increase. A stable air/fuel ratio ensures consistent and stable combustion within the boiler. During ramping, maintaining a stable air/fuel ratio helps to prevent fluctuations in combustion efficiency and minimize the risk of combustion instability, such as flame instability or flameout.

- The PA flow control needs to be optimized for ramping.

Downward Mid-Load Ramp Rate

The next ramp rate, from nominally 147 to 115.5 MW, was obtained by manually taking out mill "B" at 10:50. The average ramp rate until 10:55 was ca. 1.7%, with a max. of 2.5%.

The unexpected increase in Mill "E" load, resulting in a minor load increase and delay, can be attributed to the manual load control of the unit. This incident highlights the absence of automated load/fuel/air control, which would have helped prevent such issues.

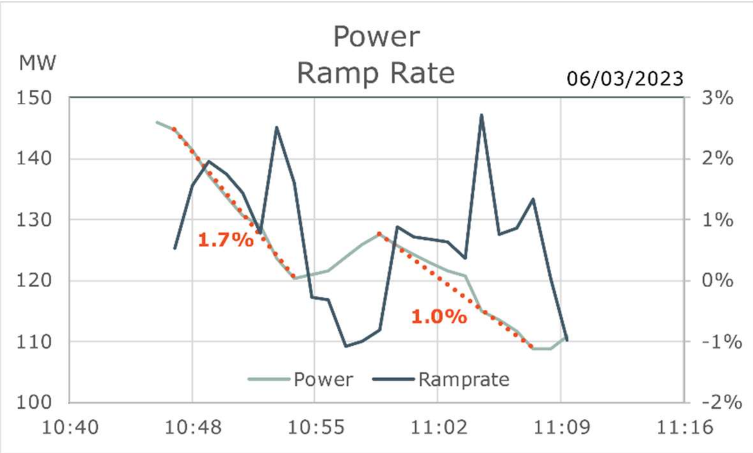

Figure 92. Obtained downward ramp rates in mid load.

In the total load reduction to 115 MW, the average ramp rate was ca. 0.8%.

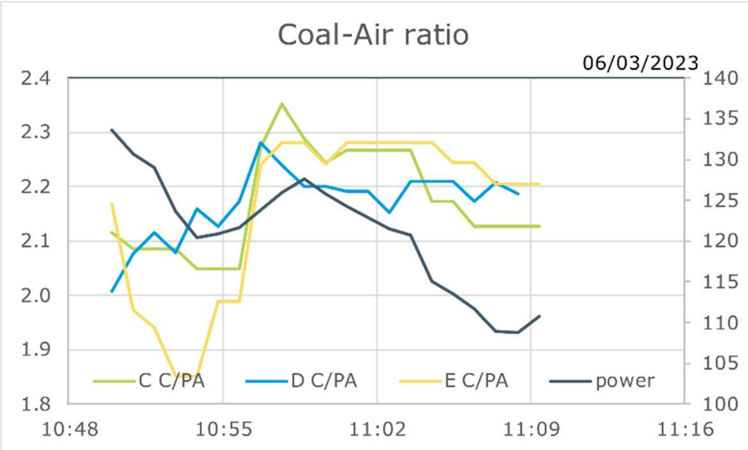

Figure 93. Coal-air ratio during mid-range ramping.

As seen during high-range ramping, the coal-air ratio was very unstable.

Downward Low-Load Ramp Rate

The ramp rate in low load, was obtained by reducing the mill loads manually. The average ramp rate was ca. 1% which is in accordance with the new standard.

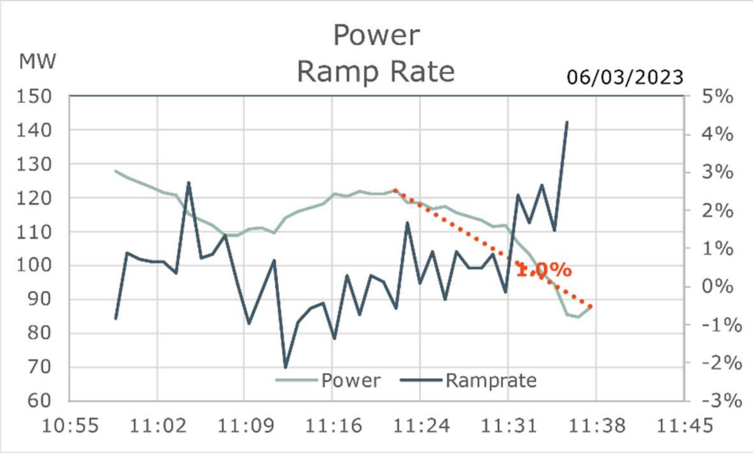

Figure 94. Obtained downward ramp rates in low load.

- The load stability must be increased by optimizing the control of coal feeder, PA and SA.

Upward Mid-Load Ramp Rate

The first upward ramping was started at 15:30 by increasing the load of mill "C" and "E", at 15:40 mill "B" was brought into operation.

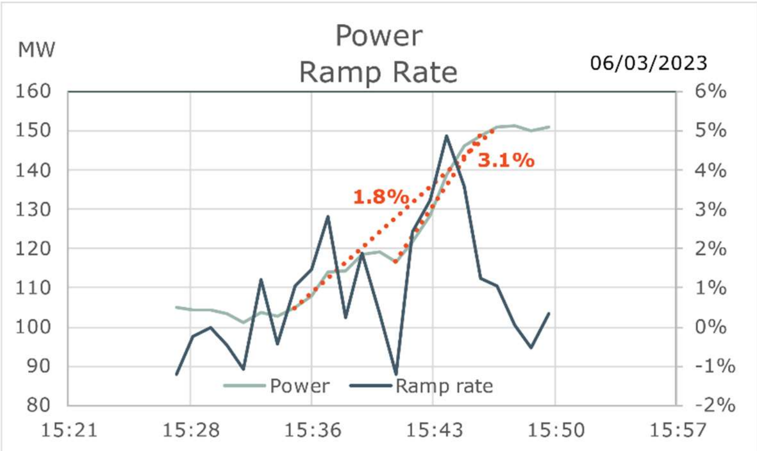

Figure 95. Obtained upward ramp rates in mid load.

The mid load ramp rate was in average 3.1%, while the ramp rate including the lower load was ca. 1.8% These ramp rates indicate the speed at which the load was changing during operation.

However, it is observed that the load control during these ramp rates was quite unstable, suggesting the need for mitigation measures to address this issue.

Upward High-Load Ramp Rate

The high load ramping started at 15:57 after mill "A" was put into operation at 15:54. The ramp rate from 148 to 191 MW was in average 2.6%

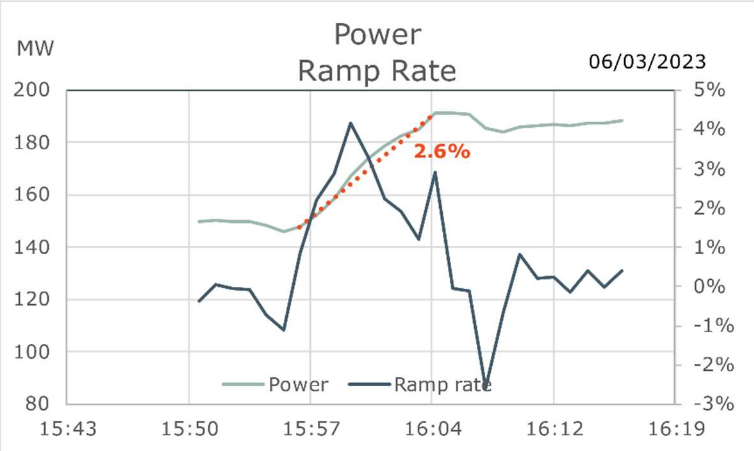

Figure 96. Obtained upward ramp rates in high load.

General Observations During Ramping

Both burner tilt and SH/RH spray injection was in operation during all operation, anyway,

- The SH and RH outlet temperatures were fluctuating and not in control.

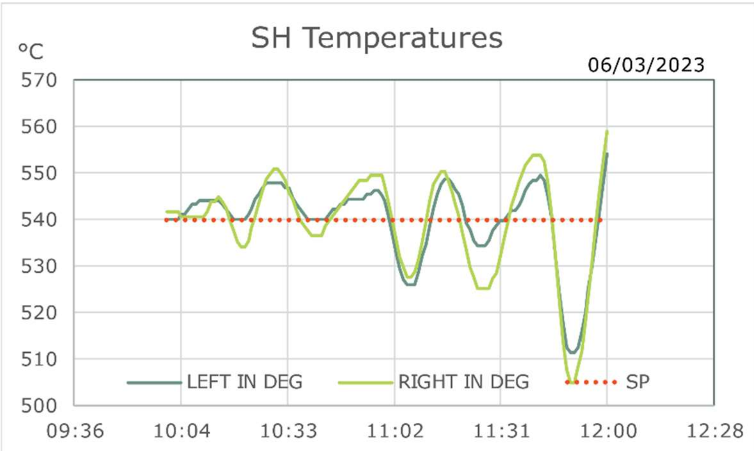

Figure 97. SH temperature variation during ramping.

Dead time from loading mill to power app. 3-4 minutes.

- The fans (ID/FD/PA) remained within normal operation ranges during ramping and were not compromised.
  For both ID and FD fans demand and feedback were corresponding. (The data didn't include data for PA feedback)

- To optimize ramping control, it will be beneficial to coordinate the ramping rates of mills and feeders. Specifically, all mills and feeders should be exposed to the same ramp rates.

- During ramping, it is optimal to have the PA (primary air) flow control in automatic mode rather than manual, as was the case during the said tests.

- The stability of the drum level was compromised during the ramping process. To resolve this issue, it is recommended to optimize the level control system. Additionally, when operating at lower loads, there is a possibility that the boiler feed-water pump (BFP) may enter a regime where it becomes necessary to open the recirculation valve. However, it should be noted that this action can further destabilize the controls.

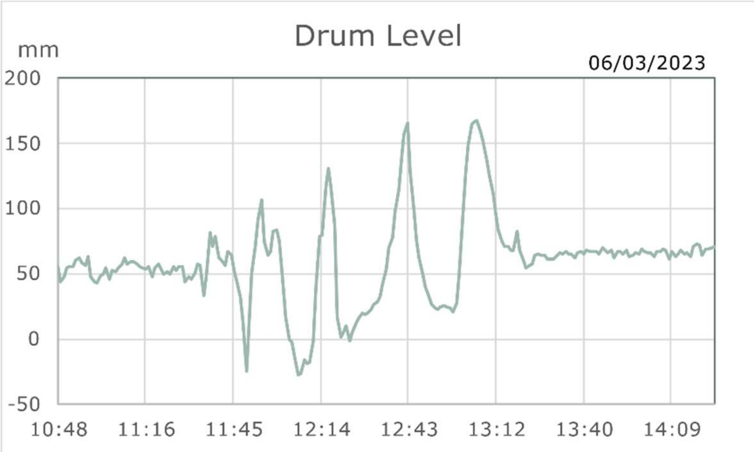

Figure 98. Drum level variation during ramping.

- Furnace pressure is not controlled sufficiently. The controls of SA pressure and furnace pressure must be decoupled and optimized to remove oscillations.

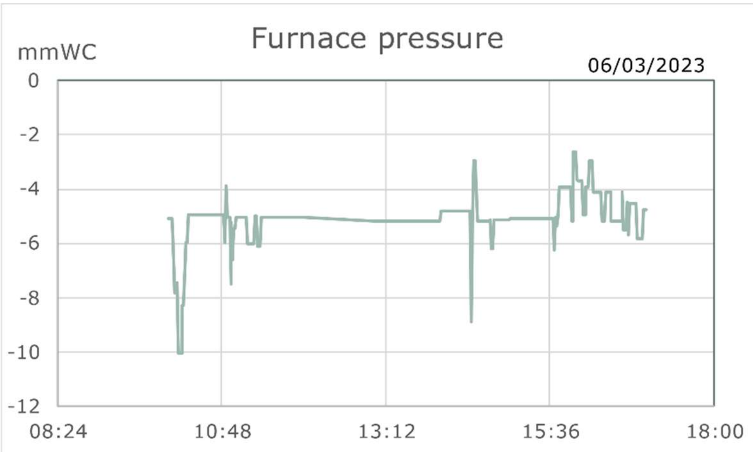

Figure 99. Furnace pressure variation during ramping.

- Metal temperatures are influenced by the corresponding steam temperatures. If the temperatures in the super-heater (SH) and re-heater (RH) are not properly controlled, it can result in unacceptable consumption of the component's remaining lifetime.

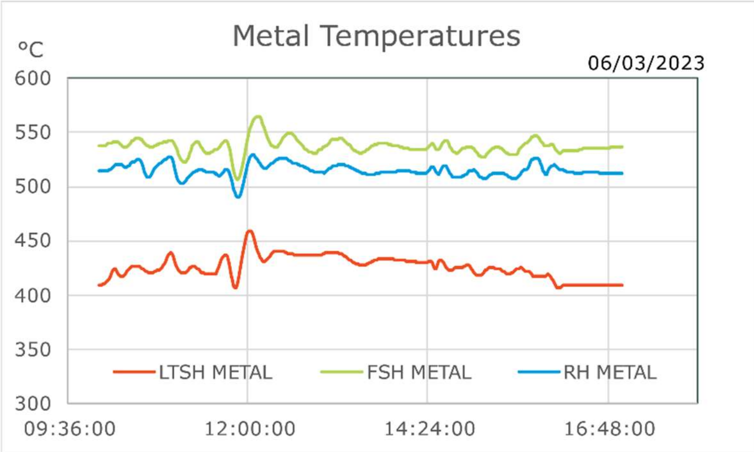

Figure 100. SH/RH metal temperature during ramping.

The manual load control system relies on control room operators to adjust and regulate the load, fuel, and air parameters. However, operators may not always be able to respond quickly or accurately enough to sudden changes in the system. This can lead to inconsistencies, delays, or even errors in load adjustments, as observed in mentioned incidents. In contrast, an automated control system utilizes advanced algorithms and sensors to continuously monitor and adjust the relevant parameters in real-time. Such a system can respond swiftly and precisely to variations in load demand, optimizing the combustion process and maintaining stable operation. Implementing automated control can greatly enhance the overall performance and reliability of the unit, minimizing load fluctuations, reducing delays, and improving operational efficiency.

8.2.2.5. Ramp Rate Test – 2nd day of 2nd low load test

On the second day of testing, we encountered a problem with the fuel quality, resulting in inadequate combustion and oil guns were put into operation. The flames exhibited too low intensity and had a flickering behavior, raising concerns about the potential of a system trip during the ramp rate test. Consequently, a unanimous decision was made to cancel the scheduled ramp rate tests. To avoid tripping the load was increased and additional mills were taken into operation.

In retrospect, reviewing the coal quality, the coals were not significantly worse than expected. The water content increased ca. 1% from 10.6 to 11.7% and the ash content reduced from 53.5 to 50.5%. Additionally, the GCV exhibited a favorable increase, raising from 2773 to 3027 kcal/kg. These findings suggest that the coal quality, although not ideal, did not pose a major hindrance to the conducting the proposed testing process. Alternatively, the coal quality was unstable with varying content of water and ash, which also can explain the flame flickering.

One explanation can be a major variation in the Hardgrove Grindability Index (HGI) for the lower range. Unfortunately the HGI was not analyzed. According to documentation the coal quality appeared to exceed the “worst” coal specification. This was indicated by a minimum HGI of 45, a maximum ash content of 40%, and a minimum Gross Calorific Value (GCV) of 3500 kcal/kg.

Consequently, a new manageable test was proposed and agreed upon.

The air-coal ratio's impact on the flame intensity was tested for mill "A".

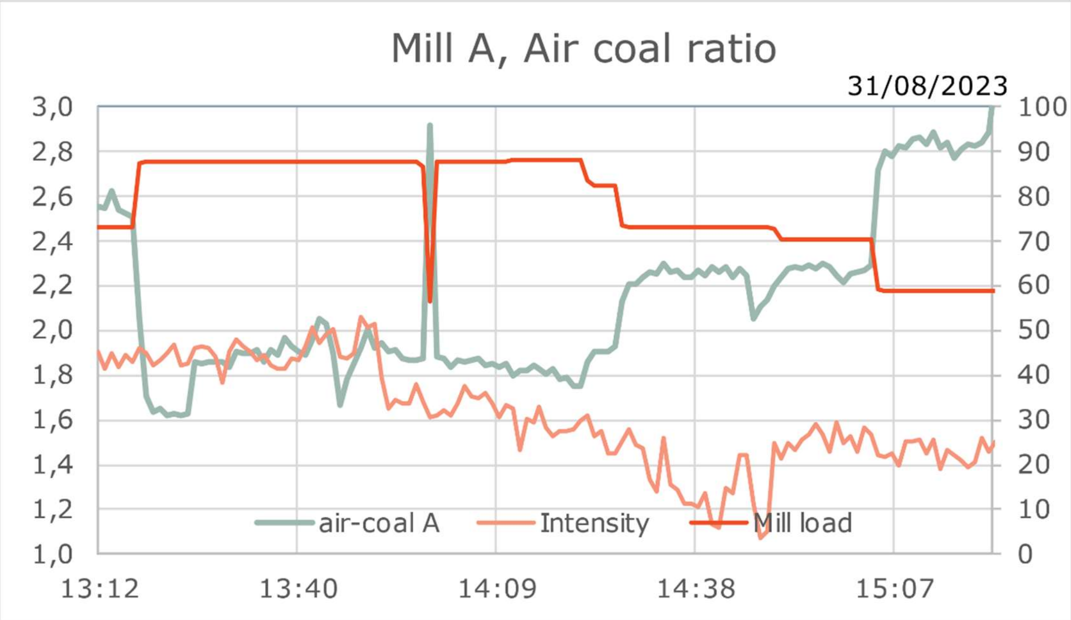

Figure 101. Air-coal ratio and flame intensity.

As shown in Figure 101, it's clear that as the air-coal ratio increases from approximately 1.8 to 2.25, while the flame intensity decreases from about 45% to 25%. However, it's important to note that during this change, the mill load also decreases from around 88% to 59%. This reduction in mill load has an impact on the flame intensity and makes it challenging to draw a definitive conclusion.

8.2.2.6. *Efficiency*

The EN standard 12952-15 has been used to calculate the boiler's efficiency and/or heat rate by applying its formulas based on the lower heating value. The standard also allows for the calculation of the fuel input, which can then be compared to the measured fuel flow.

Table 8-7 Calculated efficiencies and heatrates

Raichur	Unit	5/3 2023	30/8 2023
EN 12952-15 Fuel efficiency (LHV)	%	90,8	86,4
- Converted to GHV	%	84,4	78,7
Water steam heat (Q_N)	MW	223,0	224,0
Gross Unit Heatrate (LHV)	kcal/kWh	2478	2789
Gross Unit Heatrate (HHV)	kcal/kWh	2640	3016
Gross Unit efficiency (LHV)	%	34,7%	30,8%
Gross Unit efficiency (HHV)	%	32,6%	28,5%
Turbine Heatrate	kcal/kWh	2251	2409
Fired fuel	MW	245,5	259,3
Fired fuel mass flow	t/h	68,2	87,2
Measured fuel mass flow	t/h	70,6	89,7
Fuel mass flow difference	t/h (%)	2.4 (3.6)	2.5 (2.9)

The difference between measured and calculated fuel flow is within an acceptable range.

The Heat and Mass Balance Diagram (Figure 102, Figure 103 and

Figure 104), derived from the measurements and Thermoflex ®, reveals several noteworthy observations:

- The exhaust shows a relatively low moisture content (2%), suggesting a very low risk of erosion wear in the turbine outlet.
  Additionally, this finding implies that the temperature demand for the reheater (RH) can be eased or relaxed, as there is less concern about moisture-related issues in the system.

- The condenser demonstrates a relatively high terminal temperature difference (TTD) value of 15.4K, which, when compared to the initial Heat and Mass Balance Diagram for an 84 MW system with a cooling water temperature of 33°C, reveals a design TTD of 1.4K. If the condenser were operating according to its intended design, the anticipated exhaust temperature for the current cooling water temperature of 29°C would be around 36°C (Figure 102) However, the measured temperature is approximately 49°C, indicating an over-temperature of 13°C. This substantial deviation strongly suggests the presence of air entrainment within the condenser system.

- The low pressure heaters are not operational, likely due to the air entrainment and the increased pressure, which hinders their proper functioning.

By eliminating air entrainment and ensuring the proper functioning of the condenser and LP preheaters, the result would be a reduction in exhaust pressure to approximately 59 mbar (44 mmHg). This decrease in pressure would result in the turbine generating approximately 5 MW of extra power and increase the exhaust moisture to ca. 5%. The additional power output would lead to an improvement in unit efficiency of around 2 percentage points.

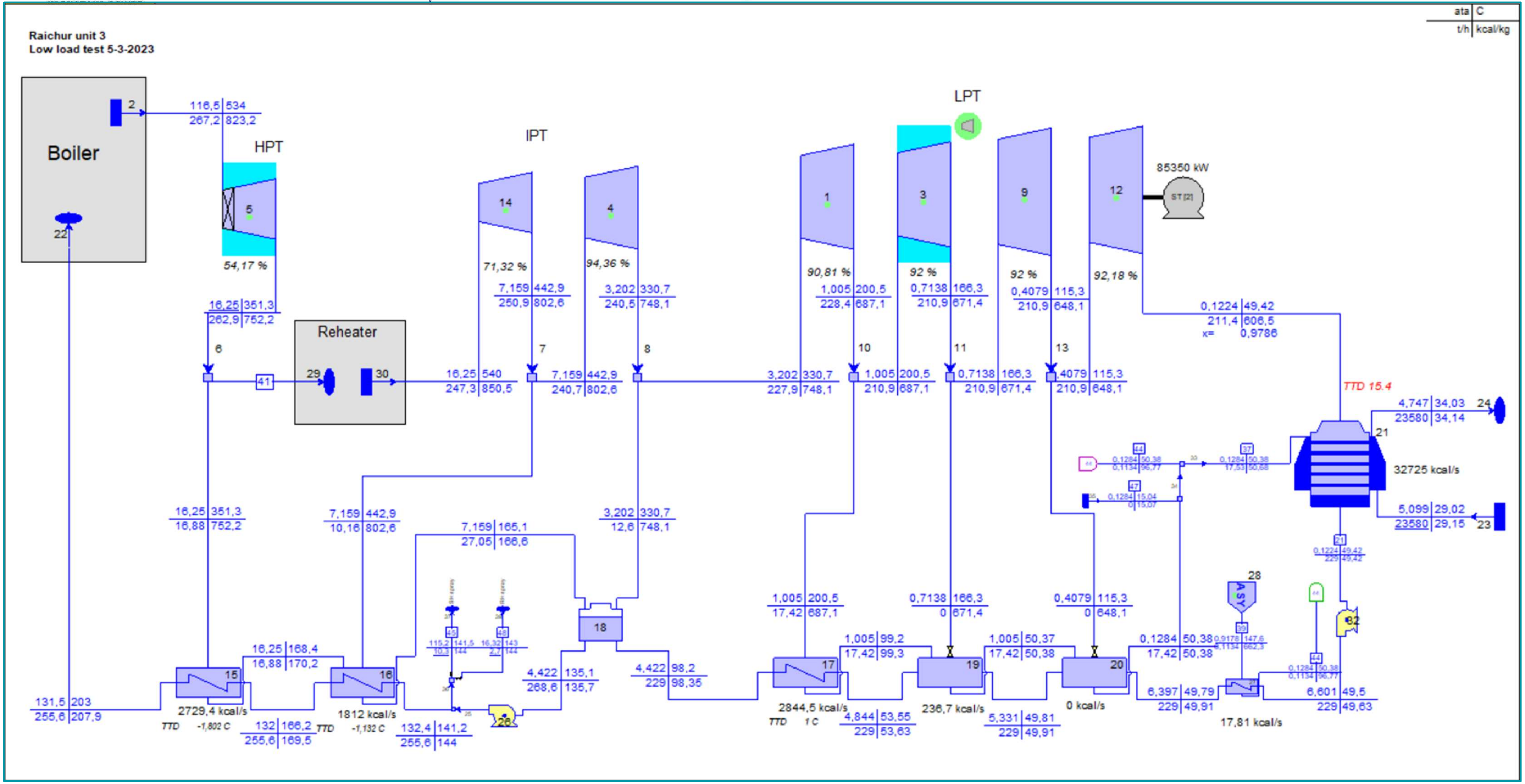

Figure 102. HMBD low load test 5/3-2023.

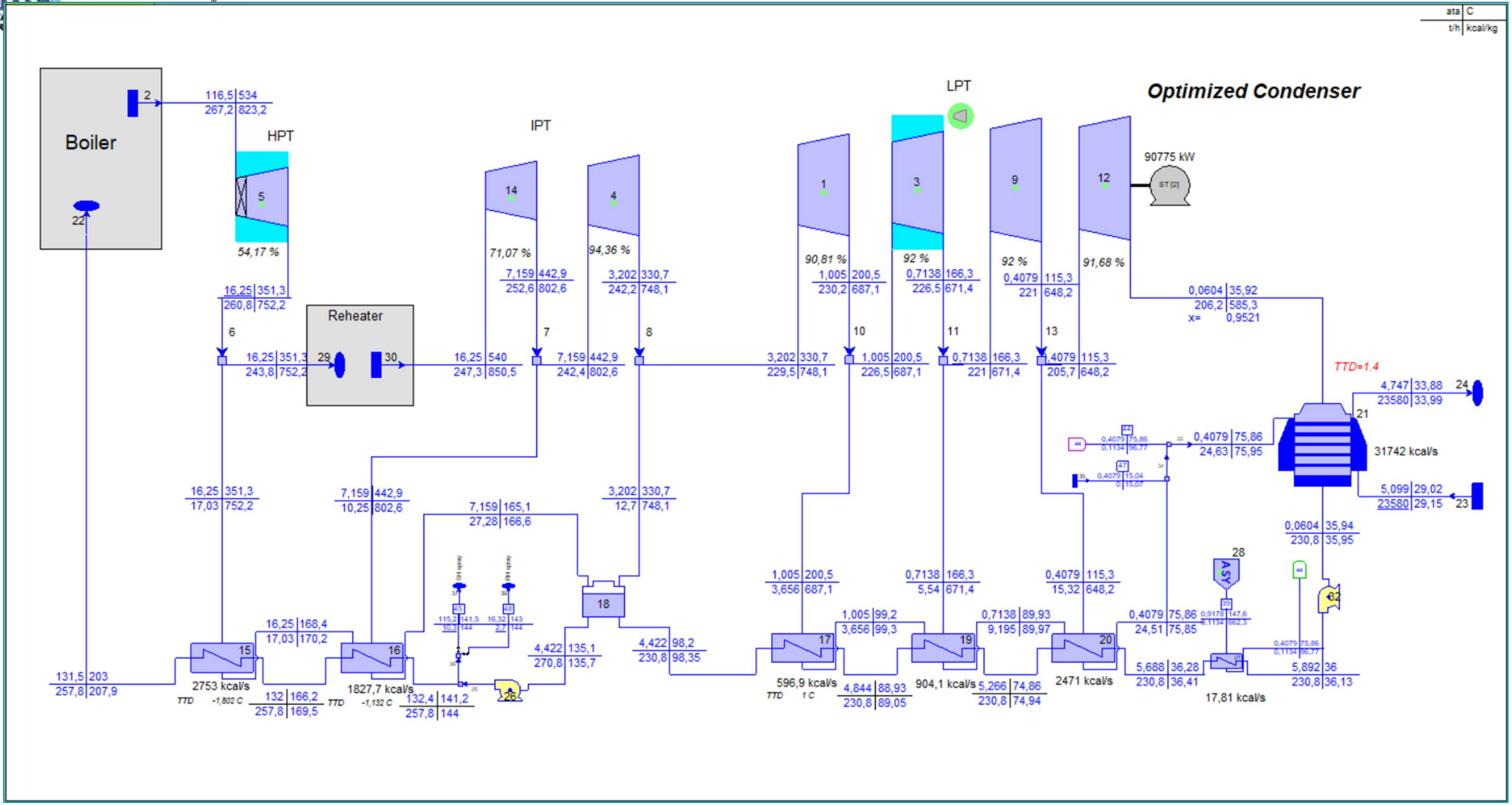

Figure 103. Optimized HMBD low load test 5/3-2023.

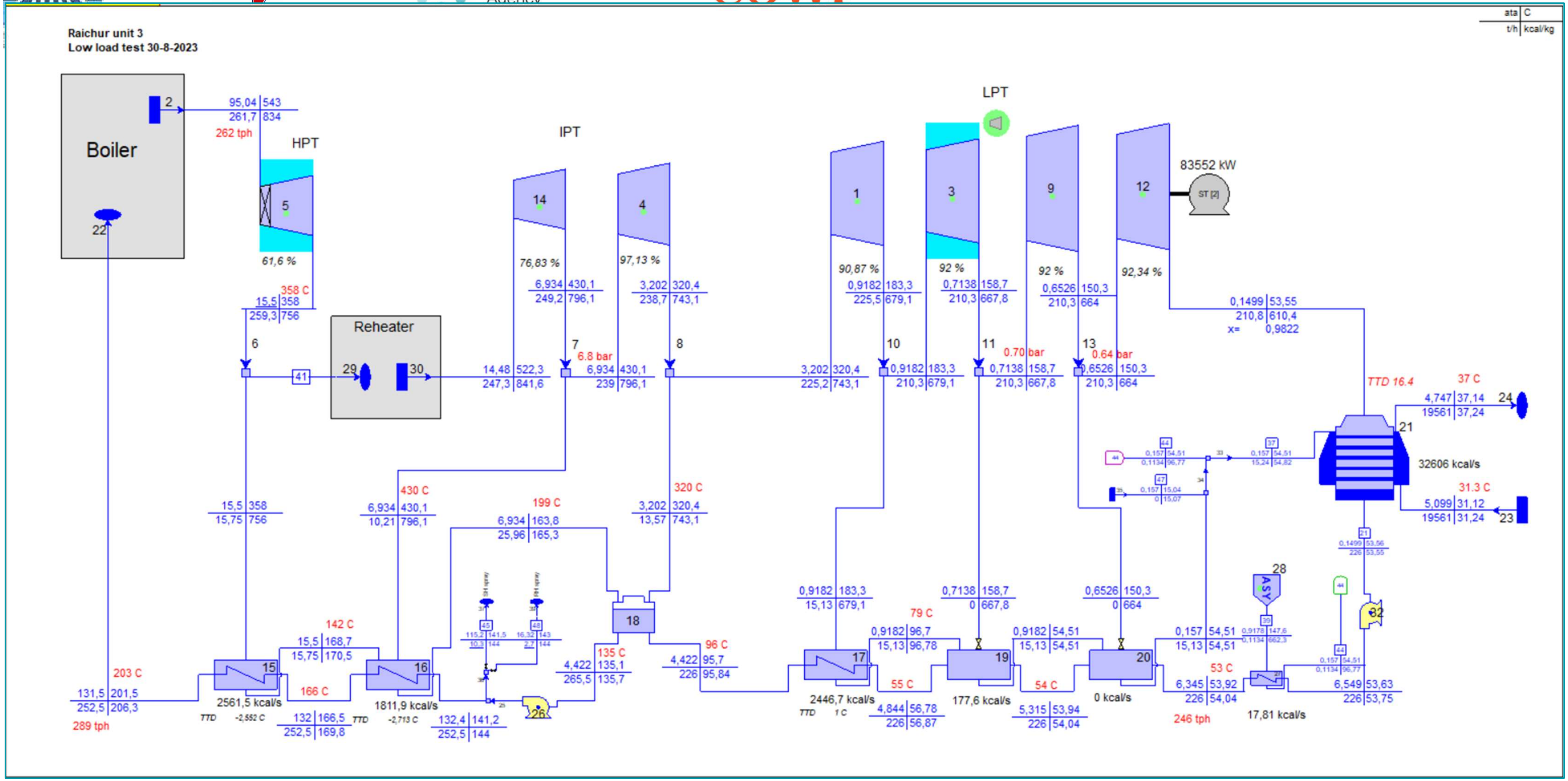

Figure 104. HMBD low load test 30/8-2023.

8.2.2.7. Controls

During low loads and ramping tests, the unit was predominantly operated in manual control mode. Although this was necessary for testing purposes, it is highly recommended to optimize the controls to enable unit load control through few set point in the unit control system.

The following outlines several significant characteristics of unit control systems utilized in Danish power plants:

- Load Demand Signal: The Unit Master Controller, employs a load demand signal that is split into separate signals for boiler load demand and turbine load demand. This division considers the maximum dynamic changes that the boiler and turbine can handle. Jump and gradient limiters are adjusted to the individual dynamics of each component. The Unit Master Controller is used to ensure that the boiler and turbine is always in balance, and will ensure that the boiler and the turbine, will only create a change that is within the limits of each other. Also, the Unit Master Controller will ensure that any process limiting factors are utilized in calculating the required set-point. An example could be limiting factors of Mill in operation, feed water pumps, combustion fans, to high condensate pressure etc.

- Feed Forward Control: The unit load demand signal serves as a feed forward signal, guiding and controlling the primary controllers responsible for fuel, feed water, combustion air, steam temperature and turbine operations. The set-point signals are changed gradually to achieve smoother load changes and reduces the need for the slower dynamic feedback controllers to undergo extensive load ramps.

- Damping Effect: The use of feed forward control derived from the unit load demand signal has a strong damping effect on oscillations between the primary controllers. By directly guiding the controllers to the required output, disturbances caused by load changes are minimized. This is especially important in maintaining the proper balance between fuel combustion air and feed water during load variations.

- Unit Master Control: The unit master control is not a standard feedback controller but rather a function used to calculate the desired set-points depending on the different load requirements, for the underlying feedback controllers. It also generates pressure set points based on inputs such as electrical load set points, gradients, and potentially district heating set points. It does receive feedback during operation, which is used to calculate the required feed forward signals.

- Gradient Limitation: The Unit Master Control incorporates gradient limitation mechanisms to ensure smooth load transitions. These mechanisms, such as set point controllers

(SPC), receive gradient up and gradient down inputs. Operators can adjust the desired gradient, but it may be limited by stress calculators associated with the boiler and turbine. These stress calculators monitor and prevent excessive differential temperatures in the thick metal components, which can lead to thermal stress and premature component degradation.

The primary objective of unit control is to ensure the coordinated operation of the two main components within the system, namely the boiler and the turbine, in order to meet the required load of electricity and heat without causing any component to overload. The Unit Master Controller can be considered as a superior load control mechanism that orchestrates the actions of the boiler and turbine to work in tandem towards a shared objective. The unit control system must simultaneously regulate two key outputs: the net electrical production of the system and the steam flow production from the boiler. By controlling these variables, the unit control system maintains stability and optimal performance throughout the power generation process.

The tasks of the unit master controller are illustrated in the following figure:

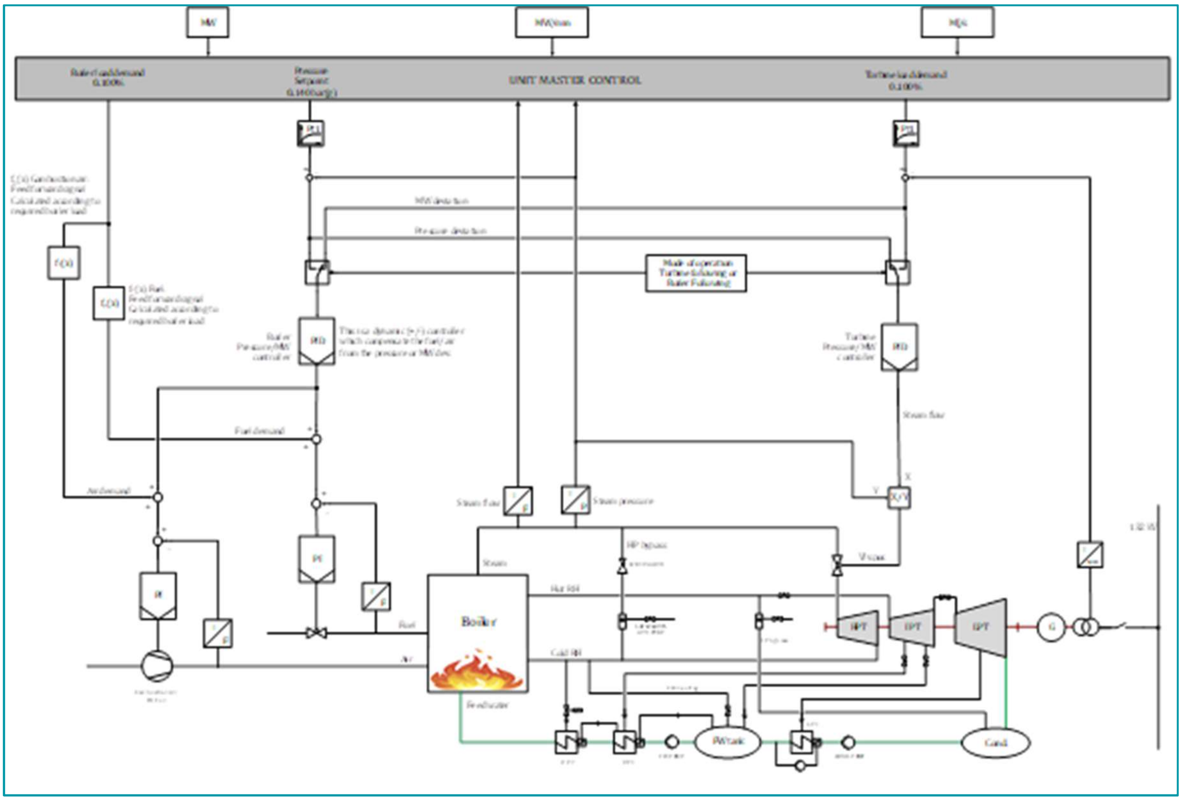

Figure 105. Unit master control design.

The Unit Master Control plays a critical role in rapidly reducing the overall plant load to a safe level if any primary aggregates fail. This prevents tripping of the entire block. Load limiting intervention mechanisms reduce the unit load demand signal with a predetermined gradient. Additional measures, such as switching the turbine to pressure control and the fuel control to manual operation and stopping the load change until a stable process is achieved, may be employed to stabilize the situation, avoid system disruptions, and protect the equipment from overload.

The Unit Master Controller used in Danish power plants prioritize efficient load management, smooth transitions, and protection of critical components through a combination of feed forward signals, gradient limitation, and load limiting interventions.

The unit load demand signal is divided into a boiler load demand signal and a turbine load demand signal, considering the maximum dynamic changes that the boiler and turbine can achieve at any given load. This division is accomplished through set-point controllers and gradient limiters that are adjusted to accommodate the unique characteristics of each component.

The purpose of the unit load demand signal is to generate feed forward signals that control and guide the primary controllers responsible for fuel, combustion air, feed-water, air, and turbine operations. This approach is particularly important during requirements for fast load changes, as it allows the slower feedback controllers to avoid large load ramps.

By using feed forward signals derived from the unit load demand signal, the primary controllers effectively dampen any oscillations that may occur between them. The feed forward signals provide direct instructions on how to adjust, preventing strong disturbances caused by load changes. For example, maintaining the appropriate balance between fuel and feed water during a load change would be challenging without the use of feed forward signals.

It is important to note that the unit master controller is not a controller. It is working as a manager or conductor, by directing the main components by their ability to perform, according to the required demand and the actual operational ability at a given the load. It does so by always calculating the required set-points and use feed forward signals for the underlying dynamic feedback controllers.

Additionally, the unit master control is responsible for establishing pressure set points. It receives input in the form of set points for electrical load, corresponding gradient, and possibly a set point for district heating.

- Load Control: Unit control is responsible for managing the load demand placed on the drum boiler. The control system adjusts the fuel input and combustion rate to match the required load, ensuring that the boiler generates the necessary amount of steam to meet the electrical demand.

- Steam Pressure Control: The control system adjusts the fuel and air supply to maintain the desired steam pressure.

- Water Level Control: The unit control system monitors the water level and regulates the feed-water flow to maintain a stable level.

- Combustion Control: It monitors parameters such as fuel flow, air supply, and excess oxygen levels to maintain efficient and stable combustion.

- Safety Monitoring: Unit control includes comprehensive safety monitoring. The control system continuously monitors critical parameters, such as steam pressure, water level, and flame stability, to ensure safe operation. It can trigger alarms, shutdowns, or corrective actions in case of any abnormal conditions or potential hazards.

Overall, the main characteristic of unit control for a drum boiler is to control the steam pressure, control load demand, maintain water level, optimize combustion conditions, ensure safety, and optimize efficiency. These characteristics ensure smooth, reliable, and efficient operation of the drum boiler within a thermal power plant.

Ramping control

To ensure a smooth transition, the block net load should change in accordance with specified gradients. This smooth transition is achieved using a set point slider (SWF) block, which receives inputs for both a gradient up and a gradient down.

Typically, the operator has the ability to adjust the desired gradient, such as 5 MW/minute, that the block should follow. However, the gradient may be restricted by stress calculators associated with the boiler and turbine.

The role of the stress calculators is to monitor the differential temperatures in the thick metal components, preventing them from reaching excessively high levels. High temperatures create thermal stress, which accelerates the degradation of these components, reducing their remaining lifetime.

If the differential temperatures exceed the acceptable threshold, the gradients will be reduced, potentially even down to zero, causing the block to slow down its rate of load change.

The challenge lies in accurately predicting when these issues may arise in the future. Actual measurements of thermal tensions always lag behind real-world developments, as these tensions take some time to develop.

Hence, there is a risk of surpassing the maximum limits and depleting the lifetime of components too quickly if a model-based stress calculator that can forecast future conditions is not employed.

Load limiting interventions

One critical responsibility of the unit master control is to rapidly reduce the overall plant load to the maximum achievable level in the event of a primary aggregate failure. For instance, if a plant has two 60% feed water pumps and one of them fails while operating at full load, the load of the entire plant must be swiftly reduced to 60% to prevent a trip caused by high steam temperatures.

This reduction is achieved through the load limiting intervention mechanism, which rapidly decreases the unit load demand signal to 60% using a predetermined gradient. The primary purpose of this mechanism is to prevent a complete shutdown of the entire block due to the failure of a single main aggregate.

In addition to reducing the unit load demand signal, the turbine is often switched to pre-pressure control to maintain stable boiler pressure through fast turbine valve adjustments. This helps prevent undesirable boiling in the economizer. Furthermore, switching the fuel control to manual operation avoids unnecessary disruptions in the fuel supply.

When the turbine is switched to pre-pressure control and the fuel control is set to manual, the coordinated operation between the turbine and the boiler is temporarily suspended. Essentially, they are no longer operating in sync with the unit load demand signal to achieve a common objective.

Once the situation has been stabilized and brought back under control, the turbine and the boiler can be switched back to automatic mode, and coordinated operation is resumed.

Implementation

Thorough testing is critical for any new control loops before they are implemented online. Additionally, it is essential for the control room personnel to be educated in the control philosophy and understand how to effectively utilize these new controls. Building confidence among control room personnel in the use of new controls is imperative to ensure the plant can be operated with a sense of assurance and proficiency.

It is proposes to consider implementation of the following control measures:

- Master unit control – fuel/load coordination.
- SH and RH spray and burner tilt temperature control.
- Boiler drum level control.
- Condensate flow control.
- Oxygen control and fuel/air coordination.
- PA flow and temperature control
- Flue gas temperature control using SCAPH.
- Furnace pressure control.

- Ramping control.
- Automated start-up and shut-down of mills.

These controls, when properly implemented, will contribute to the efficient and optimized operation of the system.

8.2.2.8. Lifetime consumption

In power plant's, the term "lifetime consumption" refers to the gradual wearing out of the materials used in the plant due to prolonged exposure to high temperatures and pressure. Over time, the components such as the pipes and headers will experience damage caused by the chemical reactions and physical stresses that occur during operation. This can eventually lead to a decline in the plant's performance and efficiency, and ultimately may require the replacement of certain parts. Therefore, it is important to carefully monitor the lifetime consumption of the plant and perform regular maintenance to ensure that it continues to operate safely and efficiently for its intended lifespan.

While lifetime consumption monitoring can offer valuable insights into the remaining lifetime and stress status of critical components, it is not considered essential nor necessary for implementing flexible operation.

An online lifetime calculator for a power plant uses mathematical models and algorithms to predict the remaining useful life of the boiler components based on various input data. The input data may include information such as the operational parameters of the boiler, the materials used in its construction, and the environmental conditions to which it is exposed.

The calculator uses this input data to estimate the rate of material degradation or wear and tear on the components over time, based on the specific mechanisms of degradation that are known to occur. The calculations may also take into account the effects of temperature, pressure, and other factors on the expected lifespan of the components.

By continually updating the input data and running the calculations, an online lifetime calculator can provide real-time predictions of the remaining useful life of the components, allowing for proactive maintenance and replacement planning. This can help to optimize the performance and efficiency of the plant, while minimizing downtime and costs associated with unexpected component failures.

There are several calculation models that can be applied to estimate the remaining lifetime of power plant boilers. Here are some common examples:

a) Creep-Fatigue Model: This model combines the effects of high-temperature creep and fatigue damage on the boiler components. It takes into account the loading conditions, materials properties, and operating parameters to estimate the remaining life of the boiler.

b) Larson-Miller Parameter Model: This model uses the Larson-Miller parameter to predict the lifetime of materials at high temperatures. The model is based on the assumption that the lifetime of a material is related to the amount of strain it experiences at high temperatures.
c) Coffin-Manson Model: This model is used to estimate the fatigue life of materials subjected to cyclic loading. It relates the number of cycles to failure to the maximum stress range and the material's fatigue properties.
d) Thermal-Mechanical Fatigue Model: This model takes into account the effects of thermal and mechanical loading on the boiler components. It accounts for the temperature gradients and stresses that are generated during startup, shutdown, and load changes.
e) Probabilistic Model: This model uses statistical methods to estimate the probability of failure of the boiler components. It takes into account the variability in materials properties, loading conditions, and operating parameters to calculate the remaining life of the boiler.

The choice of calculation model will depend on the specific application and available data.

Neither the ASME nor EN standards offer guidance on evaluating the remaining lifespan of pressure vessels and power boilers. These standards do not prescribe a particular calculation model for assessing remaining life. Instead, they provide recommendations on the relevant data to be considered and the factors to be evaluated.

Creep and fatigue are two different mechanisms that are taken into account when considering the behavior and failure of materials.

Creep refers to the time-dependent deformation that occurs in a material when it is subjected to a constant load or stress at elevated temperatures. This gradual deformation takes place over an extended period, often resulting in permanent deformation or even rupture of the material. Factors such as temperature, stress level, and material properties influence the occurrence of creep. It is particularly significant in applications where components experience high temperatures for prolonged durations, such as in power plants, boilers, and turbines.

On the other hand, fatigue is a failure process that arises when a material undergoes repeated cyclic loading, typically at lower temperatures. Fatigue failure is characterized by the accumulation and propagation of micro-cracks within the material due to the repetitive stress cycles. Over time, these cracks grow and can ultimately lead to sudden fracture or failure, even at stresses lower than the material's ultimate strength. Fatigue failure is commonly encountered in structures subjected to cyclic loading, including power plant components.

To summarize, creep is a time-dependent deformation mechanism that occurs under constant stress and elevated temperatures, whereas fatigue is a progressive failure caused by cyclic loading at lower temperatures. Although both mechanisms can lead to material failure, they originate from different loading conditions and exhibit distinct characteristics.

Danish Experience on Power Plant Lifetime Consumption

Danish legislation by Order no. 1977 states: *Pressure equipment designed with limited lifetime because of fatigue or creep effects shall latest before half used lifetime be evaluated to determine a programme of lifetime assessment.*

Creep

Component in creep range will normally be designed based on 200.000h creep rupture values. This implies that the expected lifespan has been determined based on 200,000 hours or approximately 22.8 years, assuming the applied stress and operating temperature align with the allowable stress and design temperature, respectively.

The real use of lifetime will be evaluated based on the rules in EN 12952-4 Annex A, as described above as Larson-Miller method. Calculated lifetime will significantly decrease by decreasing operation temperature but will also decrease with decreasing stress and verse versa.

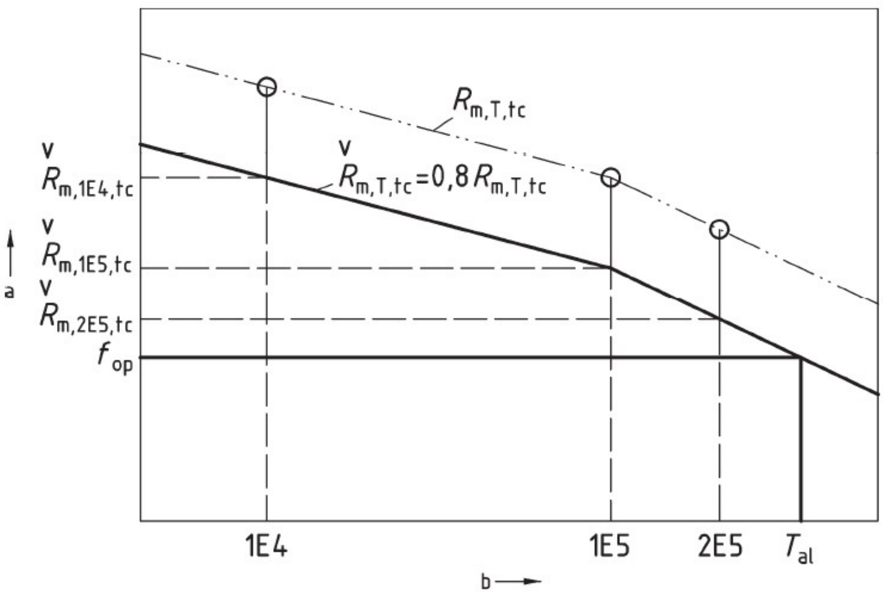

Figure 106. Figure A.1 from EN12952-4, T_{al} is theoretical lifetime.

The following Figure 107 is an example from Denmark that demonstrates the calculation of lifetime consumption based on actual operational data.

The KKS-numbers in the table represents:

HAH	Outlet boiler header.
HAJ	Internal boiler connecting piping.
LBA	Live steam piping.
LBB	Hot reheat piping.

The table provided calculates the lifespan of pressure vessels and power boilers based on recorded values of pressure and temperature over a given time period. In this scenario, it is assumed that the stress is solely derived from the internal pressure (known as hoop stress) and will vary directly with changes in pressure. The time period for calculations can range from one month to several years, depending on the availability of data. To obtain more precise results, the time step can be decreased to one minute or five minutes.

It is important to note that if the pressure and temperature values are at their design levels (PS and TS), the calculated lifespan for one hour will be exactly one hour. However, if the pressure and temperature values are lower than the design levels, the lifespan will increase accordingly.

Calculated actual consumed lifetime based on historical data						
Matr.standard:	EN10216-2	Point no:				
Steel no..	1.4922	Steel name:	X20CrMoV11-1			
					X % PS	
Largest stress, σ	Allowable	89,6	N/mm2			
σ ved X % PS					80	
Stress drop at X % PS		80,0	%			
T_{op} =		1,0	timer			
Ao of lows =		803				
No of hours =		803	timer			
Used lifetime in period =		181	timer			
Actual used lifetime in pct. in the period =		**22,6**	%			
Temperature addment =		0,0	°C			
Sum of lifetime / ΔDc			79405,4	9,06E-02		
	Temperature, °C	Temperature, °C	Lifetime	ΔDc	P_{drift} / $P_{bereg.}$	σ
Date Time	**AMV3-LBA10+20-CT002XQ35**	**AMV3-LBA10+20-CP001XQ35**	hours	%	%	%
Design values:	*550*	*274*	1,0	5,00E-04	100,00	100,0
01-02-10 12:54:55	541,7	229,8	3,5	1,41E-04	83,85	83,9
01-02-10 13:54:55	542,4	226,4	3,6	1,39E-04	82,62	82,6
01-02-10 14:54:55	540,9	234,6	3,4	1,46E-04	85,60	85,6
01-02-10 15:54:55	541,7	237,0	3,2	1,58E-04	86,51	86,5
01-02-10 16:54:55	541,8	235,9	3,2	1,57E-04	86,09	86,1
01-02-10 17:54:55	542,1	232,0	3,3	1,50E-04	84,67	84,7
01-02-10 18:54:55	540,8	230,0	3,7	1,35E-04	83,93	83,9
01-02-10 19:54:55	541,5	230,1	3,6	1,41E-04	83,96	84,0
01-02-10 20:54:55	539,7	227,3	4,1	1,22E-04	82,95	82,9
01-02-10 21:54:55	537,8	235,7	4,2	1,20E-04	86,01	86,0
01-02-10 22:54:55	540,5	226,1	4,0	1,25E-04	82,54	82,5

Figure 107. Calculated use of lifetime based on hour values for pressure and temperature.

When considering piping operating in the creep range, it is important to note that the hoop stress may not always be the most critical factor. A flexibility calculation should be conducted to identify significant longitudinal stresses resulting from primary loads such as dead weight and pressure, as well as secondary stresses arising from thermal expansion. In the EN13480-3 standard, these stresses are referred to as S5 stresses. It is critical to evaluate and address these stresses to ensure the integrity and reliability of the piping system.

In the table below several systems has been calculated both in relation to hoop stress and in relation to longitudinal stresses. Test method for detecting creep damage will be metallographic replication.

	Calculated lifetime				Lifetime assessment
	Design Hoop stress	Stress at operation data			
		Allowable stress	EN13480-3 S5	von Mise	
KKS no.	år	år	år	år	NDT neccessary
HAH81+85	39	48			yes
HAH90BR010	62	36			yes
LBA10BR010	33	67	173	75	yes
LBA10BR601	22	67	89	82	yes
LBA20BR010	33	49	57	38	yes
LBA20BR601	22	49	32	38	yes
LBA30	36	58	81	72	yes
HAJ11+15	78	3262			no
HAJ21+25	78	3262			no
HAJ31+35	251	81			no
HAJ40	265	83			no
LBB10	56	111	634	357	no
LBB20	56	57	304	189	yes
LBB11	27	111	326	275	no
LBB21	27	57	78	130	yes
LBB30	30	78	204	177	no

Figure 108. Calculated lifetime based on operation data for a Danish power plant unit.

In this particular scenario, the emphasis has been placed on systems where the calculated lifespan is below 80 years, denoted by the red numbers. Through these calculations, critical components have been identified, and a programme has been developed for the assessment of their remaining lifespan. The purpose of this programme is to evaluate the lifetime and condition of these components in order to ensure their continued safe and reliable operation.

Fatigue

Use of lifetime in relation to fatigue will be evaluated based on the rules outlined in EN 12952-4 Annex B and EN 12952-3 Annex B and C. Detecting fatigue damage through non-destructive testing (NDT) methods is challenging until a crack actually manifests. The most effective approach is to conduct a fatigue calculation utilizing real-time operational data.

Figure 109 and Figure 110 shows the actual recorded data for the plant and the boiler drum. Figure 109 indicates that the boiler experiences frequent starts and stops on a daily basis, leading to variations in drum pressure and temperature gradients within the boiler drum's wall thickness.

The two temperature gradient measurement points, HAD01CT0001_XJ03 and HAD01CT0002_XJ03, are typically expected to fluctuate around zero. However, there appears to be an offset between the two measurement points, as well as both points showing an offset in relation to zero. This suggests a potential calibration issue that needs to be investigated.

The calculations provided assume that the recorded temperature difference shown in Figure 110 accurately represents the real temperature difference amplitude. Based on this assumption, a lifetime consumption can be calculated.

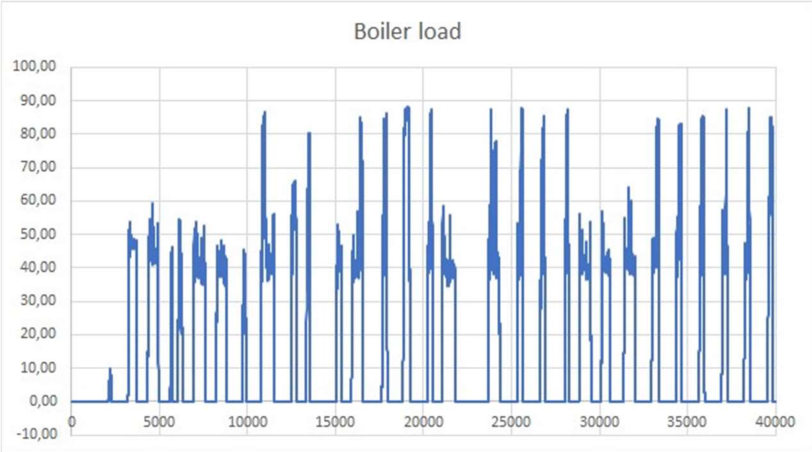

Figure 109. Boiler load one month, 7 min. values.

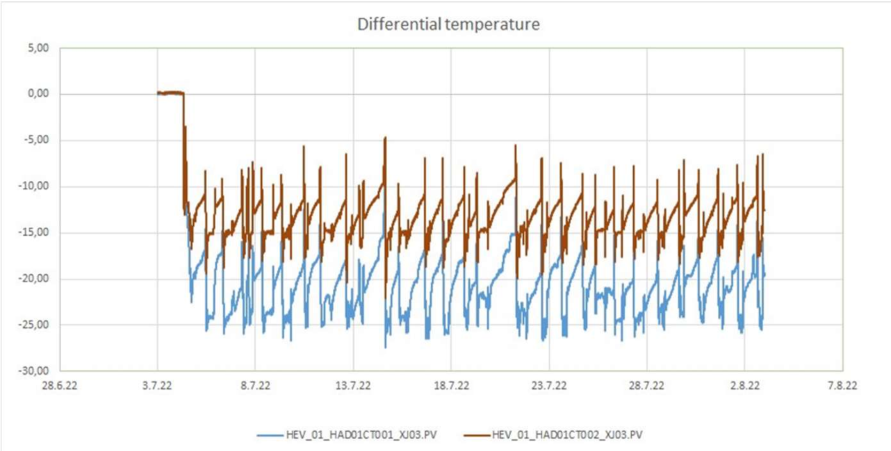

Figure 110. Boiler drum differential temperature in two points, end and middle.

Figure 111 shows a lifetime calculation based on fluctuating temperature gradients in the boiler drum. The operation time period in this case is one month as indicated on Figure 109 and Figure 110. The table calculates the max. allowed temperature difference for each load regime where the considered time interval is assumed to be representative of the entire period.

EN12952-3, Annex C, Tabel C-2, calc. of max allowable temp. gradient							
Example 2 Calculation of the fatigue loading, in accordance with clause 13							Inputfelt
and annex B: Calculation of the admissible temperature gradient							
This calculation shall be carried out for a different number of cycles such that SUM (n/N) < = 1 if the load							
regime is specified. If the load regime is not specified see 13.1.2							
Drawing No.: HEV 57.20.17845/0.100		**HAD01**					
Materialestandard:							EN10028-2
Steelno.							ATM NiMoV
Steelname:							WB314
Material properties from EN 12952-3/EN13480-3 Annex D							
Design levetid	40	years					
Data fra:							
Load regime no:				1	2	3	
cycle type:				4.7.22	2 no's./month	28 no's./month	
Calculation pressure	pc	barg		140			
Calculation temperature	tc	°C		337			
Operating pressure	po	barg		118	118	118	
min. cyclic pressure	pmin	barg		0	18	35	
max. cyclic pressure	pmax	barg		118	118	118	
min. cyclic temperature	tmin	°C		20	200	240	
max. cyclic temperature	tmax.	°C		330	320	320	
water/steam, water=true, steam=false				FALSE	FALSE	FALSE	
Is magnetite created? yes=true, no=false				FALSE	FALSE	FALSE	
Notch factor	C_k			1	1	1	
Numaber of cycles in a month	N_month			1	2	28	
Number of cycles	N			480	960	13440	
Usage	Util			0,4	0,4	0,4	
N / Util	Nas			1200	2400	33600	
Outside diameter of the drum	do	mm		1960	1960	1960	
Mean wall thickness of the drum	ems	mm		80	80	80	
Outside diameter of the branch	dob	mm		168,3	168,3	168,3	
Mean wall thickness of the branch	emb	mm		20	20	20	
Alpha_m	α_m			3,1	3,1	3,1	
R_vt EN12952-3 sec. 5.5 more accurate	vt	°K/min		2,3	2,2	2,2	
R_vt EN12952-3 sec. 5.5 conservative	vt	°K/min		0,0	0,0	0,0	
Factor for partition of the thermal stress range	g_s			0,5	0,5	0,5	
dt1 (begin of start up) = (f1 - Sp,min)/W (13.4-12a)	dt1, start up	°K	1	-42,16	-35,71	-15,14	
dt1' (end of start up) = (f1 - Sp,max)/W (13.4-12b)	dt1', start up	°K	2	-106,27	-89,57	-59,77	
dt2' (end of shut down) = (f2 - Sp,min)/W (13.4-12d)	dt2', shut down	°K	3	106,27	89,57	59,77	
dt2 (begin of shut down) = (f2 - Sp,max)/W (13.4-12c)	dt2, shut down	°K	4	42,16	35,71	15,14	
vt1 (begin of start up) = dt1 × V (13.4-13)	vt1, start up	°K/min	5	10,62	8,72	3,66	
vt1' (end of start up) = dt1' × V (13.4-13)	vt1', start up	°K/min	6	26,77	21,86	14,46	
vt2' (end of shut down) = dt2' × V (13.4-13)	vt2', shut down	°K/min	7	-26,77	-21,86	-14,46	
vt2 (begin of shut down) = dt2 × V (13.4-13)	vt2, shut down	°K/min	8	-10,62	-8,72	-3,66	

Figure 111. Calculated max. allowable temp. gradient for a given load regime in a certain time.

Figure 112 show the calculated lifetime for each load regime when max temperature gradient amplitude is applied.

Drawing No.:	**HEV 57.20.17845/0.100**			Cycles	LoadCycles	Use of
HAD01	Data: HEV_01_HAD01_03-07-2022--03-08-2022_with Tsat.xlsx					Lifetime
					Max	
Δt (dt1)*f(gs)	Load regimes					
°C	4.7.22	2 no's./month	28 no's./month	Σn	N	n/N
-42,16	1			1200	1200	1,00E+00
-35,71		2		2400	2400	1,00E+00
-15,14			28	33600	33600	1,00E+00
Calculated use of lifetime where 1,0 is 100% use of lifetime						**3,00E+00**

Figure 112. 100% use of lifetime for each load regime when max temperature gradient amplitude is applied.

Figure 113 show the calculated lifetime for the boiler drum when recorded temperature amplitudes are applied.

Drawing No.: HEV 57.20.17845/0.100				Cycles	LoadCycles	Use of
HAD01	Data: HEV_01_HAD01_03-07-2022--03-08-2022_with Tsat.xlsx					Lifetime
					Max	
Δt (dt1)*f(gs)	Load regimes					
°C	1200	2400	33600	Σn	N	n/N
9,00	1			1200	28172	4,26E-02
8,00		2		2400	57289	4,19E-02
7,00			28	33600	103705	3,24E-01
Calculated use of lifetime where 1,0 is 100% use of lifetime						**0,41**

Figure 113. Calculated use of lifetime when recorded temperature amplitude is applied.

I the actual case more months with recorded operation data has been evaluated and based on these an overall lifetime consumption can be predicted for the boiler drum in operation until today.

Monitoring of lifetime consumption:

The increased flexibility of the coal fired power plants has led to increased number of start-ups and load changes, including steeper gradients. Additionally, once-through boilers (specifically Benson boilers) transition from Benson mode to circulation mode. As a result, there is a need to monitor the lifetime consumption of critical thick-walled components within the boiler.

The DCS suppliers for the power plants in Denmark offers packages for monitoring and prediction of critical component exhaustion (fatigue) in accordance with the European EN 12952-4 specification and the German TRD 301 and 508 rules. Examples of such packages include ABB Optimax BoilerLife Monitoring and Siemens Leda (**Le**bens**da**uer).

The calculations require preferably three representative measuring points, pressure, temperature at the inner surface and middle wall. Alternatively, a pressure and a medium temperature measurement can be used.

The results of the calculations are used for monitoring periods or incidents where the lifetime consumption has been increased. Based on these findings, changes in procedures and/or regulations has been implemented to mitigate excessively lifetime consumption in the future.

Example of extended lifetime consumption

In the Daily Evaluations Report for the Live Main steam pipe LBA12 (Nordjyllandsvaerket unit 3) it was discovered that Y piece LBA12 had an abnormal high Total exhaustion of 0,18 % (21,74%-21,56%) on the 5/1 where there was a turbine trip.

OPTIMAX
BoilerLife Reports

Daily Evaluations Report
Nordjyllandsvaerket Unit 3

Page: 1 of 5 — 06/12/2023 10:16:22

Tag Name (KKS) LBA12
Evaluation from 01/01/2023 00:00:00
to 06/03/2023 00:00:00

Calculation ID	Date/Time of Calculation	Fatigue without Classification	Fatigue with Classifiction	Creep without Classification	Creep with Classification	Due to Residual Extremes	LCF Due to Ref. Comp.	Creep Due to Ref. Comp.	Total Exhaustion [%]
6038	2023-01-01	2.202494	2.204520	19.272855	19.167200	0.089621	0.000000	0.000000	21.564970
6039	2023-01-02	2.202494	2.204520	19.272958	19.167318	0.089621	0.000000	0.000000	21.565073
6040	2023-01-03	2.202494	2.204520	19.273205	19.167583	0.089621	0.000000	0.000000	21.565320
6041	2023-01-04	2.202494	2.204520	19.273517	19.168060	0.089621	0.000000	0.000000	21.565632
6042	2023-01-05	2.202494	2.204520	19.273755	19.168505	0.089621	0.000000	0.000000	21.565871
6043	2023-01-06	2.227194	2.221999	19.273941	19.168894	0.244435	0.000000	0.000000	21.745571

Figure 114. Daily Evaluations Report, LBA12.

An examination of the incident showed that the trip resulted in big temperature difference between inner wall temperature LBA12CT101 (red curve in Figure 115) and middle wall temperature LBA12CT102 (blue curve in Figure 115) above from normal 8°C to 100°C in few minutes.

In the following start-up the steam temperature LBA12CT901 (green curve in Figure 115) increased with 3,5 °C/min. which led to big differences in material temperatures up to 50°C.

Figure 115. Boiler and turbine trip 5/1, Material- and steam temperatures LBA12.

8.2.2.9. *Summary of the findings of 1st and 2nd low load test at Raichur*

Air-coal ratio

The air-coal ratio was tested on the 2nd day of the 2nd test and found to have a significant impact on the flame quality. Hence, the flame quality during the first test could probably had benefited from lowering the air-coal ratio from an average of ca. 2.7.

- The PA flow should optimally be controlled by the DCS system and follow the nominal curve.

It's advisable to conduct more tests to confirm the optimal air-coal ratio curve.

Mill in- and outlet Temperatures

The in- and outlet temperatures vary between the mills which implies different conditions within the mills. The different conditions can be several:

- Different wear and operating time since last overhaul.
  Each mill may have undergone maintenance or overhaul at different times, resulting in variations in wear and performance.
- Different inlet PA temperature.
  This can lead to differences in coal drying and combustion efficiency.
- Different air/coal ratios.
  Leads to varying residence time and differences in coal drying and combustion efficiency.
- Different classifier wear as recirculation setting.
- This can lead to variations in pf. size distribution and hence combustion behavior.

On one occasion, in the 2nd test, the outlet temperature for mill "C" reached 90°C which triggered the temperature control to reduce the inlet temperature with a steep downward ramping. An optimized control system can and should prevent such excessive temperature fluctuations.

During the tests, it became evident that in the wet monsoon season, raising both mill inlet and outlet temperatures is necessary for effective drying due to increased moisture in combustion air and coal. However, increasing mill temperature from 90 to 100°C poses fire risks. Consultation with BHEL, the OEM, is advised for safety and guidance.

- The mill outlet temperature shall be as high as possible to increase pf. dry-out.
- The mill temperature control needs to be optimized.

It's advisable to conduct more tests during the wet monsoon season to establish the necessary mill temperature and pf. dry-out.

Air Preheaters

To raise the inlet temperatures effectively, it is important that the air preheater cold bypass can be fully closed. During the second test, there were difficulties in achieving this because the dampers were requested to close but were unable to do so due to damper leakages. This issue concerning the damper leakages can hinder the control of inlet temperatures and impact the overall combustion process. It is suggested that this issue is addressed during the normal maintenance outage.

- The PA bypass dampers needs to be maintained.

SCAPHs

The non-operational Steam Air Preheaters (SCAPHs) in the unit pose challenges, especially during expected low loads. If SCAPHs were operational, they could raise flue gas temperatures, preventing corrosion risks. Therefore, it is suggested to

- Maintain the SCAPHs and use them in low loads.

Coal Dust distribution

There is a significant problem with the pf. distribution from the coal mill to the burners, with deviations as high as 47%. The primary implication of this problem is that the intended air/coal ratio is not realized, which, in turn, results in suboptimal combustion, potentially leading to an unstable flame and decreased overall efficiency in the combustion process.

To mitigate this problem it is imperative to balance out the distribution of pf. However, the unit lacks the necessary equipment to perform this operation effectively. Hence, we propose to

- Install new adjustable coal balancing devices in the coal pipes.

The solution is not straightforward and will have to be carefully analyzed. Adjustable orifices, modifications to the classifier, and anti-roping inserts are all potential components of the solution.

It is recommended to engage BHEL (Bharat Heavy Electricals Limited) in this project, due to their expertise and knowledge regarding this technology.

Coal Dust Fineness

During the testing, the fineness of the pf. was slightly below the anticipated level, additionally, a significant variation among the coal pipes was identified. It's important to note that roller pressure is equally significant in the grinding process and requires testing.

Therefore, it is proposed:

- Conduct more extensive tests to determine the optimal classifier setting for recirculation more definitively.
- Conduct extensive testing to determine the optimal roller pressure for attaining better pf. fineness.

Flame Signals

During both tests, notable variations in flame intensity levels were evident, accompanied by intermittent flickering. These observations can likely be attributed to the previously mentioned issues, including problems with pulverized fuel (PF) distribution, insufficient fineness, the absence of pf. dry-out, and potential roping. However, it is important to consider that the problem may also be associated with the flame scanner equipment. Hence:

- Verify flame scanner signals.

The verification process should start with visual inspections and then advance to equipment maintenance and calibration. Ultimately, it may be necessary to consider replacing the current scanners with more advanced and modern versions.

Controls

Controllability is of utmost importance in a coal-fired thermal power plant, especially during low load operation and during load ramping.

The challenges with controllability can be traced back to two distinct underlying factors:

3. Inadequate control loop designs
4. The deterioration of equipment due to wear and tear.

For the controls to function effectively, it is imperative that the equipment operates in accordance with its intended design.

During both tests it has been observed that the following controls needs to be modified and optimized in order to function effectively during low loads and ramping:

- Drum level control.
- SH, RH temperature control.
- Combustion air and fuel coordination control.
- Mill ramping control.
- Mill temperature control.

It is highly recommended to optimize the controls to enable unit load control through few set points in the unit control system. These controls, when properly implemented, will contribute to the efficient and optimized operation of the system.

9. Roadmap for Reaching Low Load and Ramp Rates

9.1. Introduction

During 2022 and 2023, a potential of power plant flexibility was explored, and the study of the operational flexibility for two power plants, namely Ramagudam Unit 7 and Raichur Unit 3, was performed. In 2023, the low load and ramp rate tests were performed on two occasions in order to achieve 40% of load. The initial tests were performed in January and February 2023, followed by subsequent tests in August and September 2023. During the first round, "good" quality coal was assumed for testing, whereas the second round replicated conditions with "poorer" quality coal, simulating the challenges of the monsoon season, which included the presence of wet coal and moist combustion air. To summarize, based on the tests conducted, the unit demonstrated its capability to achieve a 40% load using coal of relatively good quality. Although the ramp rates were not fully met, the unit exhibited a highly favourable response during the testing period.

The preliminary findings and conclusions derived from both rounds of testing exhibited a remarkable level of consistency and unanimity which suggests a high degree of reliability in the results obtained. Moreover, these findings are anticipated to serve as a reliable benchmark for evaluating the performance of comparable power plants across India. By capturing the nuances of varying coal qualities and environmental conditions, the insights gathered from these tests are summarized to offer valuable guidance for enhancing operational efficiency, optimizing resource utilization and implementing best practices within the broader context of the Indian power generation landscape. Thus, the comprehensive nature of the testing process and the alignment of its outcomes provides a valuable reference point for stakeholders seeking to improve the performance and sustainability of similar power plants nationwide.

9.2. Pilot Tests

The pilot projects in both Ramagundam and Raichur followed the same roadmap for success, presented visually in the image below, as well as performed preliminary steps.

The pilot projects undertaken in both Ramagundam and Raichur adhered to a common roadmap designed to ensure success. This roadmap, illustrated visually in image below, served as a guidance framework for navigating various stages of project implementation. Additionally, the projects commenced with the execution of preliminary steps aimed at laying a solid foundation for subsequent activities. These initial steps encompassed tasks such as comprehensive feasibility studies, stakeholder consultations, resource assessments and risk analyses. By following this meticulously crafted roadmap and diligently completing the preliminary steps, the pilot projects were able to establish a robust framework for their respective objectives while providing clarity, alignment and efficiency throughout the implementation process.

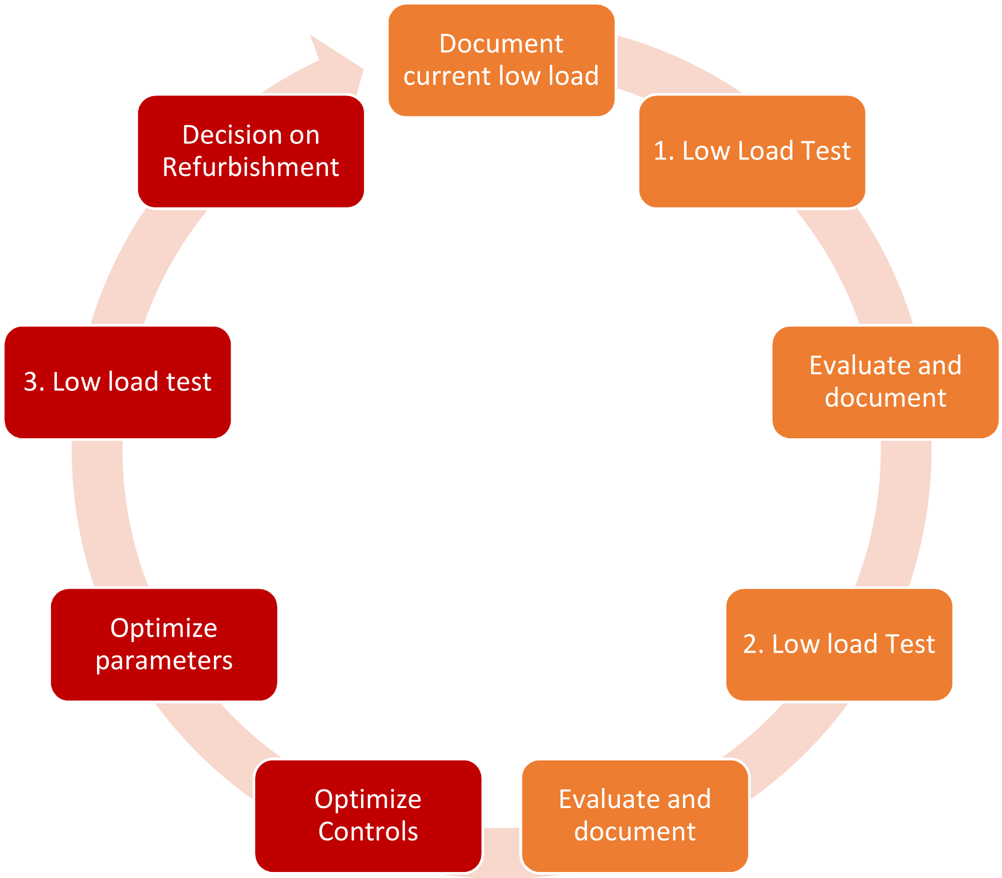

Figure 116. Implementation process

The last four steps remain to be performed, per February 2024.

Preliminary steps

Before conducting any tests, it is imperative to ensure that certain prerequisites are met to uphold the integrity and reliability of the testing process. These prerequisites serve as foundational elements that contribute to the accuracy and effectiveness of the testing procedure. Key prerequisites include:

1. **Clear objectives.**
   Define the specific goals and objectives of the test to ensure alignment with desired outcomes and expectations.
2. **Documented test plan.**
   Develop a comprehensive test plan outlining the scope, methodology, resources and timeline.
3. **Roles and responsibilities.**
   Clear definitions of involved personnel, as well their roles and responsibilities in the pilot tests, which include, and are not limited to:
   - Management

- Control room personnel
- Control Engineers and I&C Technicians
- Maintenance personnel
- Supervisors
- Others

4. **Risk assessment.**
   Identify potential factors that potentially pose a risk for limiting the test or tripping equipment and ensuring the well-being of personnel and the environment during the testing process. The risk assessment considers the following aspects.
    - Fuel quality
    - Load control stability
    - Feed-water flow stability
    - Low RH temperature
    - Burner flame detection
    - Fan limitations
    - Furnace pressure fluctuations
    - FW pump limitations
    - …
5. **Plant readiness.**
    - Verification of ability of the power plant to operate efficiently and reliably at the required load points. Responsible maintenance personnel are required to report any damage, wear or malfunctions of key equipment.
    - Ensuring that necessary coal, pulverized fuel (P.F.), and UBC sample equipment are readily available and functioning properly.
    - Ensuring that the data sampling system is working properly, and the necessary reports and tag-numbers are included. The time resolution shall not be more than 1 minute.
    - Ensuring the proper functioning of the data sampling system and the ability to transfer data to Excel format is essential for efficient data management and analysis.

Document the current low load

The first step is to document the current low load. This is a very important step that will provide a reference point for all the following steps, i.e. the benchmark.

Ideally, the test execution should adhere to the outlined procedure for the 1st low load test. Nevertheless, in Ramagundam and Raichur, the plant operators conducted these tests independently, without assistance from DEA and COWI.

1st low load test

Performing the first low load test requires a methodical and cautious approach, with readiness to address unforeseen challenges.

The 1st test shall be performed with good quality coal to rule out combustion problems caused by wet coal. Moreover, it shall be performed very slow and cautiously. If necessary, oil support can be used. The defined low load goal may not be obtainable in first attempt because of unforeseen difficulties. In that case different operating parameters can be adjusted and the test can be repeated.

When reducing loads, it is preferable to maintain a relatively high mill load rather than reducing the number of operating mills. Smooth transitions without compromising the unit load are preferred when taking mills out of operation. By prioritizing a high mill load and implementing smooth transitions, the operators can effectively manage load variations while maximizing the unit's combustion efficiency and stability.

The experience gathered from the conducted tests indicates that operating the unit in a manual-automatic mode is necessary due to many controls not being specifically designed for low loads. In manual-automatic mode, operators have the flexibility to intervene and make manual adjustments as needed, while still leveraging automatic controls for routine operations. This mode of operation allows for greater adaptability to varying load conditions, particularly at lower loads where standard controls may not be optimized.

The following parameters are foreseen to be in play:

1. **Slow and Cautious Testing:**

   - Initiate the low load test gradually and cautiously while allowing sufficient time for the plant to adjust to the new operating conditions.
   - Reducing the load must be done in a number of minor steps. After each reduction, it should be allowed to have at least 30 minutes stabilization.
   - Monitor key parameters closely throughout the test to identify any abnormalities or deviations from expected values.

2. **Utilization of Oil Support**:

   - If necessary, utilize oil support to facilitate stable operation during the low load test. Oil support can provide additional stability and control, especially during initial test phases or in the presence of operational challenges.

3. **Adjustment of Operating Parameters**:

   If the defined low load goal is not initially reachable due to unforeseen difficulties, personnel should be prepared to adjust various operating parameters to improve the performance.

Consider adjusting the following parameters based on operational requirements and performance feedback:

- Number of Operating Coal Mills:
  Adjust the number of coal mills in operation to optimize mill load and ensure stable operation.
- Mill Temperature:
  Monitor and adjust mill temperature to maintain optimal conditions for coal grinding and combustion.
- PA Flow to Coal Flow Ratio:
  Optimize the ratio of primary air (PA) flow to coal flow to achieve efficient combustion and stable flame conditions.
- Classifier Vane Settings:
  Fine-tune classifier vane settings to control particle size distribution and optimize coal fineness.
- Burner Elevation Levels:
  Adjust burner elevation levels to achieve proper coal-air mixing and combustion stability.
- SCAPH operation:
  The Steam Coil Air Pre-Heater (SCAPH) can be engaged when flue gas temperatures are too low or when extra heat is needed to ensure effective drying of pulverized fuel (PF) in the coal mills, particularly during the monsoon season.

4. **Iterative Testing and Adjustment**:
   Conduct iterative testing, making incremental adjustments to operating parameters as needed, and repeating the test to evaluate the effectiveness of changes. Continuously monitor and analyse performance data to assess the impact of parameter adjustments and identify opportunities for further optimization.

5. **Sampling**
   During the test, a number of samples are required to be taken:

- Raw coal sampling.
  An ultimate fuel analysis is required for data processing.
- P.F sampling.
  Samplings from each coal pipe from each operating coal mill is required.
  The sampling must be performed according to standards that enables calculation of p.f. distribution among the coal pipes.

The samplings shall be analysed for size distribution by sieve tests and a proximate fuel analyse performed to establish dry-out.

- UBC – Unburned Carbon

  Samples are required from bottom and fly-ash.

6. **Focus points**

   During the test, the project team shall focus on the following:

   - What are the challenging issues?
   - Are the flame scanner signals adequate?
   - Does flame flicker occur?

     By manual inspection of flames and scanner signals.
   - Are the unit operating in stable manner?
   - Are the parameters achieved?
     - SH/RH temperatures
     - Mill temperatures
     - PA/coal ratio
     - Drum level
     - O_2 ratio
     - Emissions NO_X and CO
     - Flue-gas temperature
     - Any malfunctions?

1st Ramp Rate Tests

The ramp rate tests were performed after 1st day low load tests. These tests involved incrementally decreasing and increasing loads, transitioning from 100% to 40% load and subsequently returning to 100% load respectively.

The tests were conducted with mainly manual operation of feeders, mills and drum level.

The tests aimed for testing the ramp rates in three different load regimes according to the new regulations from CEA:

- 3%/min from 70% to 100% of the maximum capacity
- 2%/min from 55% to 70% of the maximum capacity
- 1%/min from 40% to 55% of the maximum capacity.
-

The ramp rates were achieved in a combination of mill load change and taking mills in/out of operation.

Evaluate and document the 1st low load test

The evaluation and documentation of the 1st low load test shall focus on the combustion system and the identified problems during the test. Document all test procedures, parameter adjustments, and performance observations systematically. Prepare detailed reports summarizing the outcomes of the low load test, including any challenges encountered, adjustments made, and recommendations for future testing or operational enhancements.

2nd low load test

The second test shall be conducted with lower quality coal, particularly in an area prone to monsoon conditions which presents an opportunity to evaluate the plant's performance under more challenging operating conditions.

The comprehensive testing protocol described above for the 1st test shall be consistently applied. Adhering to this meticulous testing approach for the second evaluation with lower quality coal enables an effective assessment the plant's performance under more demanding operational circumstances. This consistency facilitates the identification of areas for enhancement and optimization within the plant's operations.

A thorough test report, mirroring the format and detail of the first test report, is essential for documenting findings, insights, and recommendations arising from the second evaluation.

2nd Ramp Rate Tests

Performed in line with the 1st test.

Optimize Controls

One of the key insights gathered from the tests conducted at Ramagundam and Raichur, as well as from the experience gained at Danish power plants, is the importance of optimizing controls to operate efficiently at lower loads than the units were originally designed for.

In order to enable the unit to operate in automatic mode during low loads and ramping, it is imperative to review the following control loops as a minimum:

- Master unit control – fuel/load coordination.
- SH and RH spray temperature control.
- Burner tilt control.
- Boiler drum level control.
- Oxygen control and fuel/air coordination.
- Flue gas temperature control using SCAPH.
- Ramping control.
- Mill outlet temperature control.
- Furnace pressure control

Optimize parameters

Experience indicates that significant improvements can be achieved by optimizing combustion parameters. To ascertain whether the unit operates optimally or certain parameters can be further optimized, a series of tests must be meticulously planned and executed. These tests aim to assess the performance of the unit under various operating conditions and identify opportunities for enhancement. By systematically analysing combustion parameters such as fuel-air ratio, burner settings, flue gas composition and flame stability, valuable insights into the efficiency and effectiveness of combustion processes can be gained. Through iterative testing and adjustment, potential areas for optimization can be identified, leading to improved operational performance, reduced emissions and enhanced fuel efficiency.

- PA/coal ratio
- SA/TA ratio
- Grinding pressure
- Classifier vane setting
- Trimming of the p.f. distribution from the mills
- Mill temperature
- Ramp rates by taking mills in and out
- Ramp rates by reducing load – without taking mills in/out.

3rd low load test

The third test shall use normal quality coal and serve as the cornerstone for assessing the requirement for refurbishment. Ideally, this test will minimize manual intervention, ensuring a more streamlined evaluation process.

The test will adhere to the procedures outlined in low load tests 1 and 2, maintaining consistency with the comprehensive testing protocol established for the initial test.

3rd Ramp Rate Tests

The third test will be conducted in accordance with the procedures established in the first test. Whenever feasible, the tests will be operated using automated control systems. Additionally, efforts will be made to demonstrate a ramp from full load down to a minimum load of 40%. The plant will stabilize at minimum load before ramping back up to full load again.

Refurbishment

The conducted test serves as a robust basis for recommending several refurbishments. By thoroughly analysing the results and identifying areas for improvement, valuable insights are gained. These insights enable informed decisions regarding the implementation of upgrades or enhancements to the existing system. Additionally, the test findings provide a clear direction for optimizing performance, increasing efficiency, and ensuring the longevity of the equipment or facility.

As of February 2024, the preliminary findings from the tests conducted at Ramagundam and Raichur power plants are not yet conclusive. Further optimization of controls and parameters is required, and this will be documented in a third test before any final conclusions can be drawn.

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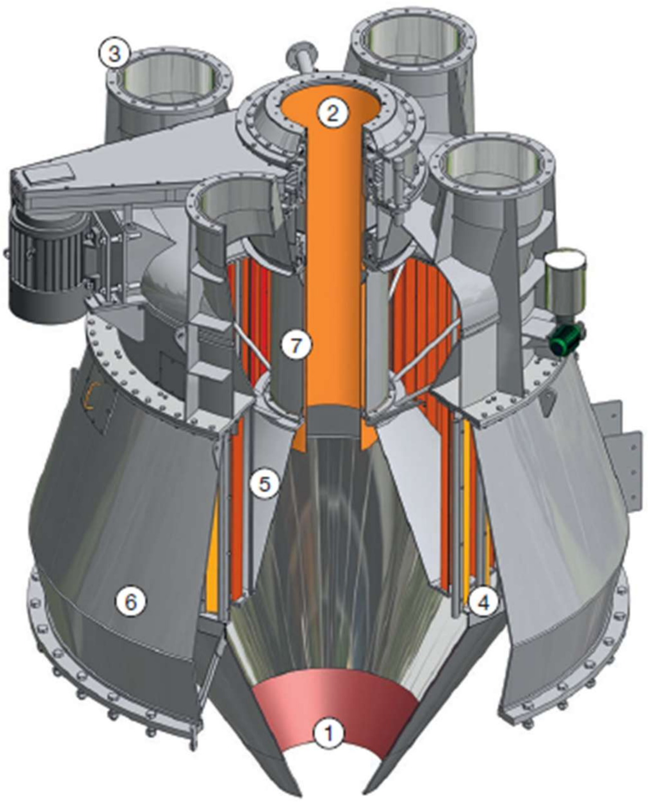
Appendix A –Loeche Dynamic Classifier

Loesche high efficiency dynamic classifier for the power industry

The ideal solution for optimised boiler performance...

① Grit cone
② Coal feed tube
③ Pulverised coal outlets
④ Guide vanes
⑤ Rotor with blades
⑥ Housing
⑦ Rotor shaft



- Steeper grain size distribution curve with reduced coarse end fraction material
- Reduced recirculation of fine product
- Improved boiler efficiency through reduction in unburnt carbon in ash content and NO_x emissions
- Improved mill operation for wider coal diet specification
- State of the art design suitable for retrofitting both vertical spindle and horizontal ball mills
- Flexible operation and response rate to mill load demand
- Turnkey solutions available

Dynamic Classifiers for Ho-Ping Power Plant

Appendix B – List of Power Plants

The selected units are highlighted with yellow.

S.No.	Utility	TPS Identified	Unit No. Identified	Unit Cap. (MW)
1	NTPC	Dadri TPS	Unit - 6	500
2	NTPC	Vindhayachal TPS	Unit -11	500
3	NTPC	Mouda TPS	Unit - 1	500
4	DVC	Mejia TPS	Unit - 8	500
5	GSECL	Wanakbori TPS	Unit - 4	210
6	GSECL	Ukai TPS	Unit - 6	500
7	APGENCO	Rayalaseema TPS	Unit - 1	210
8	PSPCL	Guru Hargobind TPP	Unit - 1 & 2	210
9	WBPDCL	Bakreswar TPS	Unit - 5	210
10	WBPDCL	Sagardighi TPP	Unit - 3	500
11	KPCL	Raichur TPS	Unit - 6	210
12	KPCL	Bellary TPS	Unit - 2	500
13	UPRVUNL	Parichha TPS	two units	2x210
14	MSPGCL	Bhusawal TPS	Unit - 4	500
15	MSPGCL	Parli TPS	Unit - 8	250
16	MSPGCL	Chandrapur TPS	Unit - 5	500
17	TSGENCO	Kothagudem TPS VI Stage	Unit - 11	500
18	MPPGCL	Sanjay Gandhi TPS	Unit - 2	210
19	NTPC	Ramagundam	Unit - 7	500

Appendix C – Chemistry department data analysis

Day 1: 28.02.2023 @300 MW @ 9.45 Hrs

UNBURNT CARBON

Unit	7	Limit
Bottom Ash (%)	1.24	2.00
Fly Ash (%)	0.21	1.00

COAL MILL FINENESS ANALYSIS

MILL C	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	102.39	1.6	10.7	24.0	63.7	87.7
Corner 2	59.50	0.6	6.0	12.5	80.9	93.4
Corner 3	115.05	2.0	13.4	23.8	60.8	84.6
Corner 4	100.97	2.8	13.0	21.9	62.3	84.2

MILL D	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	66.26	1.6	8.3	14.9	75.2	90.1
Corner 2	98.97	4.7	15.3	20.0	60.0	80.0
Corner 3	105.39	3.8	15.7	21.4	59.0	80.5
Corner 4	94.37	2.1	10.4	21.5	66.0	87.5

MILL E	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	95.26	0.5	7.5	21.7	70.3	92.0
Corner 2	57.52	0.2	3.9	13.3	82.6	95.9
Corner 3	92.81	0.6	8.8	23.5	67.1	90.6
Corner 4	60.77	0.4	7.2	16.8	75.6	92.4

MILL F	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	108.66	1.3	8.2	18.3	72.2	90.5
Corner 2	134.25	2.6	12.9	20.9	63.6	84.5
Corner 3	89.64	3.2	12.3	17.8	66.7	84.5
Corner 4	72.01	2.1	9.7	16.3	71.9	88.2

COAL AS RECEIVED ON AIR DRIED MOISTURE BASIS

Date	Air Dried Moisture (%)	Ash (%)	VM (%)	GCV (Kcal/Kg)
28.02.2023 @09:30hrs	6.80	39.83	26.52	3879

Day 1: 28.02.2023 @200 MW @ 16:45 Hrs

UNBURNT CARBON

Unit	7	Limit
Bottom Ash (%)	2.37	2.00
Fly Ash (%)	0.25	1.00

COAL MILL FINENESS ANALYSIS

MILL C	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	88.80	1.1	9.1	20.1	69.7	89.8
Corner 2	76.36	0.6	5.4	15.8	78.2	94.0
Corner 3	130.08	2.6	14.1	21.2	62.1	83.3
Corner 4	105.48	2.2	12.8	19.5	65.5	85.0

MILLD	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	55.78	1.2	6.3	12.5	80.0	92.5
Corner 2	107.44	4.4	15.3	20.3	60.0	80.3
Corner 3	111.50	3.5	14.6	20.5	61.4	81.9
Corner 4	128.89	3.9	14.5	22.3	59.3	81.6

MILLE	Coal Flow (T/Hr)	+50	+100	+200	-200	-100
Limit		<1%	<10%	<20%	>70%	>90%
Corner 1	106.25	0.5	6.9	21.6	71.0	92.6
Corner 2	90.89	0.6	8.5	19.6	71.3	90.9
Corner 3	101.75	1.2	12.9	21.0	64.9	85.9
Corner 4	98.06	1.0	10.6	19.9	68.5	88.4

COAL AS RECEIVED ON AIR DRIED MOISTURE BASIS

Date	Air Dried Moisture (%)	Ash (%)	VM (%)	GCV (Kcal/Kg)
28.02.2023 @16:30hrs	6.35	37.67	25.65	4160

UNIT 7 MILL COAL FINENESS ANALYSIS ON: 06.09.2023.

MILL/CORNR	Coal WEIGHT (gms)	+50 Limit<1%	+100 Limit<10%	+200 Limit<20%	-200 Limit>70%	-100 Limit>90 %
7C/1	90.76	1.6	9.9	21.0	67.5	88.5
7C/2	92.06	0.6	8.8	19.0	71.6	90.6
7C/3	63.24	0.9	9.8	19.0	70.3	89.3
7C/4	56.49	2.1	10.3	20.1	67.5	87.6
7D/1	78.39	2.0	10.4	20.3	67.3	87.6
7D/2	57.89	1.5	11.0	21.2	66.3	87.5
7D/3	50.20	1.2	12.2	22.0	64.6	86.6
7D/4	92.60	1.8	9.8	18.5	69.9	88.4
7E/1	81.78	1.8	9.8	19.8	68.6	88.4
7E/2	50.10	0.4	8.8	20.0	70.8	90.8
7E/3	89.58	0.9	10.2	21.0	67.9	88.9
7E/4	50.02	0.8	11.0	21.4	66.8	88.2
7F/1	97.77	0.8	8.8	21.0	69.4	90.4
7F/2	58.97	0.4	9.2	22.0	68.4	90.4
7F/3	50.26	0.8	9.8	21.2	68.2	89.4
7F/4	61.41	0.9	10.2	19.8	69.1	88.9
7E/1	50.12	1.1	9.1	19.8	70	89.8
7E/2	57.72	0.8	10.2	20.1	68.9	89
7E/3	77.30	0.6	10.8	21.0	67.6	88.6
7E/4	93.09	0.8	9.8	19.8	69.6	89.4
7F/1	50.12	1.2	10.8	21.2	66.8	88
7F/2	50.16	1.8	9.8	19.8	68.6	88.4
7F/3	50.20	2.0	10.8	21.0	66.2	87.2
7F/4	84.14	0.8	9.8	19.8	69.6	89.4

INTER OFFICE MEMO

From : Sr.Manager (CHEM)

To : AGM (EEMG)

Ref : 09/Chem/09/2023/1

Date : 11.09.2023.

Sub: - Boiler Efficiency test results of Unit - 7

Please find mentioned below are the Coal and Combustibles analysis results collected during the Boiler Efficiency Test of Unit -7 ON 05.09.2023

Coal as Fired

Parameters	Air Dry Basis	Total Moisture Basis
Moisture %	8.69	12.74
Ash %	36.48	34.86
Volatile matter %	24.69	23.59
Carbon (Diff) %	30.14	28.80
GCV (K.cal/kg)	3738	3572

Combustibles 05.09.2023

Fly Ash %	0.67
Bottom Ash%	1.47

Combustibles 05.09.2023

Fly Ash %	0.45
Bottom Ash%	2.97

Humidity

Dry Bulb °C	31
Wet Bulb °C	26

Appendix D – Boiler efficiency according to EN12592-15

INPUT				
Anlæg: Ramagundam unit 7				
Load point:			40%	40%
Søren Hallberg Olsen				
	EN12952-15 symbol	Unit	**28/2 2023**	**5/9 2023**
HP Steam:				
HT-steam flow	m_{ST}	kg/s	171,67	171,39
HT-steam temperature	t_{ST}	°C	541,1	537,5
HT-steam pressure	p_{ST}	bara	144,0	140,1
Feedwater temperature	t_{FW}	°C	213,3	210,9
Feedwater pressure	p_{FW}	bara	160,0	160,0
Reheat:				
Inlet flow	m_{ZI1}	kg/s	156,50	157,50
Inlet temperature	t_{ZI1}	°C	341,3	347,4
Inlet pressure	p_{ZI1}	bara	19,0	19,3
Outlet temperature	t_{ZI2}	°C	537,2	522,4
Outlet pressure	p_{ZI2}	bara	18,2	18,6
Spray flow	m_{EZI}	kg/s	1,1	2,3
Spray temperature	t_{EZI}	°C	135,0	135,0
Spray pressure	p_{EZI}	bara	21,0	21,0
Max usefull heat	Q_{NMax}	MW	1256,9	1248,4
Boiler type (Coal, Oil, Gas, Fluidbed)			Coal	Coal
Brændsel:				
Heating value - lower at reference temperatur	H_u	MJ/kg	16,000	14,000
Carbon	γ_C	%	41,62%	40,19%
Hydrogen	γ_H	%	3,00%	2,89%
Sulfur	γ_S	%	0,53%	0,51%
Oxygen	γ_O	%	8,32%	8,03%
Nitrogen	γ_N	%	0,80%	0,77%
Water	γ_{H2O}	%	9,20%	12,74%
Ash	γ_A	%	36,54%	34,86%
Volatiles	$\gamma_{Fl.B}$	kg/kg	0,249	0,236
Evaporated part of ash	v	kg/kg	0,050	0,500
Heat capacity	c_F	kJ/(kg K)	1,400	1,400
Temperature	t_F	°C	30,0	30,0
Combustion air:				
Inlet temperature at system limit	t_A	°C	38,0	31,0
Moisture in combustion air	x_{H2OLT}	g/kg	8,00	26,00
Leakage air (guess)	m_{falsk}	kg/s	10,00	10,00
Temperature leakage	t_{falsk}	°C	40,0	40,0
Flue gas:				
Temperature	t_G	°C	117,00	96,40
Oxygen (dry)	YO2T	dry-vol-%	11,1000	9,4000
CO	mCO	mg/nm^3	0,0000	0,0000
Ash & slag:				
Measured slag flow	m_{SL}	kg/s		
Measured flyash flow	m_{FA}	kg/s		
Unburned in slag	u_{SL}	kg/kg	0,0237	0,0222
Unburned in flyash	u_{FA}	kg/kg	0,0025	0,0056
Slag ratio	x_{SL}	kg/kg	0,400	0,400
Temperature of slag	t_{SL}	°C	1200	1200
Added heat - independend of fuel (mills)	P_{tilf}	MW	0,581	0,765
Removed heat - independend of fuel	Q_{EC}	MW	0,000	0,000

Calculation				
Usefull heat				
Enthalpy HP-steam	h_{ST}	kJ/kg	3432,8	3427,3
Enthalpy Feedwater	h_{FW}	kJ/kg	917,7	907,0
Enthalpy RH outlet	h_{ZI2}	kJ/kg	3552,2	3519,0
Enthalpy RH inlet	h_{ZI1}	kJ/kg	3120,4	3133,3
Enthalpy RH spray	h_{EZI}	kJ/kg	569,0	569,0
HP boiler	Q_{ST}	MW	431,758	431,958
Reheater	Q_{ZI}	MW	70,993	67,418
Usefull heat	Q_N	MW	502,751	499,376
Combustion				
CO2 in flue gas	x_{CO2}	kg/kg	0,1249	0,1398
H2O in flue gas	x_{H2O}	kg/kg	0,0369	0,0599
Specific dry volumetric flue gasflow	V_{GD}	nm^3/kg	8,7995	7,2426
Specific flue gas flow	μ_G	kg/kg	12,2604	10,5698
Specific combustion air flow	μ_A	kg/kg	11,6075	9,7441
Losses				
Specific integral heat capacity flue gas	c_{pG}	kJ/(kg K)	1,034	1,052
Specific flue gas loss	ΔJ_G	kJ/kg	1166,8	793,6
Specific CO loss	J_{CO}	kJ/kg	0,000	0,000
Ash & slag losses				
Calculation type 1,2,3,4			4	4
Entaschungsgrad	η_s	kJ/kg	0,3949	0,3960
Enthalpy slag loss	h_{SL}	kJ/kg	1957,1	1907,6
Enthalpy ash loss	h_{FA}	kJ/kg	159,8	244,8
Ratio of unburned combustibles	l_u	kg/kg	0,0071	0,0041
Specific slag loss	J_{SL}	kJ/kg	276,7296	135,2032
Specific ash loss	J_{FA}	kJ/kg	33,8888	26,0231
Specific slag and ash losses	J_{SF}	kJ/kg	310,6184	161,2264
Radiation- & convection losses				
Constant C	C	-	0,0315	0,0315
Losses	Q_{RC}	MW	4,654	4,632
Heat input				
Heating value (LHV)	Hu	MJ/kg	16,000	14,000
Specific integral heat capacity combustion a	c_{pA}	kJ/(kg K)	1,012	1,027
Specific enthalpy combustion air	J_A	kJ/kg	152,74	60,04
Leakages	Q_{falsk}	MW	0,2	0,2
Fuel heat capacity	c_F	kJ/(kg K)	1,400	1,400
Fuel enthalpy (heat)	h_F	kJ/kg	7,000	7,000
Total heating value	H_{uTot}	MJ/kg	16,274	14,125
Heat balance				
Burned fuel	m_F	kg/s	34,242	38,199
Applied fuel (m_F/(1-lu))	m_{Fo}	kg/s	34,487	38,357
Total losses	Q_{Ltot}	MW	55,242	41,106
Total heat input	Q_{ztot}	MW	557,993	540,482
Balance (Q_{Ztot} - Q_N - Q_{Ltot} = 0.0)	-	kW	0,000	0,000
Efficiency (EN12952-15)	**η**	**%**	**90,100**	**92,395**

Heat input with fuel				
Fuel heating value	$Q_{Fo} = m_{Fo}*H_u$	MW	551,789	537,001
Fuel sensible heat	$m_{Fo}*h_F$	MW	0,241	0,269
Combustion air	m_F*J_A	MW	5,230	2,294
Leakages	Q_{falsk}	MW	0,152	0,154
Heat input independent from fuel	P_{tilf}	MW	0,581	0,765
Total heat input	Q_{Ztot}	MW	557,993	540,482
Ash balance				
Slagge flow (incl. unburned)	m_{SL}	kg/s	4,8525	2,7265
Fly ash flow (incl. unburned)	m_{FA}	kg/s	7,2788	4,0897
Flow unburbed slag	$m_{SL} \cdot u_{SL}$	kg/s	0,1150	0,0605
Flow unburned fly ashe	$m_{FL} \cdot u_{FA}$	kg/s	0,0182	0,0229
Total ash with fuel	$m_{Bo}*\gamma_a$	kg/s	12,6015	13,3713
Ash balance (=0.0)		kg/s	0,0000	0,0000
Mass balance (fuel, air, flue gas og ash)				
Fuel	m_{Fo}	kg/s	34,4868	38,3572
Combustion air	m_L	kg/s	397,464	372,217
Total input	$m_{Bo}+m_{AS}+m_L$	kg/s	431,951	410,574
Flue gas	m_G	kg/s	419,820	403,758
Slag	m_{SL}	kg/s	4,853	2,726
Fly ash	m_{FA}	kg/s	7,279	4,090
Total output	$m_G+m_{SL}+m_{FA}$	kg/s	431,951	410,574
Mass balance (=0.0)		kg/s	0,0000	0,0000
Losses				
Flue gas loss (sensible heat)	Q_G	MW	39,952	30,315
Unburned CO loss	Q_{CO}	MW	0,000	0,000
Ash & slag losses:	Q_{SF}	MW	10,636	6,159
- sensible in fly ash	$m_{FA}*c_{FA}*(t_G-t_{ref})$	MW	0,563	0,245
- unburned in fly ash	$m_{FA}*u_{FA}*H_{uu}$	MW	0,601	0,756
- sensible in slag	$m_{SL}*c_{SL}*(t_{SL}-t_{ref})$	MW	5,702	3,204
- unburned in slag	$m_{SL}*u_{SL}*H_{uu}$	MW	3,795	1,997
Radiation- & convection losses:	Q_{RC}	MW	4,654	4,632
Fuel independent removed heat	Q_{ku}	MW	0,000	0,000
Total losses	Q_{Ltot}	MW	55,242	41,106
Specific losses				
Flue gas loss (sensible heat)	L_G	%	7,160	5,609
Unburned CO loss	L_{CO}	%	0,000	0,000
Ash & slag losses:	L_{SF}	%	1,906	1,139
- sensible in fly ash		%	0,101	0,045
- unburned in fly ash		%	0,108	0,140
- sensible in slag		%	1,022	0,593
- unburned in slag		%	0,680	0,370
Radiation- & convection losses:	L_{St}	%	0,834	0,857
Fuel efficiency (Q_N / Q_{FO})		**%**	**91,11**	**92,99**
HHV	HHV	MJ/kg	16,880	14,942
Fuel efficiency HHV		**%**	**85,56%**	**86,74%**

Appendix E – Boiler efficiency according to EN12592-15

INPUT				
Anlæg: Raichur unit 3				
Load point:			40%	38%
Søren Hallberg Olsen				
	EN12952-15 symbol	Unit	**5-3 2023**	**30-9 2023**
HP Steam:				
HT-steam flow	m_{ST}	kg/s	74,25	72,69
HT-steam temperature	t_{ST}	°C	540,6	543,2
HT-steam pressure	p_{ST}	bara	113,2	93,2
Feedwater temperature	t_{FW}	°C	202,9	202,4
Feedwater pressure	p_{FW}	bara	135,0	135,0
Reheat:				
Inlet flow	m_{ZI1}	kg/s	36	67,64
Inlet temperature	t_{ZI1}	°C	351,3	357,6
Inlet pressure	p_{ZI1}	bara	16,0	15,2
Outlet temperature	t_{ZI2}	°C	540,0	540,0
Outlet pressure	p_{ZI2}	bara	15,3	14,2
Spray flow	m_{EZI}	kg/s	0,8	2,1
Spray temperature	t_{EZI}	°C	143,0	143,0
Spray pressure	p_{EZI}	bara	21,0	21,0
☐ Blow down				
Max usefull heat	Q_{NMax}	MW	557,6	557,6
Boiler type (Coal, Oil, Gas, Fluidbed)			Coal	Coal
Brændsel:				
Heating value - lower at reference temperat	H_u	MJ/kg	12,970	10,710
Carbon	γ_C	%	31,80%	25,00%
Hydrogen	γ_H	%	2,70%	2,80%
Sulfur	γ_S	%	0,40%	0,50%
Oxygen	γ_O	%	11,80%	10,40%
Nitrogen	γ_N	%	0,60%	0,50%
Water	γ_{H2O}	%	10,50%	10,60%
Ash	γ_A	%	42,20%	50,20%
Volatiles	$\gamma_{Fl.B}$	kg/kg	0,223	0,216
Evaporated part of ash	v	kg/kg	0,050	0,050
Heat capacity	c_F	kJ/(kg K)	1,400	1,400
Temperature	t_F	°C	30,0	30,0
☐ Atomizing steam				
Combustion air:				
Inlet temperature at system limit	t_A	°C	43,0	42,5
Moisture in combustion air	x_{H2OLT}	g/kg	8,00	25,00
Leakage air (guess)	m_{falsk}	kg/s	10,00	10,00
Temperature leakage	t_{falsk}	°C	40,0	40,0
☐ Steam APH				
Flue gas:				
Temperature	t_G	°C	123,20	120,70
Oxygen (dry)	YO2T	dry-vol-%	9,30	13,25
Measured slag flow	m_{SL}	kg/s		
Measured flyash flow	m_{FA}	kg/s		
Unburned in slag	u_{SL}	kg/kg	0,0300	0,0384
Unburned in flyash	u_{FA}	kg/kg	0,0022	0,0060
Slag ratio	x_{SL}	kg/kg	0,400	0,400
Temperature of slag	t_{SL}	°C	1200	1200

Calculation				
Usefull heat				
Enthalpy HP-steam	h_{ST}	kJ/kg	3464,5	3491,9
Enthalpy Feedwater	h_{FW}	kJ/kg	870,3	868,1
Enthalpy blow down	h_{BD}	kJ/kg	1776,9	1776,9
Enthalpy condensat from steam APH	h_{SA}	kJ/kg	334,9	334,9
Enthalpy RH outlet	h_{ZI2}	kJ/kg	3561,1	3562,2
Enthalpy RH inlet	h_{ZI1}	kJ/kg	3148,8	3164,1
Enthalpy RH spray	h_{EZI}	kJ/kg	603,2	603,2
HP boiler	Q_{ST}	MW	192,622	190,735
Reheater	Q_{ZI}	MW	30,405	33,251
Blow down	Q_{BD}	MW	0,000	0,000
Steam APH (internal)	Q_{SA}	MW	0,000	0,000
Usefull heat	Q_N	MW	223,026	223,985
Combustion				
CO2 in flue gas	x_{CO2}	kg/kg	0,1469	0,0934
H2O in flue gas	x_{H2O}	kg/kg	0,0509	0,0593
Specific dry volumetric flue gasflow	V_{GD}	nm^3/kg	5,5781	6,9574
Specific flue gas flow	μ_G	kg/kg	7,9553	9,8518
Specific combustion air flow	μ_A	kg/kg	7,3562	9,3287
Losses				
Specific integral heat capacity flue gas	c_{pG}	kJ/(kg K)	1,046	1,056
Specific flue gas loss	ΔJ_G	kJ/kg	817,3	995,5
Specific CO loss	J_{CO}	kJ/kg	0,000	0,000
Ash & slag losses				
Calculation type 1,2,3,4			4	4
Entaschungsgrad	η_s	kJ/kg	0,3932	0,3921
Enthalpy slag loss	h_{SL}	kJ/kg	2165,0	2440,6
Enthalpy ash loss	h_{FA}	kJ/kg	155,1	278,4
Specific ash loss	J_{FA}	kJ/kg	38,2461	83,1487
Specific slag and ash losses	J_{SF}	kJ/kg	394,1850	569,1097
Radiation- & convection losses				
Constant C	C	-	0,0315	0,0315
Losses	Q_{RC}	MW	2,635	2,635
Heat input				
Heating value (LHV)	Hu	MJ/kg	12,970	10,710
Specific integral heat capacity combustion a	c_{pA}	kJ/(kg K)	1,012	1,027
Specific enthalpy combustion air	J_A	kJ/kg	134,05	167,58
Leakages	Q_{falsk}	MW	0,2	0,2
Tilført effekt til steamlufo fra ekstern steam	Q_{SA1}	MW	0,000	0,000
Enthalpi af forstøversteam	h_{AS}	kJ/kg	2853,5	2853,5
Specifik tilført effekt med forstøversteam	J_{AS}	kJ/kg	0,000	0,000
Fuel enthalpy (heat)	h_F	kJ/kg	7,000	7,000
Total heating value	H_{uTot}	MJ/kg	13,261	11,142
Burned fuel	m_F	kg/s	18,715	23,645
Applied fuel (m_F/(1-lu))	m_{Fo}	kg/s	18,932	24,214
Total losses	Q_{Ltot}	MW	25,307	39,629
Total heat input	Q_{ztot}	MW	248,333	263,614
Balance (Q_{Ztot} - Q_N - Q_{Ltot} = 0.0)	-	kW	0,000	0,000
Efficiency (EN12952-15)	η	**%**	**89,809**	**84,967**

Heat input with fuel				
Fuel heating value	$Q_{Fo} = m_{Fo}*H_u$	MW	245,540	259,329
Fuel sensible heat	$m_{Fo}*h_F$	MW	0,133	0,169
Combustion air	m_F*J_A	MW	2,509	3,962
Leakages	Q_{falsk}	MW	0,152	0,154
Total heat input	Q_{Ztot}	MW	248,333	263,614
Ash balance				
Slagge flow (incl. unburned)	m_{SL}	kg/s	3,0878	4,7380
Fly ash flow (incl. unburned)	m_{FA}	kg/s	4,6317	7,1070
Flow unburbed slag	$m_{SL} \cdot u_{SL}$	kg/s	0,0926	0,1817
Flow unburned fly ashe	$m_{FL} \cdot u_{FA}$	kg/s	0,0102	0,0426
Total ash with fuel	$m_{Bo}*\gamma_a$	kg/s	7,9892	12,1553
Ash balance (=0.0)		kg/s	0,0000	0,0000
Mass balance (fuel, air, flue gas og ash)				
Fuel	m_{Fo}	kg/s	18,9318	24,2137
Combustion air	m_L	kg/s	137,673	220,578
Total input	$m_{Bo}+m_{AS}+m_L$	kg/s	156,605	244,791
Flue gas	m_G	kg/s	148,885	232,946
Fly ash	m_{FA}	kg/s	4,632	7,107
Total output	$m_G+m_{SL}+m_{FA}$	kg/s	156,605	244,791
Mass balance (=0.0)		kg/s	0,0000	0,0000
Losses				
Flue gas loss (sensible heat)	Q_G	MW	15,295	23,538
Unburned CO loss	Q_{CO}	MW	0,000	0,000
Ash & slag losses:	Q_{SF}	MW	7,377	13,457
- sensible in fly ash	$m_{FA}*c_{FA}*(t_G-t_{ref})$	MW	0,382	0,571
- unburned in fly ash	$m_{FA}*u_{FA}*H_{uu}$	MW	0,336	1,407
- sensible in slag	$m_{SL}*c_{SL}*(t_{SL}-t_{ref})$	MW	3,628	5,567
Radiation- & convection losses:	Q_{RC}	MW	2,635	2,635
Fuel independent removed heat	Q_{ku}	MW	0,000	0,000
Total losses	Q_{Ltot}	MW	25,307	39,629
Specific losses				
Flue gas loss (sensible heat)	L_G	%	6,159	8,929
Unburned CO loss	L_{CO}	%	0,000	0,000
Ash & slag losses:	L_{SF}	%	2,971	5,105
- sensible in fly ash		%	0,154	0,217
- unburned in fly ash		%	0,135	0,534
- sensible in slag		%	1,461	2,112
- unburned in slag		%	1,231	2,275
Radiation- & convection losses:	L_{St}	%	1,061	0,999
Fuel efficiency (Q_N / Q_{Fo})		**%**	**90,831**	**86,371**
HHV	HHV	MJ/kg	13,816	11,580
Fuel efficiency HHV		**%**	**84,42%**	**78,72%**

1st Test

Ultimate fuel analysis at Raichur at 1st low load tests

CPRI Code	Clients Code	Carbon, %	Total Hydrogen, %	Nitrogen, %	Sulphur, %
MTDCATL23S0829	RTPS/U3/F0/05-03-2023/1	32.6	2.54	0.87	0.58
MTDCATL23S0830	RTPS/U3/F0/05-03-2023/2	38.4	3.11	0.76	0.50
MTDCATL23S0831	RTPS/U3/F0/05-03-2023/3	35.5	2.99	0.70	0.41
MTDCATL23S0832	RTPS/U3/F0/06-03-2023/1	35.6	2.96	0.92	0.66
MTDCATL23S0833	RTPS/U3/F0/06-03-2023/2	38.6	3.18	0.77	0.61

PF fuel samplings at Raichur at 1st low load tests

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
FLEXIBLE OPERATION OF KPCL

Sl no	DATE	DURATION	LOAD	UNIT	MILLS	WEIGHT OF EACH CORNOR			
						1	2	3	4
1	05.03.2023	9.25 TO 10.20	140	3	C	329	219.39	369.97	327.71
2	05.03.2023	9.25 TO 10.20		3	D	545.34	597.85	449.32	399.81
3	05.03.2023	9.25 TO 10.20		3	E	327.46	461.07	343.67	265.67
4	05.03.2023	9.25 TO 10.20		3	F	288.37	129.48	426.82	568.94
5	05.03.2023	11.55 TO 12.30	100	3	C	280.94	187.46	470.9	409.9
6	05.03.2023	11.55 TO 12.30		3	D	455.17	218.76	249.65	325.39
7	05.03.2023	11.55 TO 12.30		3	E	430.17	237.75	307.93	289.78
8	05.03.2023	2.20 TO 3.00	85	3	C	348.12	299.17	372.77	325.81
9	05.03.2023	2.20 TO 3.00		3	D	354.89	170.31	366.78	394.56
10	05.03.2023	2.20 TO 3.00		3	E	251.18	334.45	308.54	284.23

Sl no	DATE	DURATION	LOAD	UNIT	MILLS	WEIGHT OF EACH CORNOR			
						1	2	3	4
1	06.03.2023	9.30 TO 10.25	197 MW	3	A	217.15	235.69	237.12	373.05
2	06.03.2023	9.30 TO 10.25		3	B	381.02	273.94	274.88	439.65
3	06.03.2023	9.30 TO 10.25		3	C	245.52	464.66	549.39	402.24
4	06.03.2023	9.30 TO 10.25		3	D	511.96	207.85	303.19	330.99
5	06.03.2023	9.30 TO 10.25		3	E	246.63	641.41	352.16	366.51
5	06.03.2023	11.55 TO 12.30	85 MW	3	C	348.95	288.12	384.79	429.02
6	06.03.2023	11.55 TO 12.30		3	D	275.33	206.36	281.85	326.51
7	06.03.2023	11.55 TO 12.30		3	E	440.55	302.48	166.65	268.43

Sieve tests in 1st low load tests at Raichur

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
FLEXIBLE OPERATION OF UNIT-3
SIEVE ANALYSIS REPORT

SAMPLE:Pulversied coal sample of unit-3
SAMPLE ID-3
Date of sample collection:05.03.2023
Time of sample collection:2:20 to 3:00Hrs
Sample collection at load:85MW

MILL-C Sieve Analysis Size in microns (limits in %)						MILL-D Sieve Analysis Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)	CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	348.12	0.83	7.99	17.67	73.51	1	354.89	0.93	7.53	16.25	75.29
2	299.17	0.32	4.24	12.03	83.41	2	170.31	0.68	5.70	9.55	84.07
3	372.77	2.59	17.20	24.84	55.37	3	366.78	0.91	5.04	10.25	83.80
4	325.81	0.77	9.64	18.99	70.60	4	394.56	0.80	8.44	16.02	74.74

MILL-E Sieve Analysis Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	251.18	12.69	10.76	15.06	61.49
2	334.45	3.65	8.53	15.71	72.11
3	308.54	4.48	14.18	19.59	61.75
4	284.23	3.24	11.20	19.07	66.49

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
FLEXIBLE OPERATION OF UNIT-3
SIEVE ANALYSIS REPORT

SAMPLE:Pulversied coal sample of unit-3
SAMPLE ID-2
Date of sample collection:06.03.2023
Time of sample collection:11:55 TO 12:30Hrs
Sample collection at load:100MW

MILL-C Sieve Analysis Size in microns (limits in %)						MILL-D Sieve Analysis Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)	CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	348.95	0.63	10.14	21.89	67.34	1	275.33	0.53	4.37	11.56	83.54
2	288.12	1.65	9.67	17.70	70.98	2	206.36	0.61	5.87	11.64	81.88
3	384.79	1.94	16.96	21.57	59.53	3	281.85	0.47	3.82	10.65	85.06
4	429.02	0.68	8.55	18.99	71.78	4	326.51	1.07	8.37	16.94	73.62

MILL-E Sieve Analysis Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	440.55	8.44	11.26	18.38	61.92
2	302.48	7.84	14.27	19.85	58.04
3	166.65	1.74	8.92	14.69	74.65
4	268.43	3.03	11.97	16.54	68.46

2nd low load tests at Raichur

Ultimate fuel analysis

CPRI Code	Clients Code	Carbon, %	Total Hydrogen, %	Nitrogen, %	Sulphur, %
MTDCATL23S1269	RTPS/U3/FO/30-08-2023/1	35.6	2.96	0.92	0.55
MTDCATL23S1270	RTPS/U3/FO/30-08-2023/2	38.6	3.18	0.77	0.61

CPRI Code	Clients Code	Carbon, %	Total Hydrogen, %	Nitrogen, %	Sulphur, %
MTDCATL23S1252	RTPS/U3/FO/30-08-2023/3	28.4	3.15	0.59	0.55
MTDCATL23S1253	RTPS/U3/FO/30-08-2023/4	27.9	3.10	0.61	0.61
MTDCATL23S1254	RTPS/U3/FO/31-08-2023/1	30.1	3.27	0.65	1.12

PF fuel samplings

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
LOW LOAD TEST FOR FLEXIBLE OPERATION OF UNIT-3

Sl no	DATE	SAMPLE	TIME OF COLLECTION	SAMPLE COLLECTION AT LOAD	UNIT	MILLS	WEIGHT OF SAMPLE COLLECTED AT EACH CORNER FOR ONE MINTUE IN GRAMS			
							1	2	3	4
1	30.08.2023	PULVERIZED COAL SAMPLE OF UNIT-3	10:35 TO 11:05	163 MW	UNIT-3	B	449,11	330,53	259,35	345,43
2						C	544,24	390,75	625,79	661,56
3						D	590,51	353,36	357,62	341,35
4						E	606,64	536,52	367,44	346,98
5	30.08.2023		11:35 TO 12:15	120 MW	UNIT-3	B	386,43	254,41	204,89	277,37
6						C	351,03	661,6	623,29	381,36
7						D	228,74	200,7	229,43	232,1
8						E	358,76	355,32	245	200,08
9	30.08.2023		12:45 TO 13:13	109 MW	UNIT-3	C	654,38	401,04	575,44	561,09
10						D	375,59	438,01	374,75	261,48
11						E	409,1	373,95	481,18	269,75
12	30.08.2023		13:40 TO 14:10	73 MW	UNIT-3	C	475,34	577,71	809,11	423,71
13						D	172,79	155,26	192,36	242,29
14						E	249,12	378,01	290,25	209,64

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
LOW LOAD TEST FOR FLEXIBLE OPERATION OF UNIT-3

Sl no	DATE	SAMPLE	TIME OF COLLECTION	SAMPLE COLLECTION AT LOAD	UNIT	MILLS	WEIGHT OF SAMPLE COLLECTED AT EACH CORNER FOR ONE MINTUE IN GRAMS			
							1	2	3	4
1	31.08.2023	PULVERIZED COAL SAMPLE OF UNIT-3	11:35 TO 11:40	115MW	UNIT-3	F	141,5	223,4		
2	31.08.2023		12:35 TO 12:45	132MW	UNIT-3	A	159,83	135,34	133,86	201,97

Sieve tests in 2nd low load tests at Raichur

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
LOW LOAD TEST FOR FLEXIBLE OPERATION OF UNIT-3
SIEVE ANALYSIS REPORT

SAMPLE:Pulverized coal sample of unit-3
SAMPLE ID-1
Date of sample collection:30,08,2023
Time of sample collection:10:35 to 11:05
Sample collection at load:163MW

MILL-B — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	449,11	8,0	18,1	15,49	58,4
2	330,53	6,59	11,48	14,22	67,7
3	259,35	3,28	9,59	9,45	77,7
4	345,43	8,23	14,58	17,16	60,0

MILL-C — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	544,24	1,29	10,99	15,60	72,1
2	390,75	1,1	6,02	5,76	87,1
3	625,79	2,01	12,00	16,26	69,7
4	661,56	2,29	11,78	17,23	68,7

MILL-D — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	590,51	1,03	9,92	16,63	72,4
2	353,36	1,22	11,40	15,20	72,2
3	357,62	1,32	12,32	15,53	70,8
4	341,35	0,54	6,66	14,62	78,2

MILL-E — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	606,64	14,65	16,66	16,97	51,7
2	536,52	7,00	12,69	16,19	64,1
3	367,44	3,07	11,57	15,97	69,4
4	346,98	3,26	8,24	15,41	73,1

SAMPLE:Pulverized coal sample of unit-3
SAMPLE ID-2
Date of sample collection:30,08,2023
Time of sample collection:11:35 to 12:15
Sample collection at load:120MW

MILL-B — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	386,43	12,5	15,3	16,54	55,6
2	254,41	9,04	11,91	11,29	67,8
3	204,89	6,41	11,69	9,71	72,2
4	277,37	8,53	16,7	15,34	59,4

MILL-C — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	351,03	0,76	6,57	15,68	77,0
2	661,6	1,97	12,33	17,29	68,4
3	623,29	1,65	16,22	20,75	61,4
4	381,36	0,75	9,42	14,60	75,2

MILL-D — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	228,74	0,53	3,30	10,25	85,9
2	200,70	1,91	13,62	16,67	67,8
3	229,43	0,88	11,87	16,22	71,0
4	232,10	0,77	7,98	12,51	78,7

MILL-E — Sieve Analysis — Size in microns (limits in %)

CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	358,76	35,63	10,93	10,41	43,0
2	355,32	11,11	16,55	18,30	54,0
3	245,00	4,82	14,65	14,54	66,0
4	200,08	3,89	11,01	14,02	71,1

SAMPLE:Pulverized coal sample of unit-3
SAMPLE ID-3
Date of sample collection:30,08,2023
Time of sample collection:12:45 to 13:13
Sample collection at load:109MW

MILL-C						MILL-D					
Sieve Analysis						Sieve Analysis					
Size in microns (limits in %)						Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)	CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	654,38	1,01	9,87	18,41	70,7	1	375,59	0,83	6,50	12,92	79,8
2	401,04	0,66	3,77	4,44	91,1	2	438,01	1,82	14,64	17,10	66,4
3	575,44	2,86	14,86	17,81	64,5	3	374,75	0,81	11,86	15,56	71,8
4	561,09	2,59	13,01	13,89	70,5	4	261,48	0,7	6,02	13,55	79,7

MILL-E					
Sieve Analysis					
Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	409,1	18,94	14,61	14,19	52,3
2	373,95	6,03	12,44	10,35	71,2
3	481,18	4,83	13,76	15,42	66,0
4	269,75	4,77	9,16	12,49	73,6

SAMPLE:Pulverized coal sample of unit-3
SAMPLE ID-4
Date of sample collection:30,08,2023
Time of sample collection:13:40 to14:10
Sample collection at load:73MW

MILL-C						MILL-D					
Sieve Analysis						Sieve Analysis					
Size in microns (limits in %)						Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)	CORNER	Quantity of Sample collected in one minute (in grams)	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	475,34	0,92	7,90	15,12	76,1	1	172,79	0,76	2,42	7,74	89,1
2	577,71	1,1	7,46	12,51	78,9	2	155,26	0,4	3,65	6,16	89,8
3	809,11	1,65	17,11	24,05	57,2	3	192,36	0,43	3,33	10,30	85,9
4	423,71	1,59	13,25	21,3	63,9	4	242,29	0,76	6,77	16,09	76,4

MILL-E					
Sieve Analysis					
Size in microns (limits in %)					
CORNER	Quantity of Sample collected in one minute (in	300 (<5%)	150 (<10%)	75 (<15%)	-75 (>70%)
1	249,12	32,94	11,63	9,16	46,3
2	378,01	8,68	15,05	21,19	55,1
3	290,25	4,72	13,07	18,07	64,1
4	209,64	3,93	8,62	15,66	71,8

Unburnt Carbon (UBC)

The test data from the Plant's laboratory:

Bottom ash and Fly ash analysis Report		
Date		05.03.2023
Units	% of unburnt Combustibles in Bottom Ash	% of unburnt Combustibles in Fly Ash
3	3.01	0.22

Bottom ash and Fly ash analysis Report		
Date		06.03.2023
Units	% of unburnt Combustibles in Bottom Ash	% of unburnt Combustibles in Fly Ash
3	1.72	0.6

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
BOTTOM ASH AND FLY ASH ANALYSIS REPORT
LOW LOAD TEST FOR FLEXIBLE OPERATION OF UNIT-3

SL NO	Date	UNIT	TIME OF COLLECTION OF BOTTOM ASH	% of unburnt Combustibles in Bottom Ash	TIME OF COLLECTION OF FLY ASH	% of unburnt Combustibles in Fly Ash
1	30.08.2023	Unit-3	11:33	2,88	11:54	0,64
2	30.08.2023	Unit-3	16:09	4,79	16:52	0,56

KARNATAKA POWER CORPORATION LIMITED
RAICHUR THERMAL POWER STATION
BOTTOM ASH AND FLY ASH ANALYSIS REPORT
LOW LOAD TEST FOR FLEXIBLE OPERATION OF UNIT-3

SL NO	Date	UNIT	TIME OF COLLECTION OF BOTTOM ASH	% of unburnt Combustibles in Bottom Ash	TIME OF COLLECTION OF FLY ASH	% of unburnt Combustibles in Fly Ash
1	31.08.2023	Unit-3	07:30	1,60	11,00	0,31
2	31.08.2023	Unit-3	16:00	3,33	16:15	0,21