2018-2019 Final Report

Flexibilisation Study at Vindhyachal Super Thermal Power Station (VSTPS)

2019 July

New Energy and Industrial Technology Development Organization

Subcontractor: JERA Co., Inc

Mitsubishi Research Institute, Inc.

Summary

In India, the rapid expansion of renewable capacity requires existing coal-fired power plants to improve flexibility of operation to meet the fluctuations of electricity demand. Indian government has requested Japan to explore feasible study to improve thermal power plant operation in India.

The purpose of this study is to improve operational flexibility of one of the Indian coal-fired power units and optimize operation of one group of power units by using a real-time monitoring system. The study is expected to be used as a foundation stone for further deployment of the measure to other existing power plants throughout India. By doing so the program aims to contribute to CO2 emission reductions.

In the first chapter, Indian energy policies, environmental policies, and energy saving policies are addressed. Then, focusing on the flexibility of operation of various power sources including storage batteries are examined and described.

In the second chapter, concerning specific thermal power unit, we evaluated design data, operational records, results of ramp up/down test and interviews with operators. We made recommendations to improve flexibility of operation of specific unit by (1) lowering minimum load, (2) shortening startup time, (3) increasing ramp rate. When flexibility of operation will be improved, it is anticipated that occasion of partial load operation will increase, therefore we also proposed (4) improving partial load efficiency. In addition, we indicated the possibility of saving 140,000 (ton/year) of coal if our proposed optimize operation method were applied for specified 6 units of coal-fired power plant in the year of 2018, and also we indicated the potential of saving 100,000(ton/year) of coal with our proposed optimize operation method for the same specified 6 units under the scenario of big renewable capacity introduction in the year of 2022.

This study shows that real time monitoring service is useful. We demonstrated in the third chapter that it is economically feasible to provide services with IoT based systems owned by JERA to India. The progress of the Indian government's target of additional renewable capacity (175GW) is also important for further deployment of this system.

In the fourth chapter, we elaborate on a risk management plan by international risk management demonstration guidelines.

In the fifth chapter, our study shows that there has been discussion within the Ministry to consider an ancillary service market, which also suggests that sending operational data to Japan from Indian sites can be legally acceptable. We also identified that there are high demands across India for coal fired generation plant output change response technology.

In the sixth chapter, a roadmap for Japan-India energy dialogue as well as a necessity to promote the programme is discussed. We examined how to achieve the Indian government's various targets of climate change policy and energy efficiency, and how to contribute to India's current and future rapid expansion of renewable energy by improving the flexibility of existing coal generation. Technical solutions for Japan-India energy policy dialogue are also summarized in this chapter.

In the final chapter, we identify the quantification measure to calculate realized GHG emission reductions through our thermal efficiency improvement method. As a result, a 500MW unit can reduce GHG by up to 318,000 t-CO2 per annum, and an entire power plant can reduce GHG by 14,5000 t-CO2 per annum through optimization.

For your reference, second chapter and final chapter are extracted in next pages.

Chapter 2 Eligibility of proposed technology and system

2.1 Thermal Power Station for study

We selected NTPC’s Vindhyachal Super Thermal Power Station (VSTPS) for study, based on the recommendation of Ministry of Power and Central Electricity Authority. We have investigated concerning improvement of operational flexibility of No.11 unit and optimal operation of 6 units of stage I which means No.1 to No.6 unit.

Figure 2-1 Location of VSTPS

Table 2-1 Units of VSTPS

Stage	Unit number	capacity (MW)	Operation start date
I	1	210	October 1987
	2	210	July 1988
	3	210	February 1989
	4	210	December 1989
	5	210	March 1990
	6	210	February 1991
II	7	500	March 1999
	8	500	February 2007

III	9	500	July 2006
	10	500	March 2007
IV	11	500	June 2014
	12	500	April 2013
V	13	500	August 2015
Total	13	4,760	-

2.2 Investigation and analysis

Figure 2-2 Whole view of Vindhyachal STPS

Figure 2-3 Wrap up meeting

Table 2-2 Schedule of site survey

	4^{th}March2019	5^{th}March2019	6^{th}March2019	7^{th}March2019	8^{th}March2019
Kick off meeting					
Field confirmation					
Confirmation of unaccepted data					
interview					
Ramp Down/Up test Minimum load test			Pre-meeting		
Wrap up meeting					

2.2.1 Objective

To propose useful countermeasures for improving flexibility of operation of Vindhyachal No.11 unit, we collected design data and past operational records, we interviewed engineers about their way of operation. And on 6th -7th March 2019, thanks for NTPC, we had a chance to observe ‘ Ramp Down/Up ’ test which was implemented by our request. We could understand actual ability of operation of Vindhyachal No.11unit.
We understand improvement of flexibility of operation means ‘Lower Minimum Load’, ’Shorten Startup Time’ and ‘Increase Ramp Rate’. We will make a proposal to improve such kind of abilities of operation of Vindhyachal No.11uint.
And when flexibility of operation will be improved, we estimate occasion of partial load operation will increase. Therefore, we will propose useful countermeasures to increase thermal efficiency during partial load operation and we will try to calculate the amount of increase of thermal efficiency in case our proposal will be adopted.

2.2.2 Investigation

(1) Data collection, document search

1) results of investigation

We requested data regarding investigation on ‘Lower Minimum Load’, ’Shorten Startup Time’, ‘Increase Ramp Rate’ and ‘Increase partial load thermal efficiency’ to NTPC. Thanks for NTPC we obtained enough data for our study.

2) special notes

Before starting this study, we supposed ‘ Steam pressure reduction operation during partial load’ and ‘ Boiler-turbine coordination control’ were candidates of methods of improving operational flexibility of No.11 unit of VSTPS. However, after our site investigation, we understand these 2 methods were already implemented at No.11 unit of VSTPS.

(2) Ramp Down / Up test

On 6th -7th March 2019, thanks for NTPC, we had a chance to observe Ramp Down / Up test which was implemented by our request. Results are as follows.

1) Ramp Down / Up test at actual ramp rate (1.5%/min) on 6th March 2019

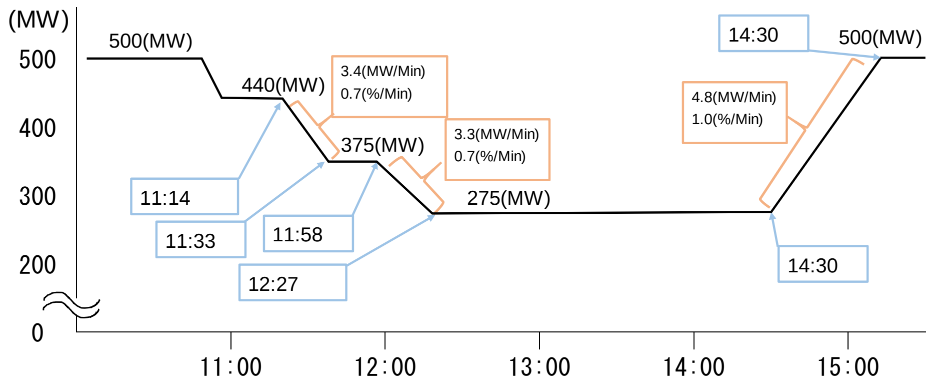


Figure 2-4 Results of test on 6th March 2019

- We set ramp rate 1.5%/min, however actual ramp rate of the test was 0.7- 1.0%/min.
- When load come down from 500MW to 275MW, load was held at 440MW to stop 1 mill.
- During the operation of 275MW, number of operating mills were 5. Top mill was operated with partial load.
- Fluctuation of drum level was very big.
- During ramp up, deviation of steam temperature was big.
- Combustion monitoring camera was not installed. However, we understood combustion situation in the furnace of boiler was good by observing through peep hole.
- The density of CO was not measured continuously because CO analyzer was removed. We observed the result of measurement of CO, 3 ppm, at the entrance of stack by portable analyzer. And we evaluated condition of combustion was good.

2) Ramp Down / Up test at high ramp rate (3.0%/min) on 7th March 2019

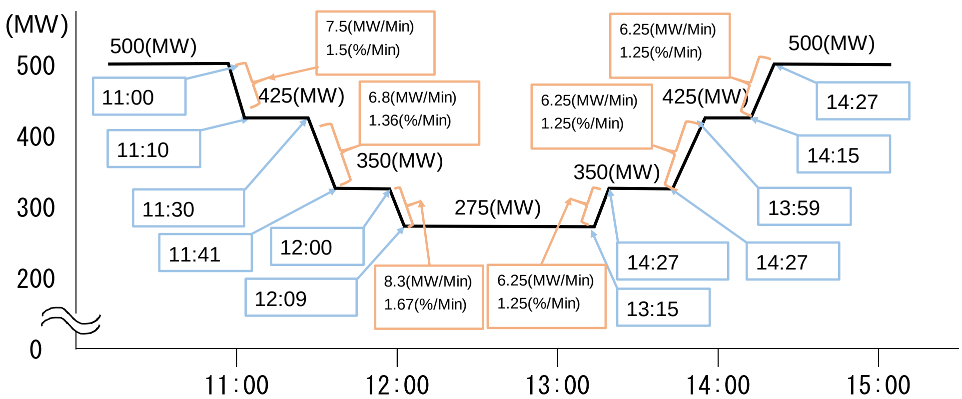


Figure 2-5 Results of test on 7th March 2019

- In spite of setting ramp rate 3%/min, unit No.11 could change its output with 1.25 - 1.5%/min.
- During ramp down test from 500MW to 425MW, output was once reduced to 412MW and in 10 minutes output recovered to 425MW. Tuning of Control logic seemed not enough.
- Re-heater temperature did not reach to design temperature.
- Number of mills operated at 500MW was 6 at 6th March 2019, but 7 at 7th March 2019. During the operation of 275MW, one of mill was controlled manually at 6th March 2019, but all mills were controlled automatically at 7th March 2019.

(3) Interview to operator

We interviewed to operators concerning actual situation of operation from 4th to 8th March 2019.

1) Minimum load

- Number of mills of actual minimum load operation at 275MW was 4.
- Operators understood further reduction of minimum load was impossible because combustion situation of boiler got worse.
- One of the factor which makes combustion worse is fluctuation of coal calorific value. At the operation of 500MW, when calorific value was high, amount of coal consumption was 250 ton/hour, but when calorific value was low, amount of coal consumption was 400 ton/hour.
- Based on the design documents, regardless of output, O_2 density is controlled at 3.58%. However, in reality, O_2 density increases with the decrease of output.
- When low calorific value coal is consumed, 2nd air is increased 5% to stabilize combustion.
- No.11 unit has an experience of trip due to the loss of all flame during minimum load operation.
- At this moment, no special actions are taken to improve combustion situation.
- Employees of NTPC at Vindhyachal seemed not to have strong motivation to reduce minimum load. They said auxiliary power ratio is increased with the decrease of output.
- 2 BFPs are operated at 275MW.

2) Start up time

- Ignition of boiler is operated manually. Procedure after turbine start are implemented automatically.
- Drain valves are also manually manipulated during start up from central controlled room.
- All the manipulation of start-up is implemented from central controlled room, and there is no on-site operation.

- Procedure of start-up operation is written in manual and standardized. Young operator operates under the surveillance of veteran operator.
- There is no repeated problem during starting up.

3) Load dispatch control

- 2 unit of No.11 and No.12 are regarded StageIV.
- 24 hours are divided into 15 minutes 96 blocks, dispatching center orders to generate electricity for 2 units of StageIV for each 1 block by the signal called SG (Scheduled Generation).
- At the central control room of Vindhyachal No.11 unit and No.12 unit, operator recognizes target load of 2 units of StageIV by the SG sent by dispatching center. Operator decides load of each unit and controls load of each unit. The amount of SG is prepared one day before and decided 1 hour before.
- (reference) In Japan, Automatic Dispatch Control system (ADC) which consists of Load Frequency Control System (LFC) and Economic Load Dispatch Control System (EDC) are equipped between central control room and each unit. Each unit is controlled automatically by central dispatching center within the load band which is determined by the individual operational constraints.

4) Partial load operation

- During partial load operation, boiler pressure is reduced.
- Actual minimum load is 275MW, therefore it is difficult to reduce the number of BFPs.

(4) Results of investigation

1) Ability of operation on design basis

Based on design data, minimum load is 30-40% MCR (Maximum Continuous Rating), hot start mode startup time from boiler igniting to maximum load is 80 minutes, ramp rate is 2.6% which is calculated from the design hot start curve. These specifications are almost same as the specifications of our coal thermal power plant. And we understand No.11 unit has enough ability of operation on design basis.

Table 2-3 Flexibility of Vindhyachal No.11 unit and No. A unit of Japan

	Vindhyachal No.11		No.A unit (Domestic plant)
	design	actual	actual
Minimum Load Rate	30% - 40%	55%	30%
Ramp Up/Down Rate	2.6%	1.5%	3%
Startup Time* (after 8 hours stop)	80 min	227 min	300 min
Startup Time* (after 36 hours stop)	164 min	–	416 min
Startup Time* (cold start)	400 min	–	707 min

2) Actual operational ability

Based on the records of ramp down/up test on 6th and 7th March 2019, minimum load is 55% MCR which is larger than design minimum load, ramp rate is around 1.5% at most which is smaller than design ramp rate. Actual operational ability of Vindhyachal No.11 unit is much more inferior to design base operational ability.

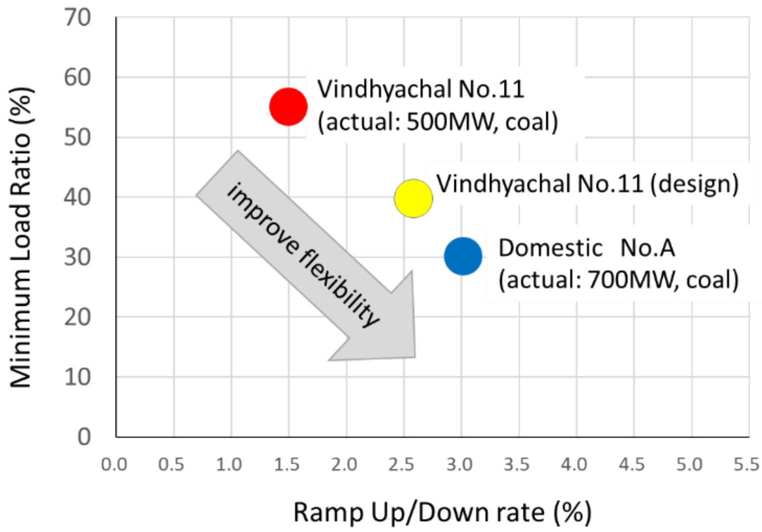


Figure 2-6 Ramp Down/Up rate & Minimum Load Ratio

a. load overshoot

As for No.11 unit, in spite of operating with lower ramp rate, overshoot of load is observed.

To decrease the loss of throttle valve, Vindhyachal No.11 unit decreases steam pressure when load goes down. As for drum type boiler, steam pressure is controlled by fuel flow (amount of fuel inputted to boiler). When steam pressure actual value is higher than setting value, control logic generates signal of reducing fuel flow, and after a while, steam pressure will recover. When dispatch center decreases output of power plant, control logic reduces fuel flow and closes control valve of steam turbine. In this timing, when control valve of steam turbine closes, steam pressure increases then control logic reduces fuel flow further. In addition to this, because of variable pressure operation, steam pressure setting value goes down when output goes down, then deviation between steam pressure setting value and real steam pressure spreads. For this reason, control logic again reduces fuel flow. In this way, when output decreases, control logic generate signal of decreasing fuel flow 3 times. And real fuel flow decreases too much. By these reasons, we assume that fuel flow overshoots.

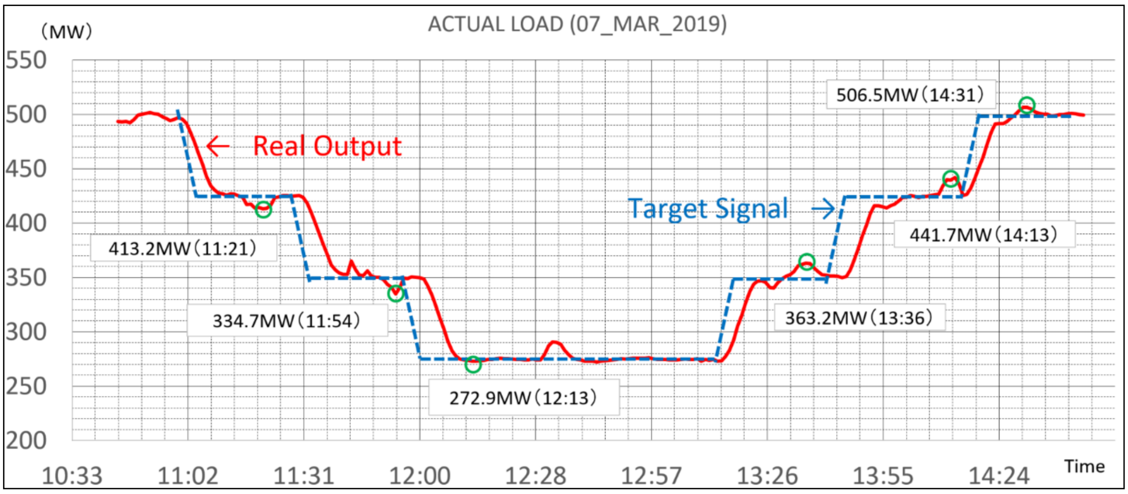


Figure 2-7 Ramp Down / Up test dated 7th March 2019

b. load hold during mill service-in / service-out

As for No.11 unit, during ramp down and ramp up, when mill stops operation or starts operation, operator stops load change. It seems that this kind of operation is adopted because of bad control of coal flow.

When mill starts operation, it takes minutes from coal injection to mill, up to pulverized coal injection to burner. Coal flow used for plant control is measured at coal feeder, therefore there exists some time difference between measured coal flow and real pulverized coal flow to burner. And this difference has harmful influence on plant control.

It is impossible to improve ramp rate without improving actual load holding operation during mill stops and starts.

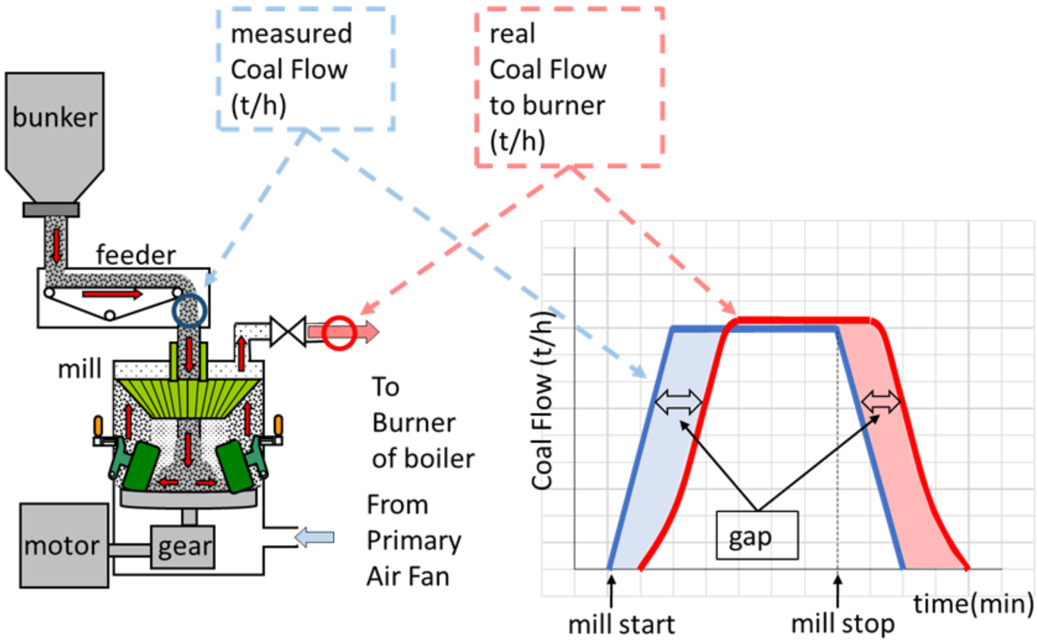


Figure 2-8 Gap between 'measured Coal Flow' and 'real Coal Flow to Burner'

c. Calorific Value (CV) correction

CV correction logic is installed to No.11 unit, however, the value of CV correction is almost unchanged and it seems not renewed properly. Therefore when No.11 unit uses coal with CV largely deviated from standard coal, real heat value input to boiler is not recognized properly by plant control system and load control becomes difficult.

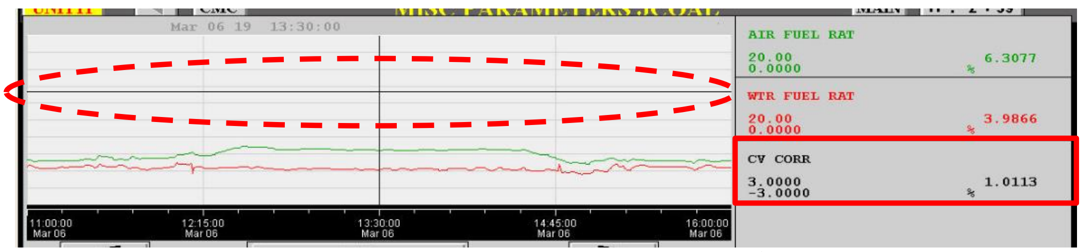


Figure 2-9 Trend of CV correction 11:00 – 16:00, 6th March 2019

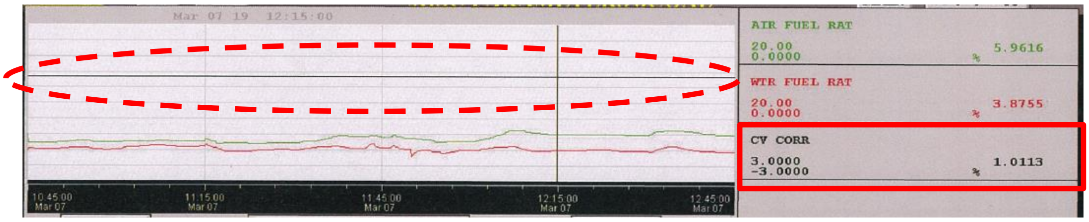


Figure 2-10 Trend of CV correction 10:45 – 12:45, 7th March 2019

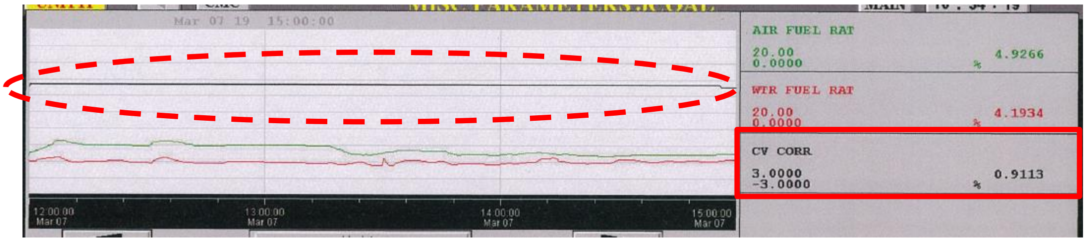


Figure 2-11 Trend of CV correction 12:00 – 15:00, 7th March 2019

d. fluctuation of drum level

Fluctuation of drum level is big at various load. And fluctuation of drum is occurred during ramping or at lower load.

Table 2-4 fluctuation of drum level

Maximum fluctuation range (positive side)	Maximum fluctuation range (minus side)
68.26cm（at 417MW）	-44.44cm（at 434MW）

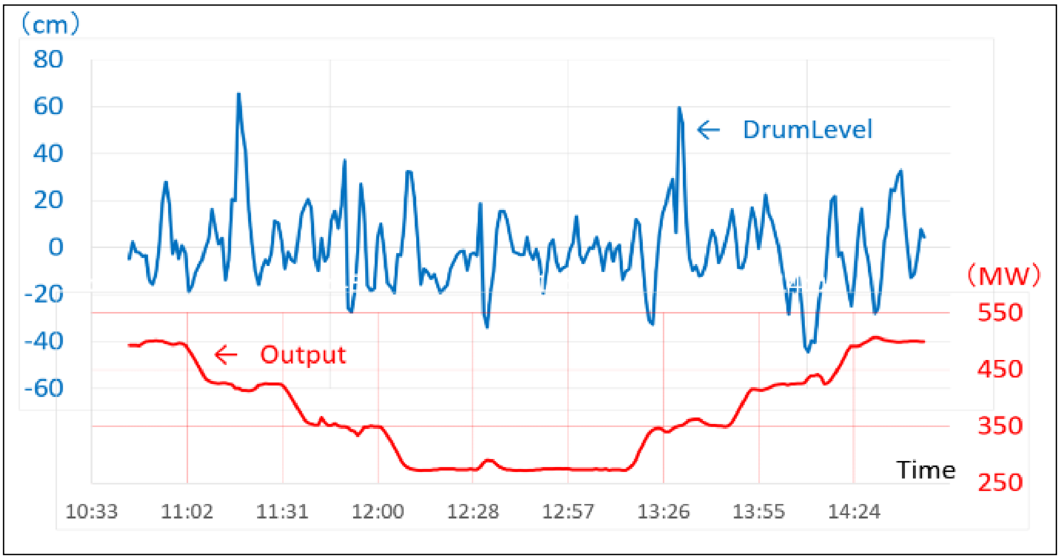


Figure 2-12 Drum level fluctuation during ramp down / up test 7th March 2019

We assumed that reduction of steam pressure affects drum level control. Drum level is controlled by the amount of feed water. When steam pressure goes down with load fall, it becomes easy for water to get into drum and fluctuation of drum level becomes larger.

e. insufficient tuning of control logic

To use control logic properly, tuning is very important. But as for No.11 unit, tuning at static condition and dynamic condition seems not be done well during trial operation. Static condition data of control logic should match with characteristics of unit.

3) Performance deteriorated equipment

We made Heat-Balance diagram. Heat-Balance diagram indicates transfer of heat from combustion of fuel to generation of electricity. This can calculate heat rate of total unit and this can evaluate efficiency of each equipment which composes unit.

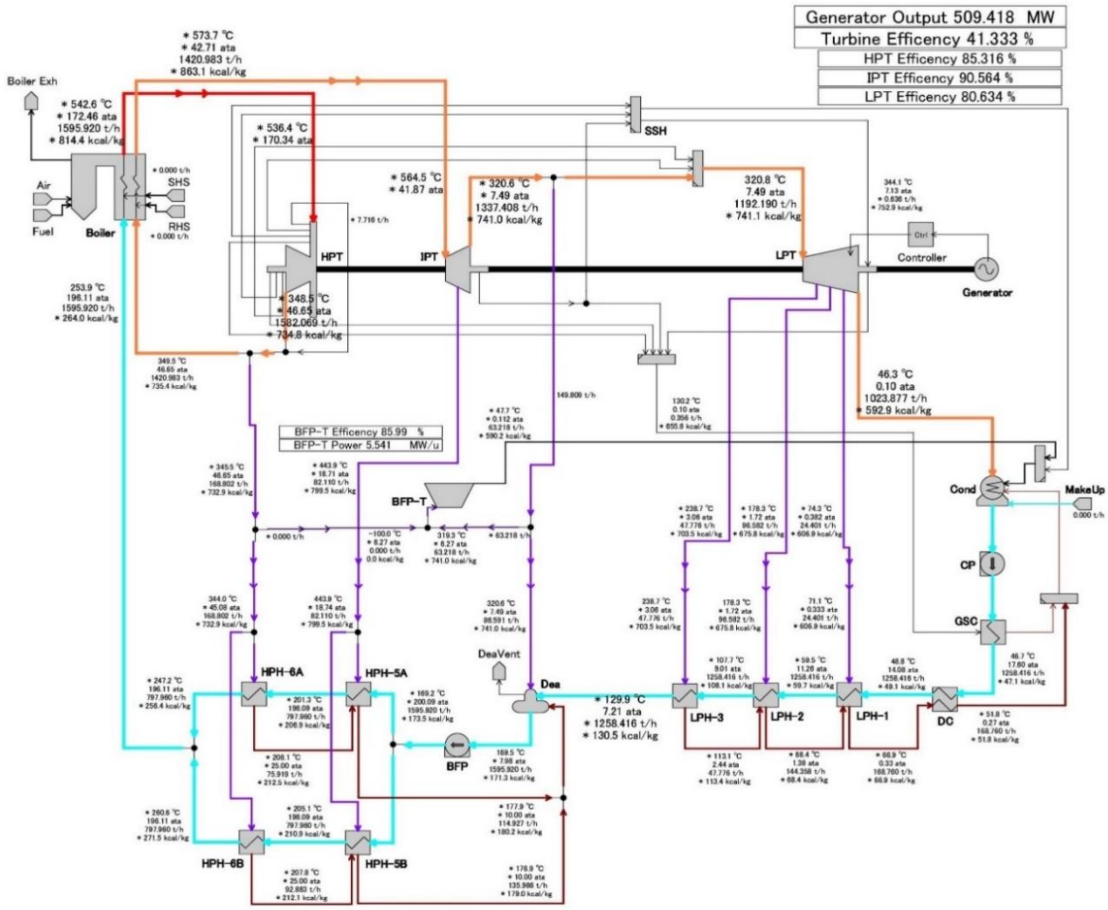


Figure 2-13 Heat-Balance diagram of 500MW, 5th January 2018

We observed around 5(%) decline of performance of HP turbine in 3 years. As for IP turbine, there is no big decline of performance.

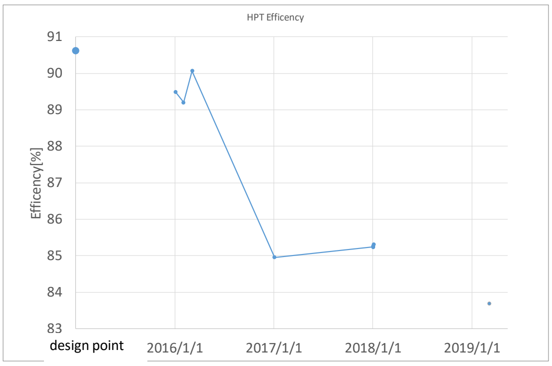


Figure 2-14 Adiabatic efficiency of HP turbine

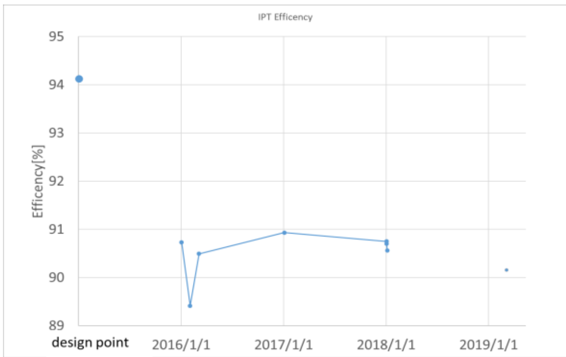


Figure 2-15 Adiabatic efficiency of IP turbine

4) Fluctuation of Calorific Value (CV) of coal

During our site survey, we heard it is difficult to decrease minimum load because of big CV fluctuation. Then we compared coal CV of 90 days of Vindhyachl with No.A unit of Japan, and found out that fluctuation of coal CV of Vindhyachal is bigger than No.A unit of Japan.

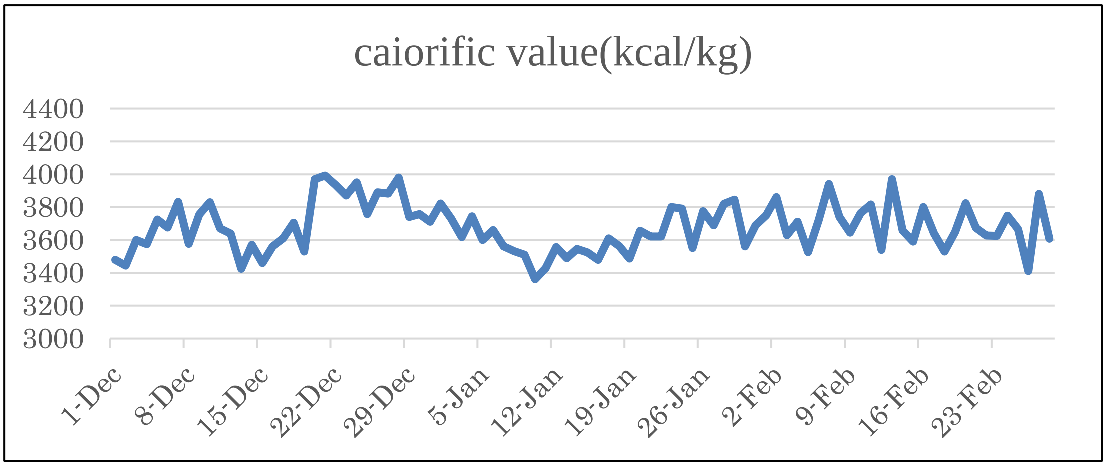


Figure 2-16 fluctuation of coal CV of Vindhyachal

5) Frequency control

Indian 5 regional electrical networks (NR, WR, SR, ER, NER) used to operate separately, but from 1991 these networks were interconnected step by step and all regional networks had interconnected and become one national grid 31st December 2013.

At the beginning of interconnection, frequency control was not so good, and fluctuation of frequency was big. But fluctuation becomes smaller with the implementation of countermeasures such as Deviation Settlement Mechanism (DSM) and Reserves Regulation Ancillary Services (RRAS). Target frequency band decided by Indian Electricity Grid Code also becomes smaller.

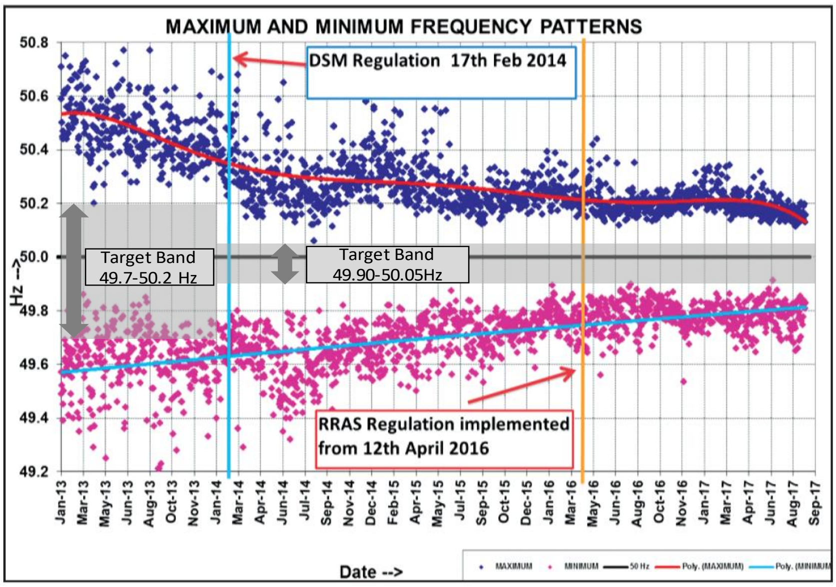


Figure 2-17 Trend of Maximum / Minimum Frequency and target frequency band

However, when we compare actual frequency fluctuation of India and Japan, we find big difference. The cause of this is due to the difference of frequency control method,

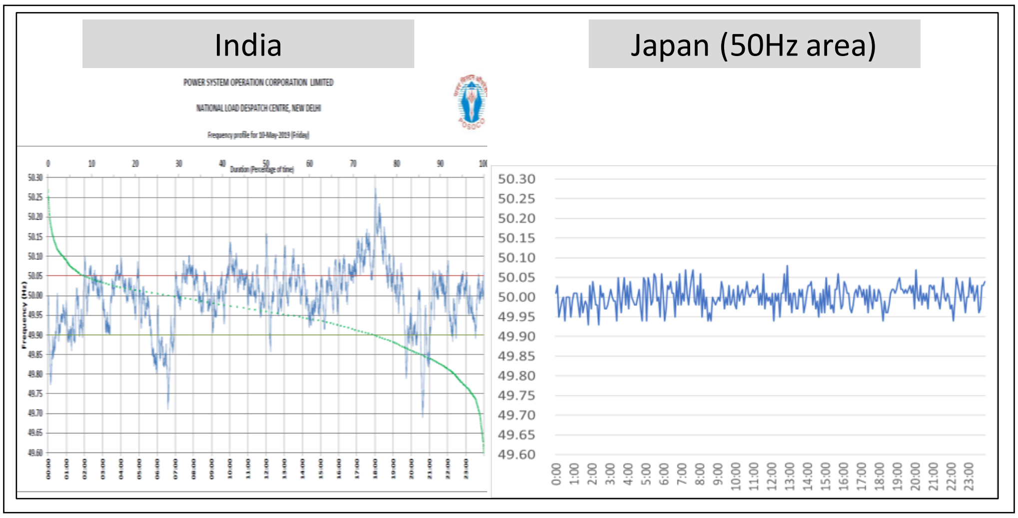


Figure 2-18 Frequency of India and Japan dated 10th May 2019

Load of power plants in India are controlled by RGMO (Restricted Governor Mode of Operation) which can keep frequency a little bit higher than 50Hz, and RRAS (Reserves Regulation Ancillary Service).

RGMO is an independent automatic frequency quick control system, however RGMO uses accumulated heat of boiler, therefore once accumulated heat exhausted, RGMO is no longer functional. RGMO can only absorb small fluctuation of frequency.

And as for RRAS, by which Vindhyachal receives dispatch order every 15 minutes from dispatch center, dispatch center can't change actual dispatch order. At least 45 minutes are required to change dispatch order.

By these kinds of frequency control methods, it is difficult to keep frequency in setting band in case of big fluctuation of frequency, which happens when demand of electricity rises quickly, output of solar power rises quickly, other power plant stops suddenly by accident. If India continues to use these kinds of frequency control devices, it is also difficult to use thermal power plant effectively, even if thermal power plant improves its ability of flexible operation.

2.2.3 Proposal

(1) Improvement and addition of control logic

We investigated the ability of control logic of No.11 unit by ramp down/up test, and we found out the problem as follows.

- We observed many behaviors of overshoot of load of generator during ramp down/up test.
- We observed load was held during mill service-in / service-out. It seems that this kind of operation is adopted because of bad control of coal flow.
- Calorific Value correction logic is installed to No.11 unit, however, the value of CV correction is almost same and it seems not renewed properly.
- Fluctuation of drum level is big at various load. And fluctuation of drum is occurred during ramping or at lower load.
- Tuning of control logic seems not enough.

Based on the result of ramp down/up test, and investigation regarding actual control logic, we understand control logic of No.11 unit does not fit for 'High Ramp Rate Operation' and 'Boiler

Pressure Reducing Operation'. Therefore, improvement and addition of control logic is required. On design basis, No.11 unit has enough flexibility of operation, but as a matter of fact, lack of some control logics and lack of enough tuning at test operation, actual flexibility of operation is limited.

We assume that if proposed improvement and addition of control logic is implemented, and tuned, we will be able to make ramp rate higher and we will be able to make minimum load lower.

As for minimum load reduction, based on the design documents, minimum load is said to be 30 – 40%MCR. Thermal power unit is basically designed to be operated at rated output, therefore as the output becomes low, combustion situation becomes worse and control becomes unstable. As No.11 unit has very little experience to be operated under 275MW, at first, we recommend to achieve 250MW operation by combustion adjustment and tuning of control system. At 250MW operation, number of operating BFPs could be reduced to one, and this contributes to increase thermal efficiency. And as for further reduction of minimum load, detailed investigations should be done by the operational data of 250MW.

1) Improvement of control logic of main steam pressure

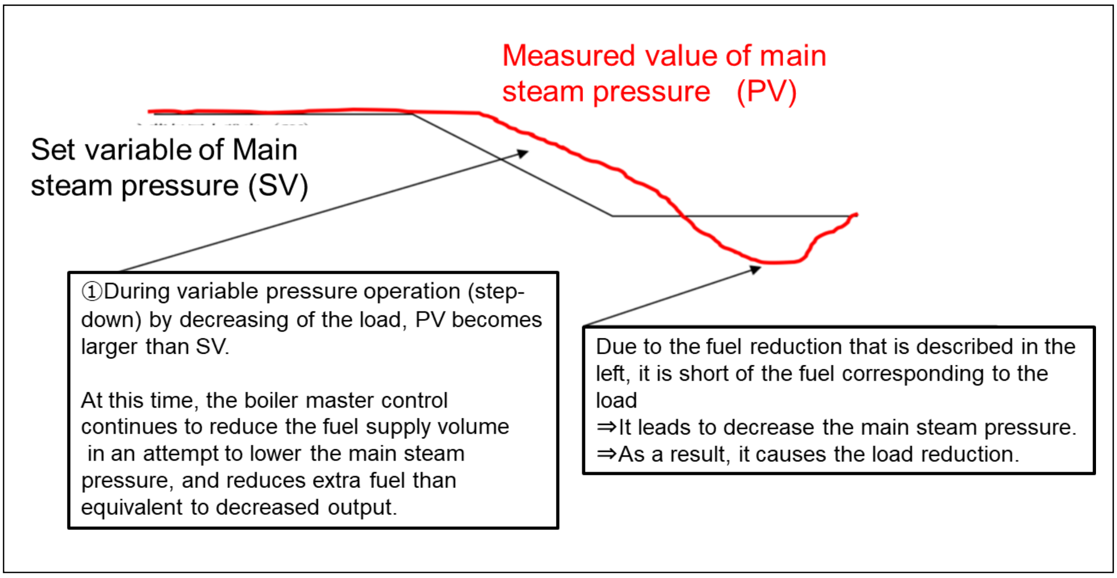


Figure 2-19 One example of overshoot

Overshoot due to ramping occurs by the action of control logic which correct deviation of steam pressure. We found integral action of load control logic during ramping is a cause of overshooting. Therefore, we recommend to restrict the function of integral action and adjust proportional action of load control logic.

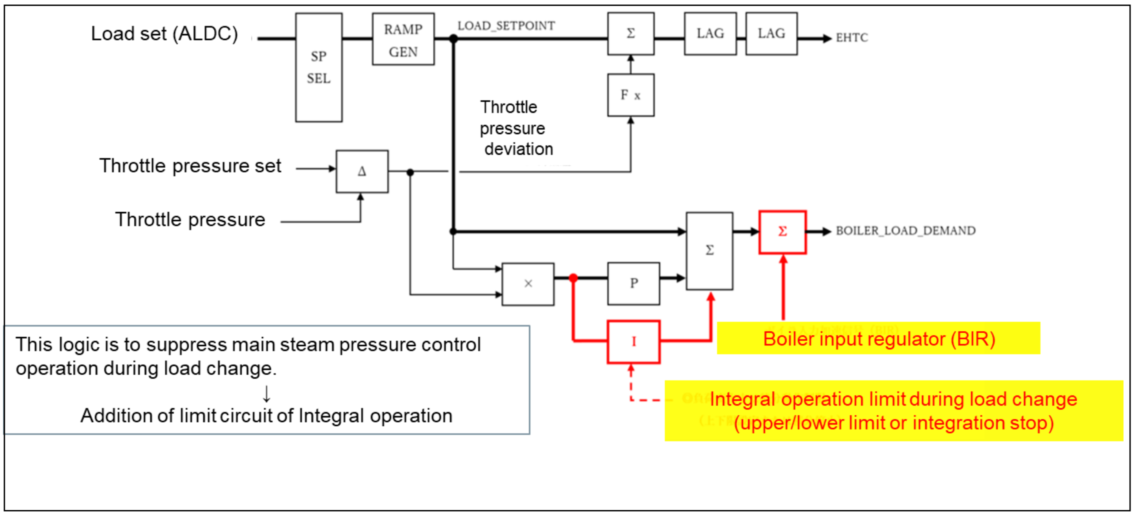


Figure 2-20 load control logic

We also recommend to add Boiler Input Regulator (BIR) into load control logic to reduce overshoot.

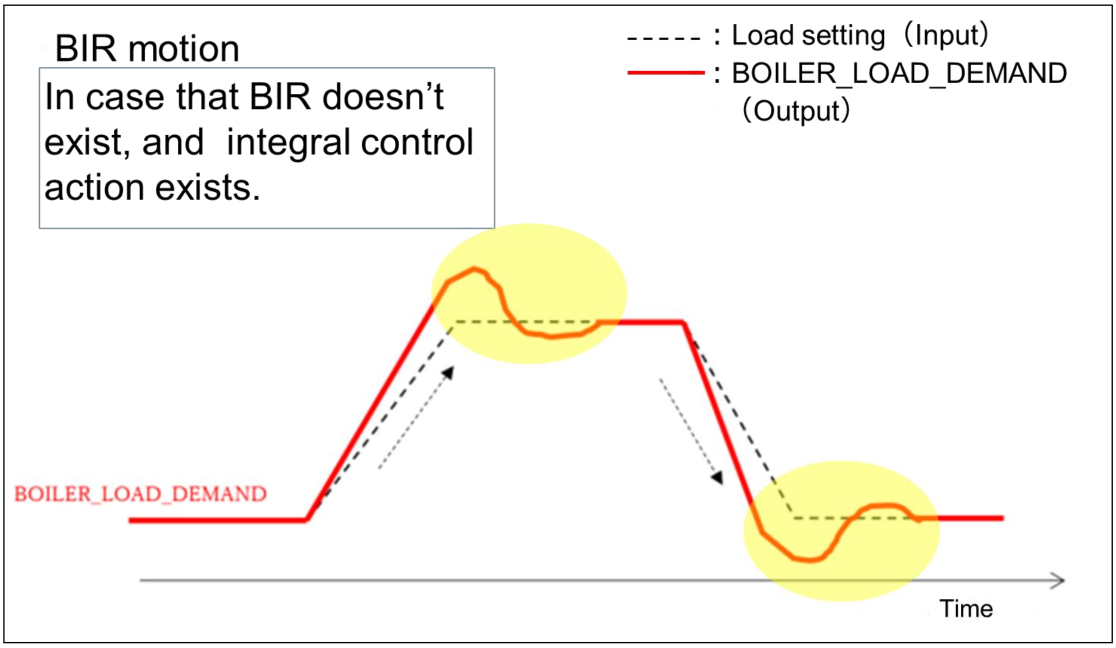


Figure 2-21 Actual signal of Boiler Load Demand

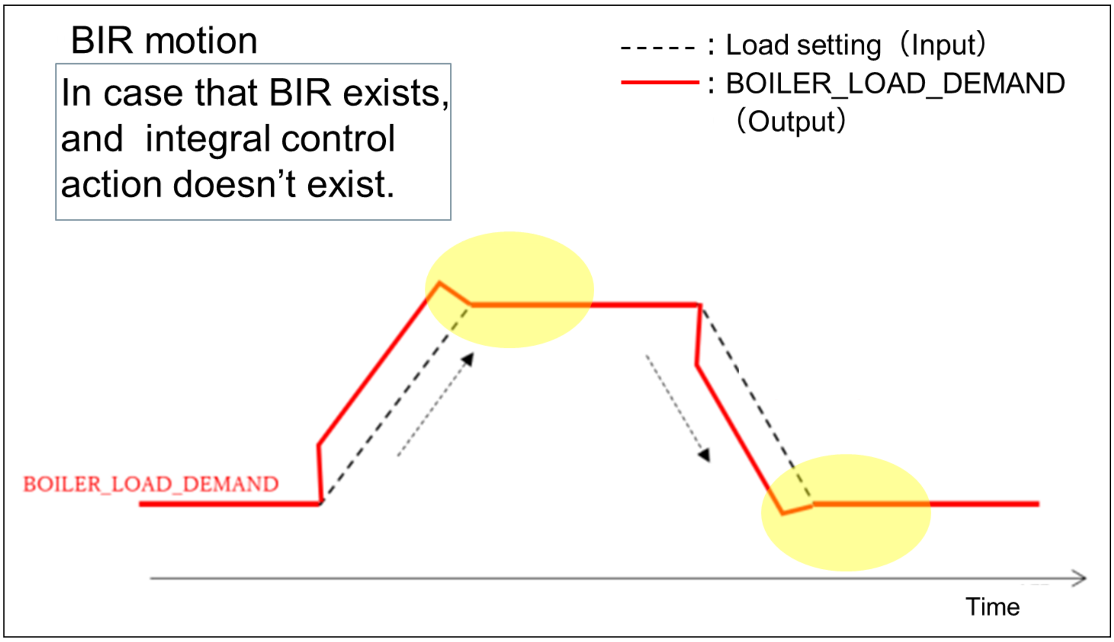


Figure 2-22 Signal of Boiler Load Demand after introducing Boiler Input Regulator (BIR)

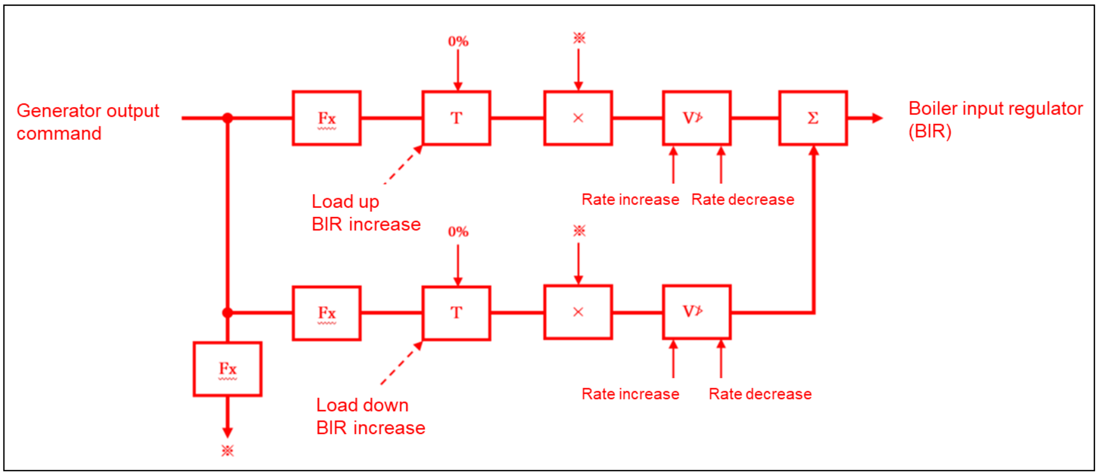


Figure 2-23 one example of control logic of Boiler Input Regulator (BIR)

2) Improvement of drum level control

No.11 unit adopts variable pressure operation, so that when output of generator decreases, steam pressure also decreases. And when steam pressure decreases, it is easy for feed water to get into drum, and fluctuation of drum level becomes larger. We recommend to make drum level control insensitive depends on the steam pressure. The lower the steam pressure, we recommend to make level control more insensitive.

Method to make level control insensitive is to multiply signal of deviation of drum level by variable gain circuit.

If 250MW operation will be achieved, number of operating BFPs could be reduced to one. In this case, it is difficult for feed water to get into drum. We recommend to make level control more sensitive when number of operating BFP reduces.

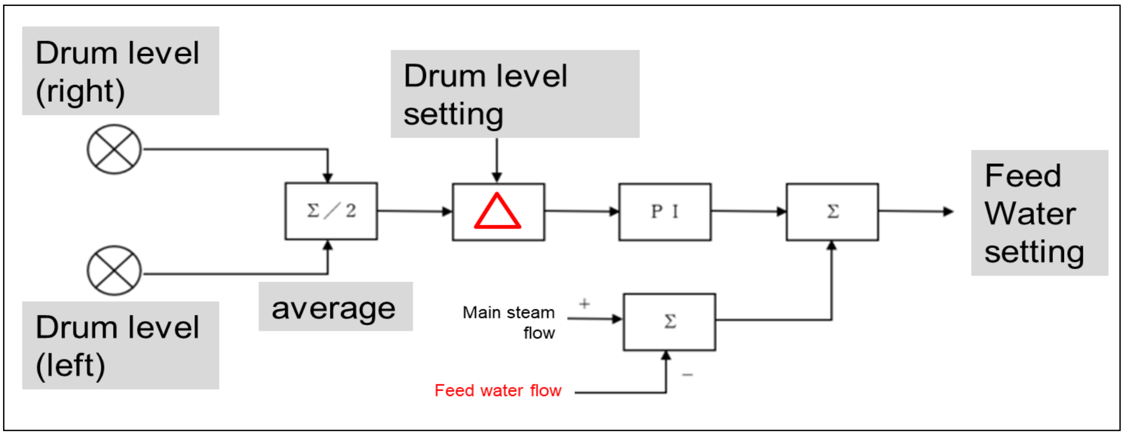


Figure 2-24 Control logic of drum level (actual)

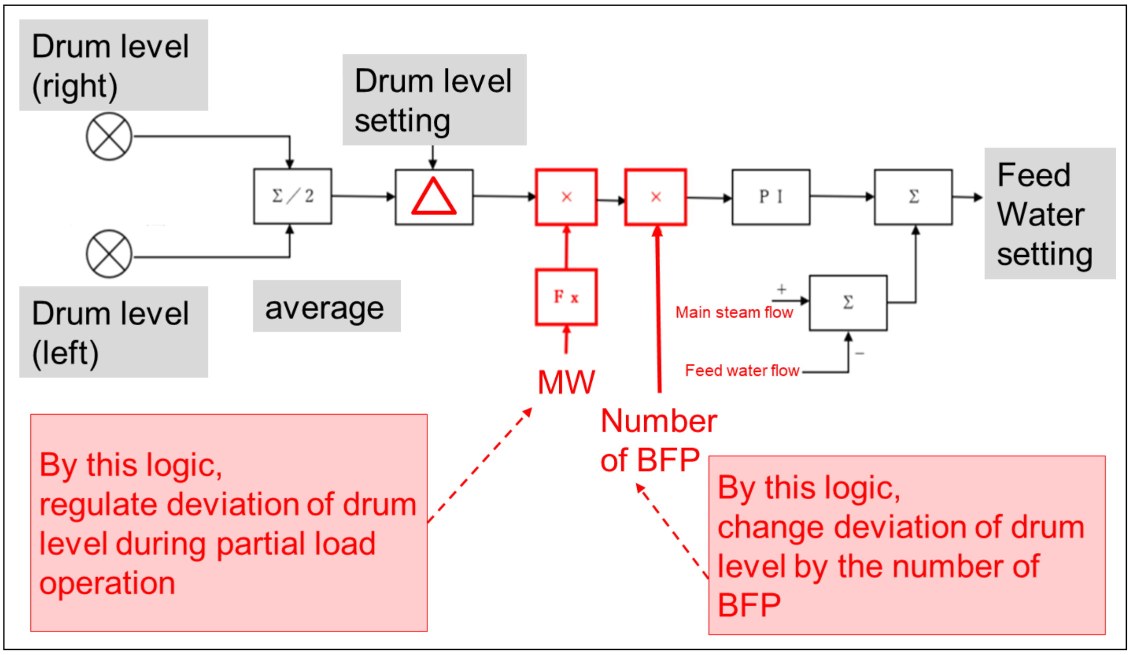


Figure 2-25 Control logic of drum level (proposed)

3) Improvement of ‘Calorific Value(CV) Correction Logic’

We understand fluctuation of CV is big. Concerning control of drum type boiler, fuel flow (ton/hour) is a very important parameter which determine output (MW) or amount of evaporation of boiler (ton/hour). Output(MW) is decided by the amount of heat injection to boiler, here heat injection means ‘coal flow’ multiplies ‘CV’. Therefore, under the same output (MW), when CV is small, fuel flow increases and when CV is big, fuel flow decreases. If we use this CV as it is, it is difficult to control output precisely, therefore, we should correct CV. It is normal for thermal power plant to furnish CV correction logic.

We reviewed control logic of Vindhyachal No.11 unit, and we understood there exists CV correction logic, however CV is not renewed properly. To renew CV properly, we suggest modifying control logic. Addition to this, actual band of CV correction of Vindhyachal No.11 unit is plus minus 3%, but real CV fluctuate plus minus around 9%, therefore range of CV correction should be extended.

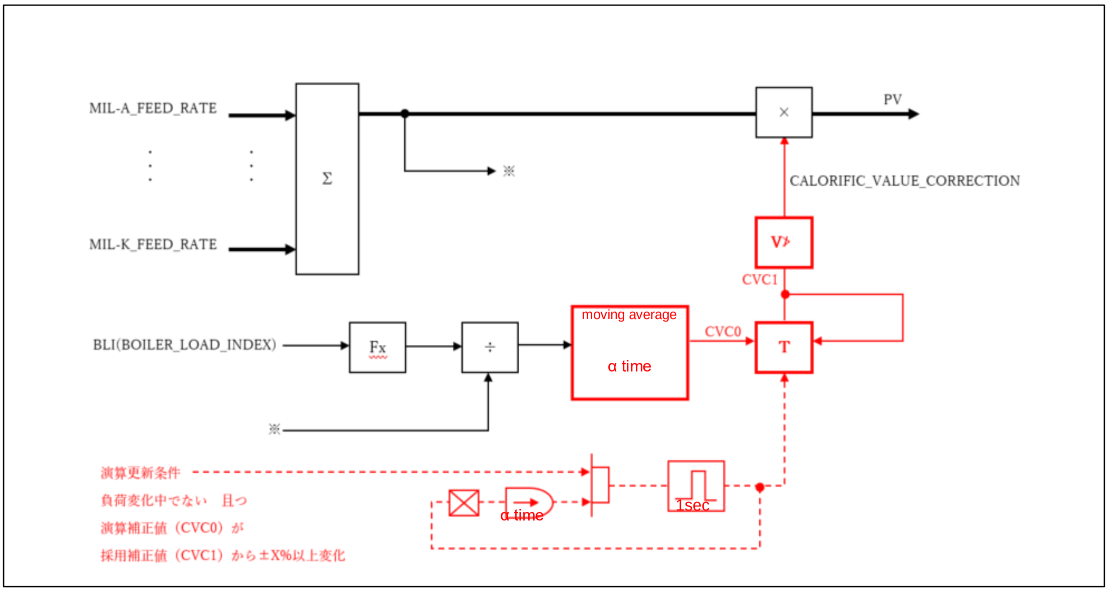


Figure 2-26 proposed control logic of fuel flow

4) Correction of Gap between ‘measured Coal Flow’ and ‘real Coal Flow to Burner’

It takes minutes from coal injection to mill, up to pulverized coal injection to burner. Coal flow used for plant control is measured at coal feeder, therefore there exists some difference between measured coal flow and real pulverized coal flow to burner. And this difference has harmful influence on plant control. Therefore, we suggest adding ‘artificial Coal Flow generating logic’ which calculate ‘estimated coal flow to burner’ by using ‘measured Coal Flow at coal feeder’.

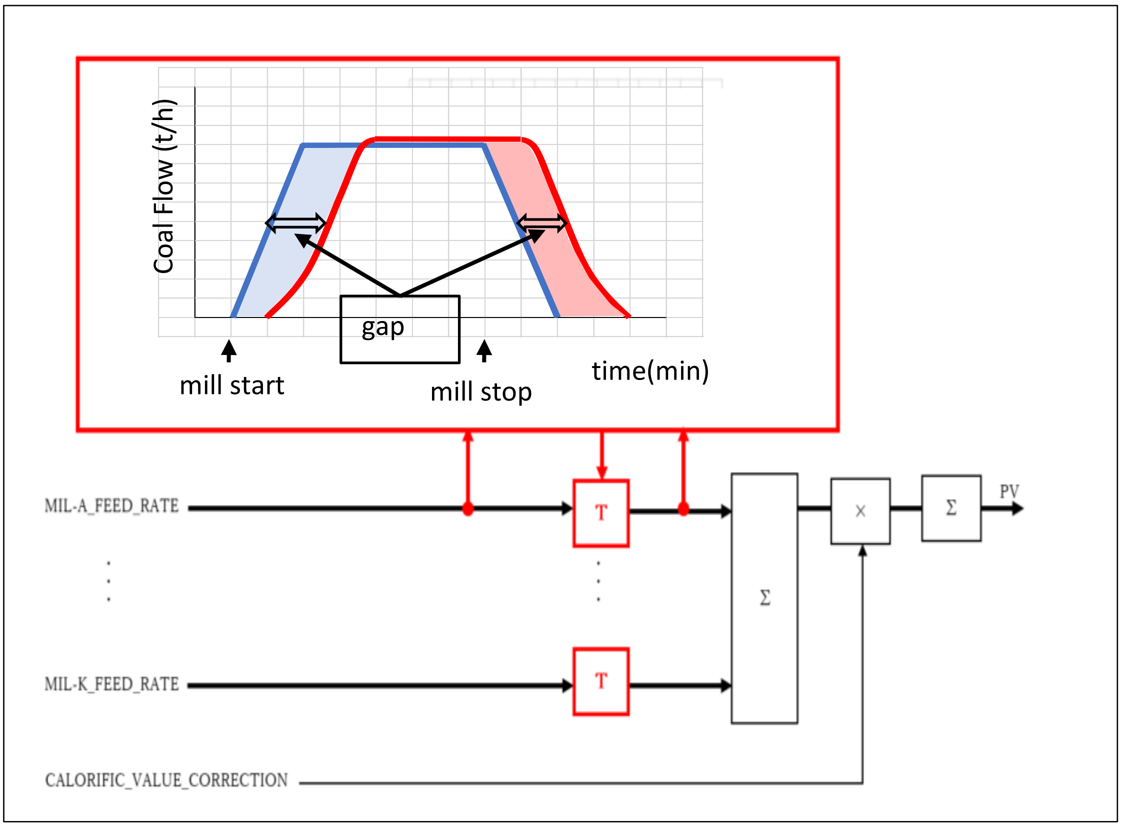


Figure 2-27 proposed control logic to make simulated coal flow

5) Optimal tuning of control system

It is very important that statistical data of control system should match with characteristics of real plant. We would like to introduce how we tune our control system.

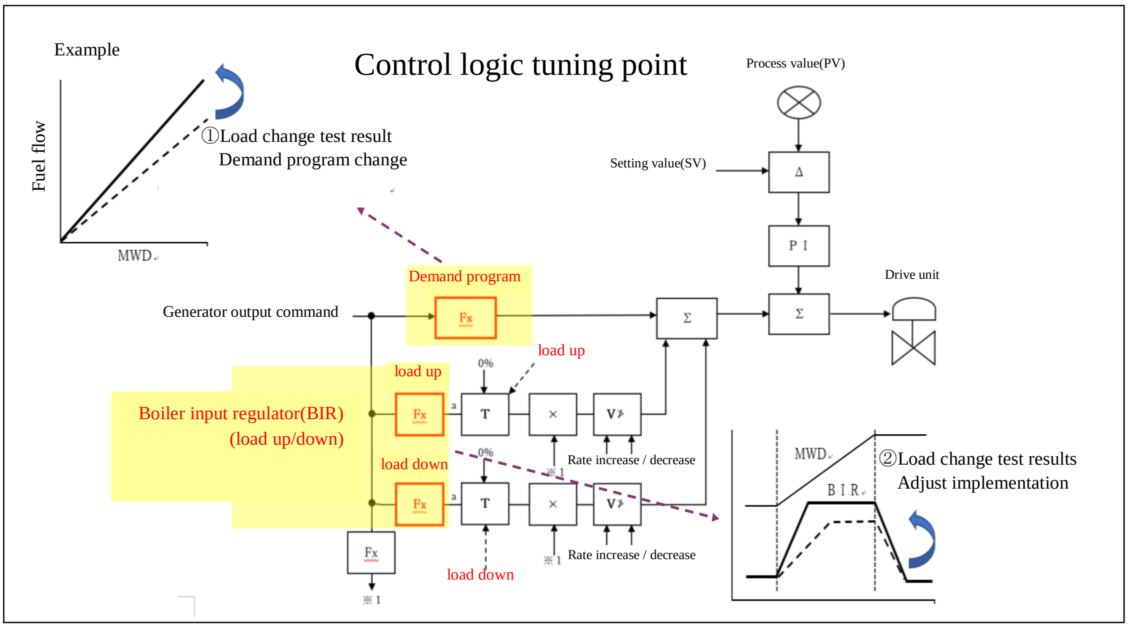


Figure 2-28 tuning of control system

At first, by the operating test of 50%MCR, 75%MCR and 100%MCR, obtain static data of key process such as fuel flow, air flow and feed water flow etc. And by using these data, generate each static characteristic function curve (FX curve). In order to accelerate the response of each control logic, adjustment of Boiler Input Regulator (BIR) is important, therefore by ramp down/up test, evaluate the behaver of control system and adjust control system.

And as for dynamic characteristic adjustment, by ramp down/up test based on the estimated load curve, evaluate the behaver of control system and adjust control system.

In addition, since the controllability also changes depending on the coal properties, it is desirable to first perform static characteristic / dynamic characteristic test adjustment with reference coal and then to carry out dynamic characteristic test of low calorific value coal and the like.

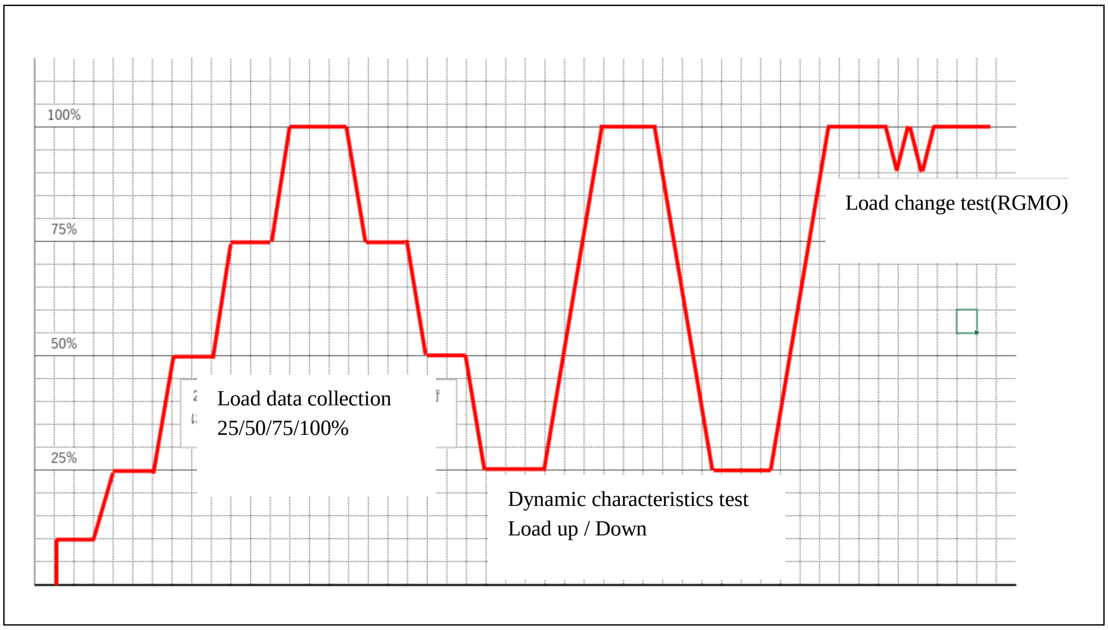


Figure 2-29 proposed load curve of heat run test and ramp down/up test

(2) Lower minimum load

Improvement and addition of control logic and tuning of control system enable No.11 unit to be operated stably. And by this, lower minimum load becomes possible. We set a target of minimum load as 250MW. At a load of 250MW, one of feed water pump may be able to stop and thermal efficiency at 250MW expects to be increased.

1) Air flow test

During the operation of low load, fuel flow and air flow decrease, and balance of fuel and air sometimes collapses at some space in furnace of boiler, and combustion becomes unstable.

At coal thermal power plant, one mill provides pulverized coal to several burners. To keep combustion stable, it is important to make pulverized coal flow rate to each burner should be almost same.

Therefore, before ignition, we recommend to adjust air flow to each burner almost same by orifice.

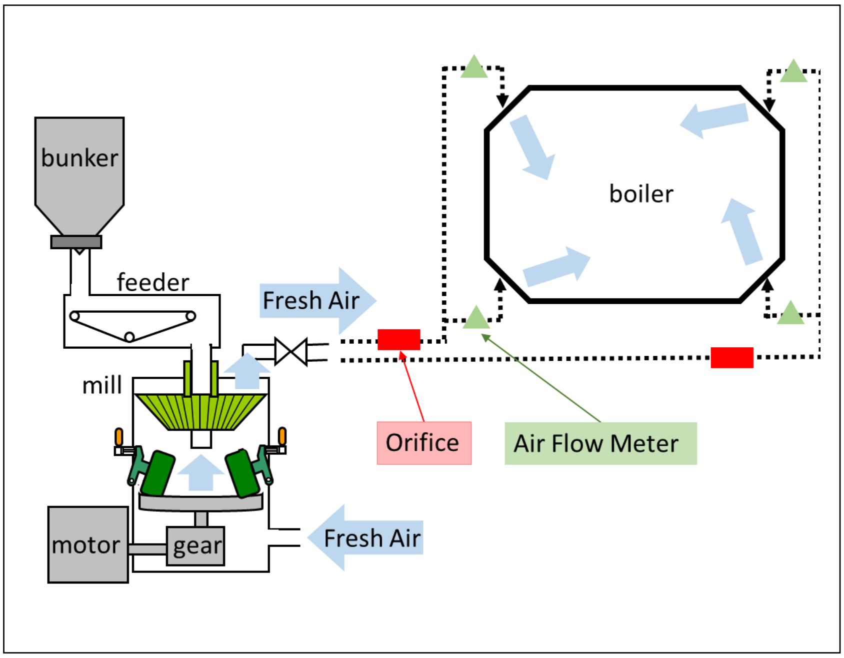


Figure 2-30 Air flow test

2) test of lower minimum load

No.11 unit has very few experience to operate under 275MW. Therefore, load of No.11 unit should be reduced very carefully and combustion situation and controllability of control system should be observed with attention. And also operational data regarding safety as follows, should be monitored.

[operational data to be monitored]

- Main steam pressure
- Main steam temperature
- Furnace pressure
- Differential pressure of Air Heater
- Fuel flow
- Gas temperature at outlet of furnace
- Boiler metal temperature
- Drum level
- Gas O2 at outlet of economizer

We assumed the risks which bring with lowering minimum load.

Table 2-5 Risks which bring with lowering minimum load

No.	Risk	Contents
1	Difficulty to control steam temperature	Steam temperature control becomes difficult as fuel flow rate and feed water flow rate decrease.
2	Abnormal combustion such as increase NOx, partial overheating	Fuel flow and air flow decrease, and balance of fuel and air sometimes collapses at some space in furnace of boiler, and combustion becomes unstable.
3	Steaming at Economizer	Steam pressure decreases with lowering load, at the economizer, the feed water temperature may approach saturated liquid temperature, and evaporation may occur. If evaporation occurs, the feed water flow may be interrupted and the metal temperature of the water cooling wall may rise.
4	Internal failure of steam turbine	Contact between turbine rotor and a labyrinth part by the thermal expansion difference.
5	Difficulty to control HP feed water heater	With lowering load, amount of steam entering the feed water heater decreases, and the amount of drain also decreases, therefore it becomes difficult to control the drain level.

3) Combustion surveillance television

At No.11 unit, combustion surveillance television is not installed. As for conventional type thermal power unit of JERA, each boiler is equipped with combustion surveillance television. Combustion surveillance television is very useful to observe combustion situation, this enable us to detect misfire. We recommend to install combustion surveillance television.

Figure 2-31 Combustion surveillance television

(3) Shorten startup time

Startup time from ignition to rated output operation of hot start mode dated 31st July 2018 is 227 minutes. This record is longer than design startup time, however this is short enough compared with the record of No. A unit of Japan, therefore we understand there is no need to shorten startup time further.

(4) Improve partial load efficiency

1) Recovery of thermal efficiency

We reviewed operational data and found that adiabatic efficiency of HP turbine declined. If adiabatic efficiency of HP turbine will be recovered, the thermal efficiency of the unit may also be recovered not only at the partial load operation but also at the rated load operation. At JERA's power unit, we had an experience of declining adiabatic efficiency of HP turbine. At that time, when we implemented open inspection, significant erosion was found at the first stage stator blade. In addition to this, thinning of first stage rotor blade and downstream rotor blade were also observed.

We recommend to inspect inside of HP turbine during periodical inspection.

Table 2-6 Causes of declining adiabatic efficiency of HP turbine

No.	Causes	Countermeasures
1	Steam leak from seal ring of nozzle box	- Periodical replacement of seal ring
2	Steam leak from tip fin	- Implement measurement of gap of tip fin during periodical inspection - Replace radial spill strip inn case when gap is larger than specified value
3	Scale stick at blade and nozzle	- Improvement of water quality management - Cleaning steam path such as blade and nozzle
4	Deterioration of surface of blade and nozzle	- Build up welding repair - Replacement of nozzle

When HP turbine recovers its efficiency to design basis, thermal efficiency of unit recovers from 34.72% to 35.05%. And if planned maintenance including exchange of deteriorated equipment is well implemented, thermal efficiency of unit may have a potential to be recovered up to design efficiency.

2) Optimization of number of operating BFP during operation of 250MW

We calculated turbine efficiency by drawing diagram of heat balance of 250MW operation with one BFP. The result is 41.31% and this is 0.09% higher than turbine efficiency of 250MW operation with two BFP.

And during 250MW operation with one BFP, if we assume boiler efficiency 84%, thermal efficiency of unit is calculated to be 34.70%. This is 0.08% higher than thermal efficiency of unit of 250MW operation with two BFP.

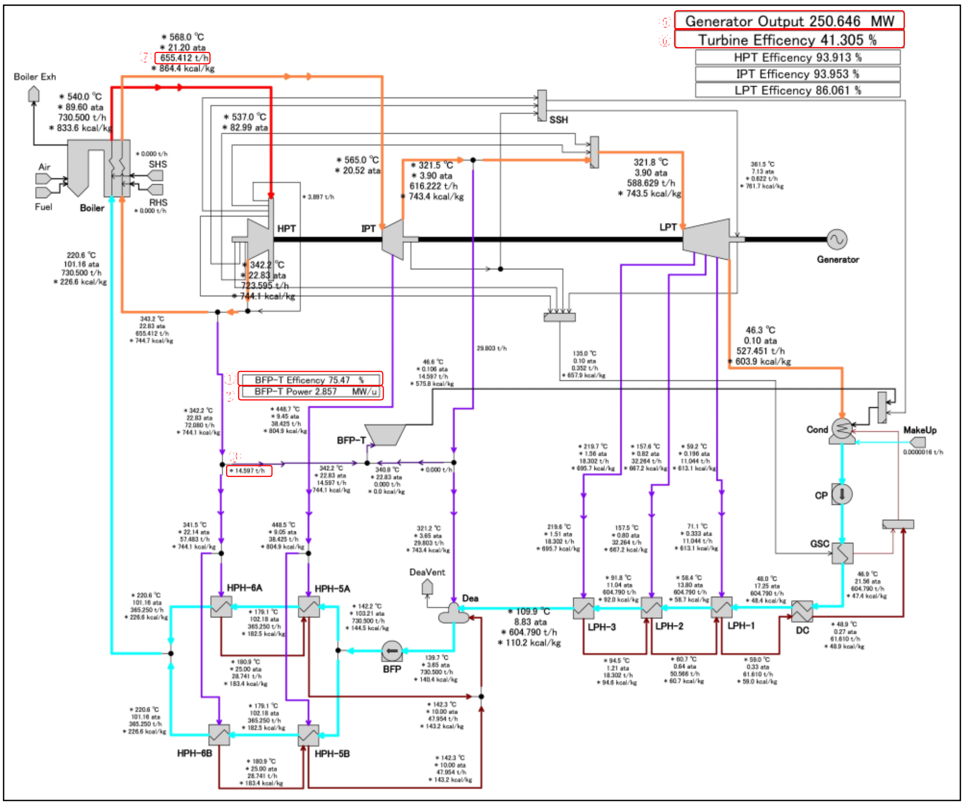


Figure 2-32 Heat balance of 250MW operation with one BFP

(5) Others Improvement of frequency control

In Japan, network frequency is controlled by inertia force of generator, governor free operation and Automatic Dispatch Control system(ADC) which consists of Load Frequency Control system(LFC) and Economic Load Dispatch Control(EDC).

Power demand disassembles into ‘Sustained element: long period’, ‘Fringe element: short period’ and ‘Cyclic element’.

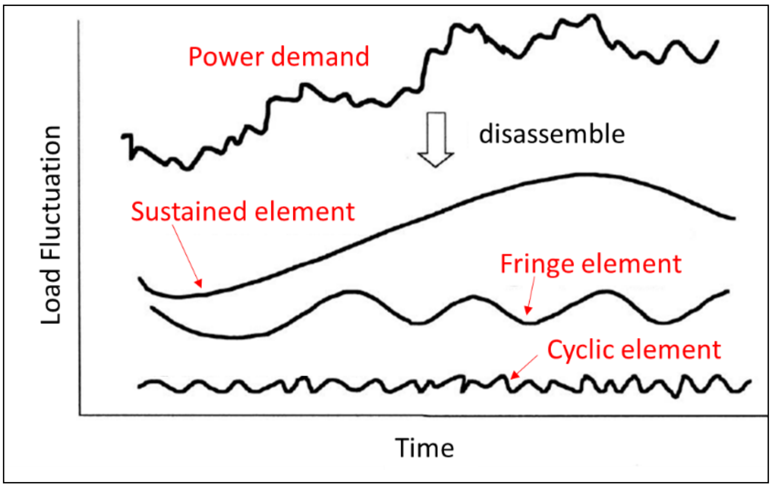


Figure 2-33 Elements of Load Fluctuation

In Japan, depends on the load fluctuation element, method of frequency control differs. For very short period of load fluctuation (Cyclic element) up to around 10 seconds, inertia of generation is mainly used for frequency control. For short period of load fluctuation (Fringe element) between few seconds to around 1 minute, the function of governor free which is originally equipped at steam turbine is mainly used for frequency control. For long period of load fluctuation (Fringe & Sustained element) between around 1 minute and around 15 minutes, LFC which detects network frequency around every 10 seconds mainly controls output of plants. For much longer period of load fluctuation (Sustained element), EDC which calculates optimum combinations of power plants every few minutes mainly controls output of plants. By these methods, frequency is controlled precisely and power plants are operated economically.

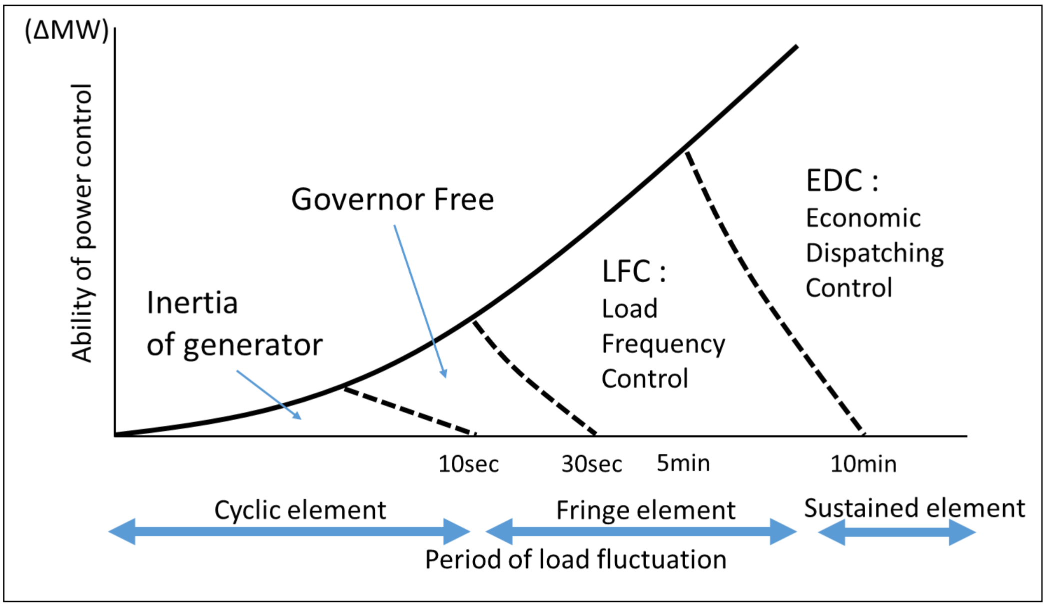


Figure 2-34 Method of frequency control

In India, trial operation of AGC (Automatic Generation Control) at Dadri power plant commenced 4th January 2018, but at this moment AGC is not installed to other plans. Frequency should be controlled automatically. We recommend to install AGC to each power plant and improve quality of frequency control.

2.3

2.3 Consideration for introducing optimized operation method for one group of power units

2.3.1 What is optimized operation method for one group of power units

Optimized operation method for one group of power units

Possible impacts from the optimized operation on a group of power units accommodating changes in electricity demand for coal-fired thermal power were examined considering the scenario for the renewable energy policy introduction in India.

(1) Concept of optimized operation method for one group of power units

Optimized operation analysis on a group of units assigns weighted output to highly economic units in light of operational limitations including periodic inspection and power generation cost of each unit. Figure 2-33 shows a conceptual diagram of this analysis.

The power generation cost of a thermal power plant largely varies depending on its fuel cost, age of the equipment, operating record, equipment configuration, labor cost for plant operation and maintenance cost. It is vital for thermal power producers to minimize the total operation cost by operating a group of generation units with the optimal output distribution considering the cost of each generation unit in operating the power unit.

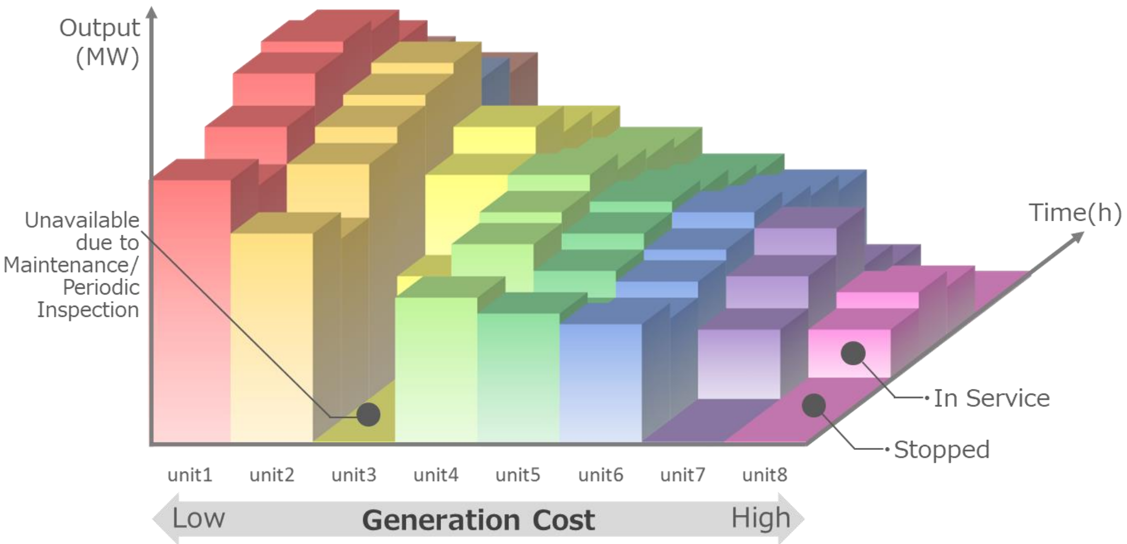


Figure 2-33 Optimized Operation Method

(2) Method of Examination

This project employed an approach shown in Figure 2-34. An optimized operation analysis of the 13 units was performed based on the fuel consumption and data analysis calculated based on the operating record of VSTPS. Improvement measures that can contribute to overall reduction of the fuel consumption were developed and presented by comparing the actual fuel consumption and the fuel consumption obtained after running the operational simulation.

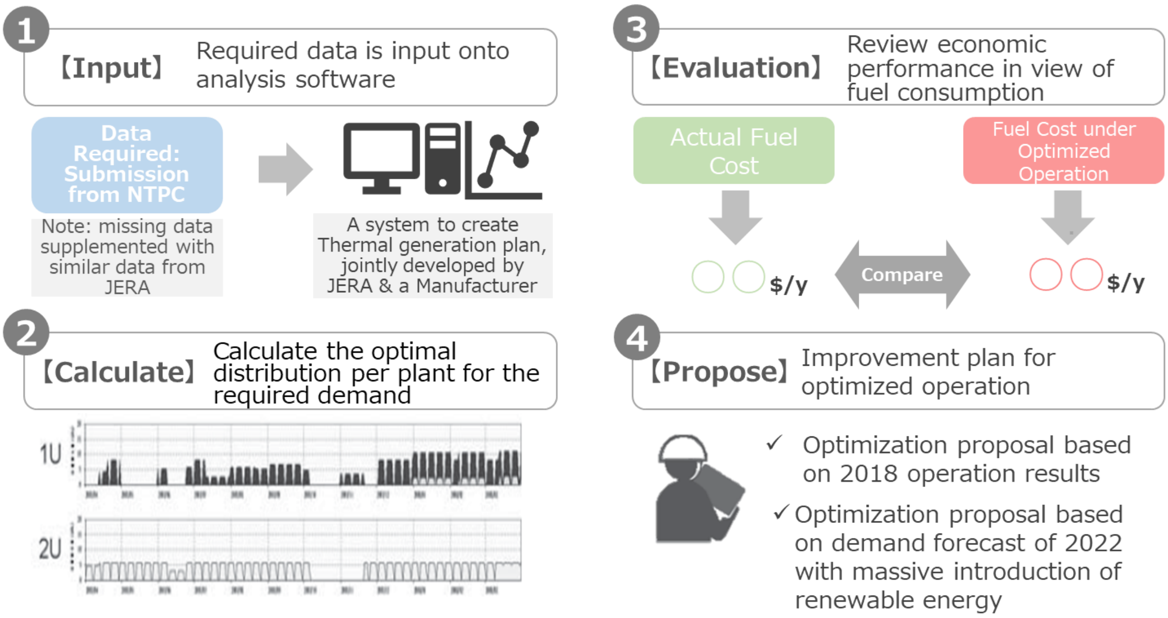


Figure 2-34 Approach Taken for Optimization of Plant Operation

Additionally, two scenarios, as described below, were used to examine and propose the appropriate optimization of the plant operation in this project.

<u>(a) Optimized operation method based on the track record of the 2018 demand of the target plant</u>

- Simulated outcome of the optimized operation was developed, utilizing JERA's simulation system based on the optimal output distribution computated using the thermal efficiency of the current equipment, which was obtained using the actual 2018 VSTPS demand record.
- Economical performance review was carried out by comparing the actual fuel consumption in 2018 VSTPS power generation record and the simulated fuel consumption when adopted optimized operation analysis of one group of power units.

<u>(b) Optimized operation method based on demand forecast for 2022 following the large-scale introduction of renewable energy</u>

- Government of India is planning to introduce large-scale renewable energy by 2022. It is, therefore, expected that Indian power producers will be required to operate the various plants with flexibility corresponding to large output fluctuations in the solar, wind or other renewable sources. Optimized operation of the target power plant was examined in view of these expected changes in the business environment.
- Expected fluctuation in the future load demand of the target power plant was predicted based on the 2022 Indian renewable energy target set by the government of India.
- Optimized operation method was proposed considering two optimal output distribution scenarios using JERA's simulation system. First optimal output distribution approach was developed by analyzing the current equipment performance against the required demand, and the second optimal output distribution approach was obtained taking into account the

potential performance improvement as a result of the measures etc. proposed in 2.2.

- Economical performance review was derived by comparing two fuel consumption estimates: the fuel consumption estimated based on the current operation method compared with the fuel consumption when operated according to the optimized operation method proposed in this project.

2.3.2 Data analysis

(1) Received data

Prior to the kick-off meeting held on January 28, 2019, the required data list in Table 2-8 had been sent to NTPC, and the necessity of each data, possible submission of those data to JERA, availabilities of those data at VSTPS and respective submission deadlines were confirmed on the day of the meeting.

Table 2-8 Required Data List

Required data

Required data		note	On target unit		Data receipt deadline			
			500MW plant (7units)	ALL plant (13units)	21 Jan 2019	28 Jan 2019	04 Feb 2019	11 Feb 2019
1	Minimum utilization under the Power Purchase Agreement			○		○		
2	Annual operation data	Data described in 2-1～ 3						
2-1	availability			○		○		
2-2	capacity factor			○		○		
2-3	forced outage rate			○		○		
3	Maximum electricity demand value (every 30 minutes or 1 hour)	"demand"=generated output are instructed from load dispatch center		○		○		
4	Rated output			○		○		
5	Minimum output	Basis determining minimum output		○		○		
6	Output rate of change (Power curve)	Maintained output when switching mills		○		○		
7	Starting characteristics curve Stopping characteristics curve			○		○		
8	Mismatch chart					○		
10	Start and Stop loss			○		○		
11	Coal unit price	Fuel used and fuel unit price for each plant (Please tell us the average value if using multiple fuels)		○		○		
12	Unit calorific value	Fuel used and Unit calorific value for each plant (Please tell us the average value if using multiple fuels)		○		○		
15	Actual coal mixing ratio	In case of burning multiple coal (fuel) at the same time		○		○		
16	Thermal efficiency	Please provide design value of the thermal efficiency, deterioration curve and actual trend from COD. Also please provide turbine efficiency and boiler efficiency.		○		○		
17	Auxiliary power ratio	Please provide design value of the auxiliary power ratio, deterioration curve and actual trend from COD.		○		○		
18	Any other restrictions	e.g. minimum number of operating units, total minimum output(MW) etc.		○		○		

Besides the listed data, JERA has received from NTPC a set of the generation reports, from January 1 to December 31, 2018 and the demand profile with 30-min interval for each power generation unit.

(2) Characteristics of supply-demand operation and overall plant operations in 2018 at VSTPS according to the VSTPS data

VSTPS owns a total of 13 power generation units (210MW x 6 units, 500MW x 7 units), but these 13 units are divided by five different PPAs (PPA: Power Purchase Agreement). As shown in Table 2-9, each power generation unit is grouped into Stages-I to -V according to the PPA.

Table 2-9 Relationship between Generation Equipment at Target Plant and PPA

Generation Equipment / PPA	210MW【Boiler: LMZ, Turbine: Electrosila】						500MW【Boiler: BHEL, Turbine: BHEL】						
	Unit-1	Unit-2	Unit-3	Unit-4	Unit-5	Unit-6	Unit-7	Unit-8	Unit-9	Unit-10	Unit-11	Unit-12	Unit-13
Stage-Ⅰ	○	○	○	○	○	○							
Stage-Ⅱ							○	○					
Stage-Ⅲ									○	○			
Stage-Ⅳ											○	○	
Stage-Ⅴ													○

Indian power grid system is operated by NLDC (National Load Dispatch Center), RLDC (Regional Load Dispatch Center) and SLDC (State Load Dispatch Center). Supply-demand operation is created and changed for 15-minute-block schedule by SLDC, and the output command is sent from the dispatch center to each power producer. At the target power plant, an output command from SLDC is requested for each Stage shown in Table 2-9.

Figure 2-35 and Figure 2-36 show 2018 annual demand of the target plant. The survey team created these figures based on the 15-minute output command data issued for each Stage in VSTPS.

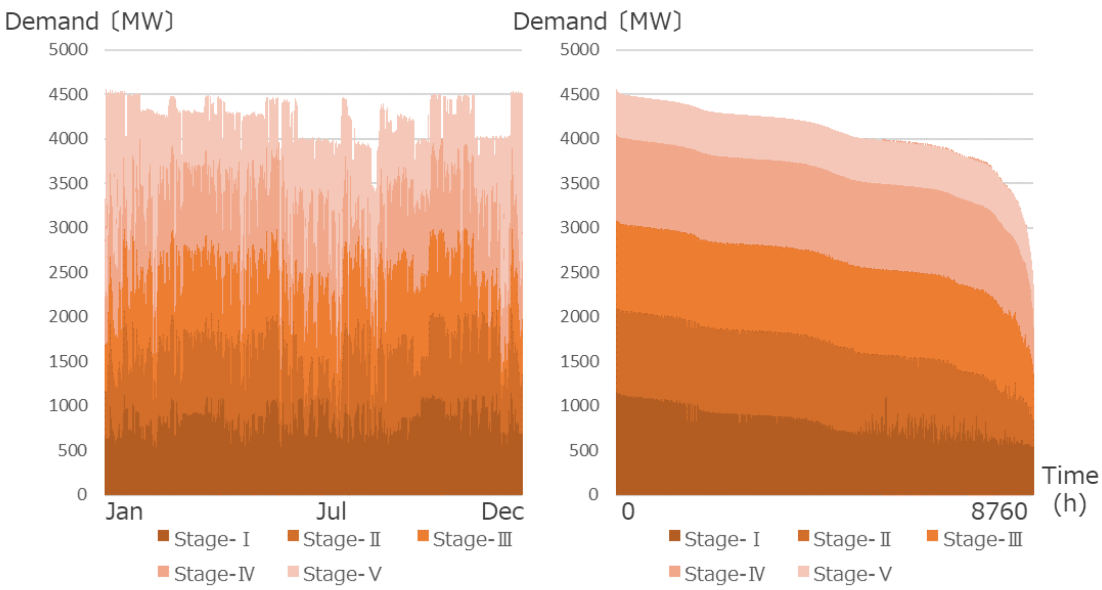


Figure 2-35 Annual Demand Record of 2018 (left)
Figure 2-36 Duration Curve of 2018 (right)

Although the demand of VSTPS may be lower at times, the maximum daily demand stays almost flat throughout the year. 4,500MW is generated almost all year round while peak demand sometimes reaches 4,000MW.

Also, as seen in the duration curve, the difference between the peak and the bottom is minimum. Currently, the demand remains high in most periods, and the high demand continues for approximately 8,500 hours.

The unit generation cost at VSTPS is 1.5 RS/kWh, which is exceptionally inexpensive compared to 2.5 RS/kWh, the average price in India. VSTPS, therefore, is currently placed as a baseload power source. The fluctuation in demand for the year is considered to be relatively small.

(3) Characteristics of VSTPS operation observed in the VSTPS data

Figure 2-37 exhibits power generation records for each unit from January 1 to December 31, 2018 at VSTPS.

The data indicates that the annual output fluctuation is rather small, and the power plant is always operating at around the rated load albeit the period of periodic inspection etc., when the operation is stopped. The Figure 2-37 additionally indicates that, how the output command from the grid side is assigned to each unit in every proportioned manner. Upon receiving the output command for each Stage from the grid side, the load factor for each unit is distributed by simply dividing the command output from the grid by the number of units.

The site survey was conducted, and the result indicated that, in the central control room at VSTPS, there is a monitor which displays the output command per target Stage which was issued from the grid side in 15-minute time block for the next one hour. The local operators manually determine the output of each unit corresponding to the command from the grid. Interviews with the local operators about the concept of power distribution revealed that no clear rule regarding the output distribution is defined in the manual and that the generation command from the grid system is simply and equally divided by the number of units belong to each Stage.

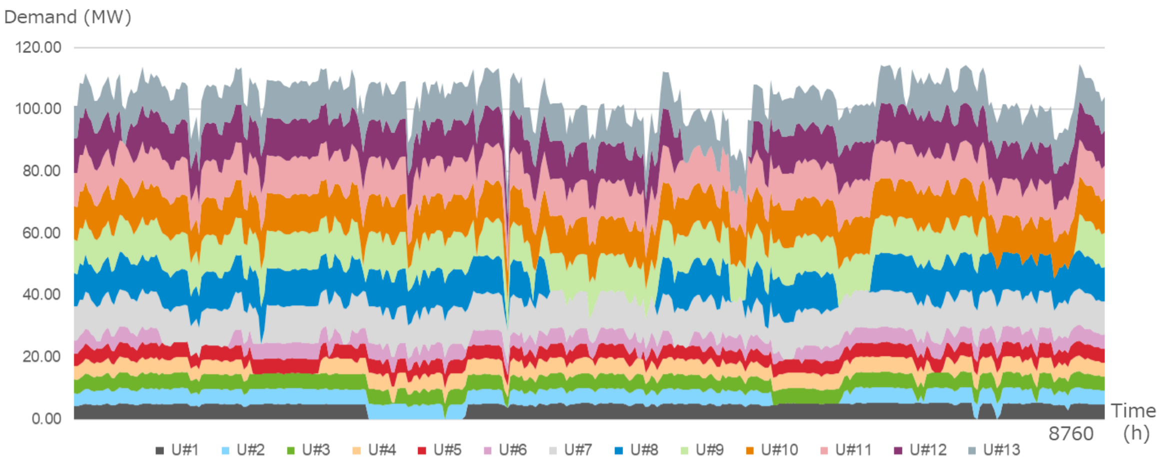


Figure 2-37 Power Generation Track Record of 2018 at VSTPS

As described in 2.3.1- (1), one group of power units needs to be operated with highly economical output distribution considering the generation cost of each unit, reflecting the optimal operation analysis.

The average thermal efficiency of 2018 was selected, out of the various data received from VSTPS, as a criterion to measure the economic efficiency of each unit at VSTPS since there was no significant difference among the cost and calorific value of the fuel used, which can greatly impact the efficiency.

Figure 2-38 indicates the relationship between the average thermal efficiency and plant utilization factor of each unit at VSTPS in 2018. Potential of operational improvement was analyzed by grasping the correlation between the economic efficiency of each unit and the actual operational priority given within the same Stage.

The utilization factor refers to the ratio of an actual amount of output generated at the target generation facility over a given period of time to the maximum possible energy output over that period excluding the time when the operation is stopped (periodical inspection etc.).

The calculation formula is as follows.

$$\textbf{Utilization Factor}(\%) = \frac{\textbf{Actual Power Produced}(\mathrm{MWh})}{\textbf{Plant Capacity}(\mathrm{MW}) \times \textbf{Hours of Operation (h)}}$$

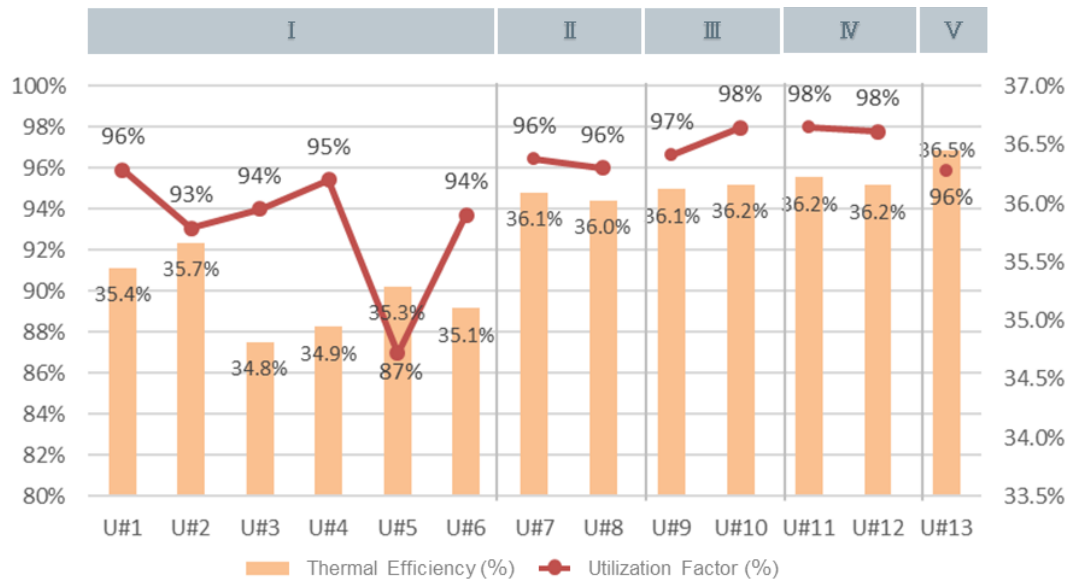


Figure 2-38 Relationship between Thermal Efficiency and Utilization Factor of Each Unit at Target Plant

Stage-II to Stage-V exhibited virtually no difference in its thermal efficiency of each unit, and each unit indicated very high utilization factor during operation with little difference. Therefore, it can be said that, considering the 2018 operating record, no notable impact on the operation of the Stage-II to -V could be expected even if the optimized operation were to be introduced to those Stages.

Stage-I, on the other hand, exhibited some variations in the thermal efficiency among each unit. Plant utilization factor of Unit-5, which demonstrates relatively high thermal efficiency, was significantly low. It was initially assumed that this was due to the output restriction associated with the replacement of the electrostatic precipitator (ESP). After interviewing the local operator, however, it was found that Unit-5 could be operated at 85% - 90% load even during the replacement period. Therefore, it is concluded that the availability of Unit-5 was too low even taking into account the possible output suppression caused by the ESP replacement.

Stage-I was assumed to have a room for improvement; therefore, it was decided that optimized operation method would be introduced to the six units of the Stage-I.

2.3.3 Simulation analysis

(1) Method of simulation

JERA co-developed a simulation system with a manufacturer in order to correspond to the system reform in Japanese electricity market, which simulation allows us, as a power producer, to create a power generation plan that supports to the forecasted demand. Optimal operation analysis for Stage-I (210MW x 6 units) was created using this original simulation system.

In the analysis, about 100 basic conditions including unit thermal efficiency, output, lamp rate, power generation cost, etc. and about 60 operational restrictions including limitations on the start/stop, output suppression, and fuel constraints, those which have a great impact when determining operating status and generation output, were entered as variable data so that an optimal generation output for each unit reflecting the demand from the system can be obtained.

Data that we had received from VSTPS was the only data we have input to the simulation system. There were some data we did not receive which were required for simulation; however, missing data were supplemented with equivalent data from similar plants of JERA.

(2) Demand forecast based on the 2022 renewable energy introduction plan

CEA issued “National Electricity Plan” in January 2018. Our scenario was created, based on the CEA's plan, to predict the impact of introducing renewable energy to VSTPS.

Indian government has set an target of having 175 GW of clean energy capacity by 2022, including 100 GW solar and 60 GW of wind energy. 90% or more of the overall equipment configuration in India shall be occupied with these two renewable sources.

"National Electricity Plan" by CEA illustrates a probable "typical day" duck curve following the full introduction of the renewable energy capacity target, shown in Figure 2-39. This represents a load curve of the total demand and the net demand (the total demand minus the power generated by solar and wind) for thermal power generation on the "typical day" in India. CEA forecasts that the daily net demand in India will be decreased by an average of about 12% from the gross demand (Replaced by renewable energy). In particular, it can be seen that the net demand is greatly reduced when solar power is available to the grid, from 8:00 to 18:00.

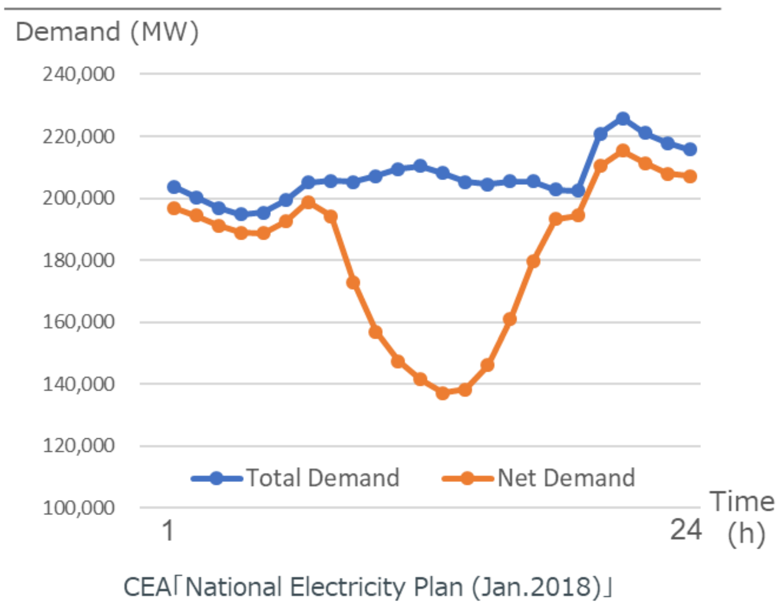


Figure 2-39 Total Demand and Net Demand on a "Typical Day" in India

Source: CEA "National Electricity Plan" (2018) http://www.cea.nic.in/reports/committee/nep/nep_jan_2018.pdf

Visited on May 10, 2019 from office of JERA East Japan Branch

This scenario was applied to the entire period of VSTPS FY 2018 in a uniform manner and used to predict the demand for the power plant in 2022. Figure 2-40 shows the power demand on a "typical day" in VSTPS.

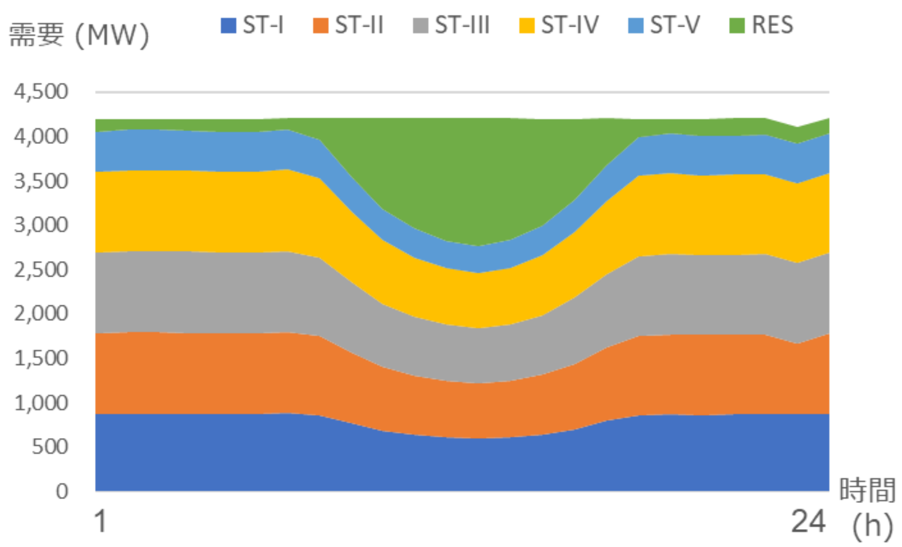


Figure 2-40 Demand Scenario on a "Typical Day" at Target Plant

Note) RES in the Figure stands for Renewable Energy Source

Primarily, it is necessary to adjust and balance the load of renewable energy depending on the season and climate in interest of making an accurate forecast. In India, it is necessary to consider the influence of renewable energy for each connected grid as described in Chapter 1, but the demand scenario referred for this project does not show detailed forecasts for each grid system.

In India, solar, generally a major cause of output power fluctuations, is, however, rather stable throughout the year regardless of the season. During the monsoon (rainy) season, the amount of solar power generation is reduced while the wind power generation increases with substantially strong winds from the monsoon. The impact of seasonal and climatic fluctuations, therefore, is considered to be smaller than that of Japan because the increased wind power complements the shortage of sunlight.

In view of the above, it was decided to uniformly apply the demand scenario to all periods for this project.

The two duration curves shown in Figure 2-41 and Figure 2-42 were created from the demand based on 2018 track record and the demand forecast referred above.

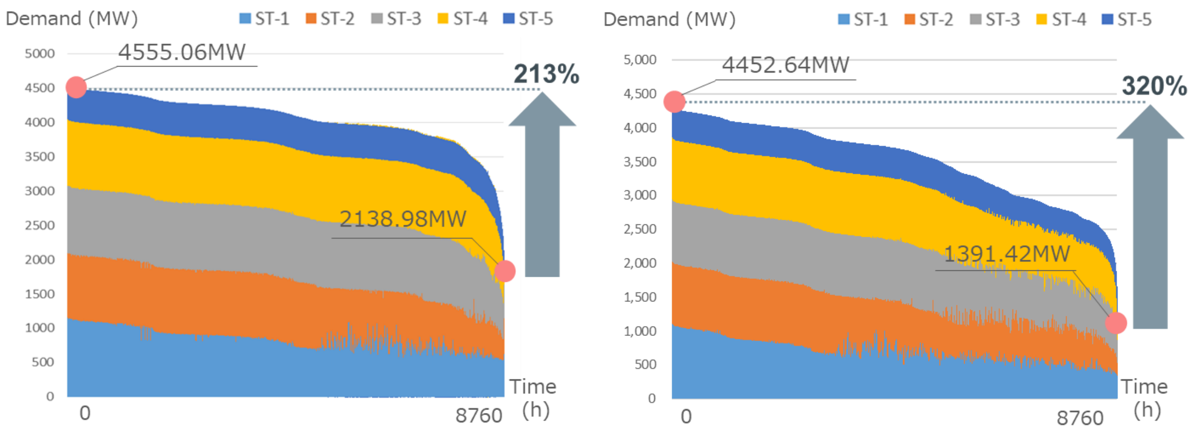


Figure 2-41 Duration Curve Based on 2018 Operating Track Record (left)
Figure 2-42 Duration Curve Based on Renewable Energy Introduction Scenario (right)

Based on this scenario, when a large amount of renewable energy was to be supplied to the grid connected to VSTPS, it is assumed that the difference between the maximum and minimum demand of VSTPS would be increased by about 1.5 times compared with the 2018 results.

This means that VSTPS, now a baseload power plant, would likely be required to operate with focuses on economic efficiency in order to accommodate large load fluctuations expected in the future.

(3) Proposal on Optimized Operation Method

In this Chapter, analysis based on: (a) optimized operation method based on the track record of the 2018 demand for VSTPS, and (b) demand forecast for 2022 following the large-scale introduction of renewable energy, were performed to propose the optimized operation method for each scenario.

Additionally, the incentive that VSTPS may be granted by adopting the proposal is described in 2.3.4 “Economic performance review”.

a. Result of optimal operation analysis based on the track record of 2018 at VSTPS

a-1：Merit order operation method

The relationship between the thermal efficiency of Stage-I and the utilization factor of each unit during operation in VSTPS is shown again in Figure 2-43.

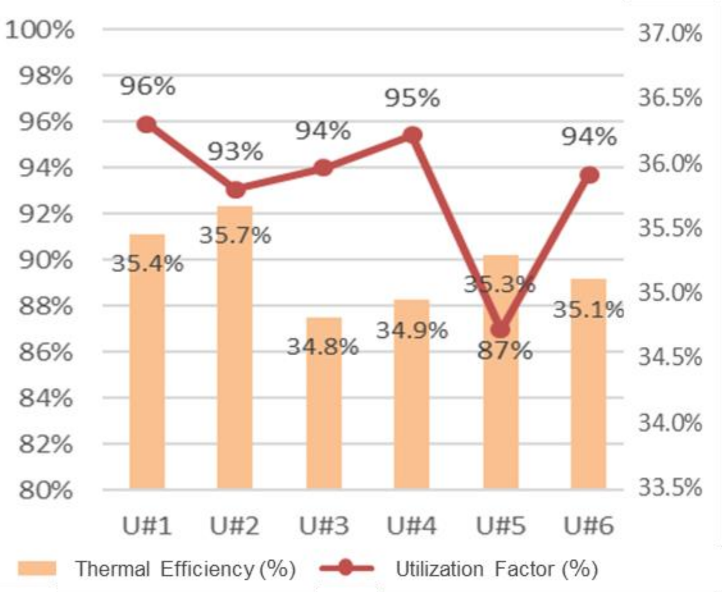


Figure 2-43 Relationship between Thermal Efficiency and Utilization Factor of Stage-I of Target Plant

In Stage-I, Unit-2 shows the highest efficiency then followed by Unit-1, Unit-5, Unit-6, Unit-4, and Unit-3. In the actual operation, however, the utilization factor during operation increases from Unit-1, Unit-4, Unit-3, Unit-6, Unit-2 to Unit-5. These sequences show that merit order operation is not always applied to Stage-I of VSTPS. The merit order ranks and operates various generation units in ascending order of the generation cost, so the units with the low generation costs are operated first.

Demand changes gradually according to the season and climate, but JERA normally operates supply-demand basis utilizing the merit order from a viewpoint of securing economic rationality.

Plant operation at VSTPS demonstrates a little fluctuation in output and many hours at the rated load. However, a large fuel consumption reduction can be achieved by taking into consideration the thermal efficiency of the unit when distributing power at the time of partial load operation. Therefore, in this project, it is recommended that NTPC adjusts the output in the merit order basis, according to the thermal efficiency of each unit.

b. Result of optimal operation analysis based on demand forecast for 2022 following the large-scale introduction of renewable energy

Two methods are proposed after reviewing the scenario.

b-1 : <u>Merit order operation method</u>

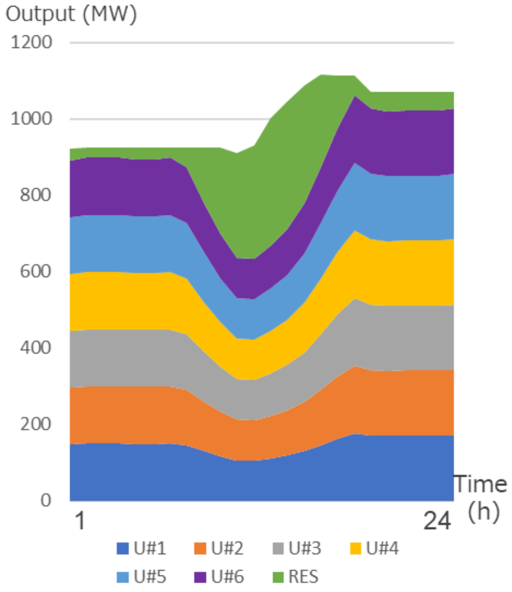
This is the same operation method proposed in a-1.

The following two graphs are the lord curves on the "typical day" at VSTPS reflecting the renewable energy introduction forecast in 2022 mentioned in the previous section. The left and right figures show different output distributions for the units that make up Stage-I.

As indicated in 2.2.2- (2), current VSTPS operation is characterized by 2 figures distributing the demand evenly among all units when receiving the output command. Figure 2-44 on the left shows the simulation result when operated the unit according to this original characteristic.

The Figure 2-45 on the right shows the simulation results when introduced the merit order operation method.

As indicated in these figures, in the daytime hours, when the solar power output increases and the demand for thermal units in Stage-I drops, highly economic Unit-2 and Unit-1 maintain their rated load, while Unit-5 operates in the load following mode. Supply and demand are balanced by operating Unit-6, Unit-3 and Unit-4, units with low economic efficiency, at minimum load.



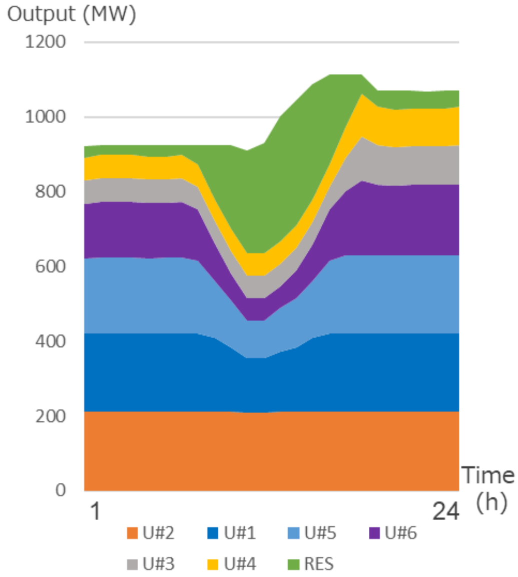


Figure 2-44 Load Curve on "Typical Day" Based on Current Operation Method (left)

Figure 2-44 Load Curve on "Typical Day" Based on Merit Order Operation Method (right)

Note) RES in the Figure stands for Renewable Energy Source

b-2 : DSS operation method

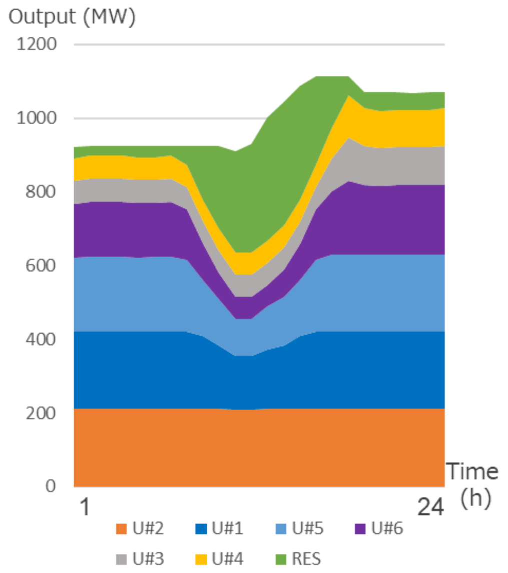
The DSS (Daily Start and Stop) operation method refers to stopping rather inefficient units during a low-demand hour.

At JERA, we have observed the change in the daytime demand has expanded together with the growth in renewable energy and energy saving awareness among general consumers. As a result, certain power plants are now operated as DSS almost every day. Although the demand varies depending on the season, it generally peaks after noon during the day and drops to to about 70% at midnight. So JERA's thermal power plants are often included to be operated only during the day the power demand is high and stopped at night.

DSS operation requires the unit to have high flexibility, so separate operational improvement such as shortening of start/stop duration, reduction of starting loss and improvement of thermal efficiency during partial load operation is required. It is recommended to combine the merit order and the DSS operation methods since such operations would be rather practicable by implementing the improvement measures recommended in 2.2.

The load curve of VSTPS is shown below. Figure 2-46 on the left is the simulation result when the aforementioned merit order operation method is applied. Figure 2-47 shows the simulation result when the DSS operation method is introduced.

In the simulation, the post-evening demand continues to be high. Unit-4 with low thermal efficiency is, in fact, stopped until the evening and starts to operate again after the demand increases (DSS). Unit-2, Unit-1 and Unit-5 with high unit thermal efficiency are given priority to operated at the rated load. Low-in-efficiency Unit-6 and Unit-3 are operated, with combination of merit order, by suppressing the output to the minimum load depending on the time of the day.



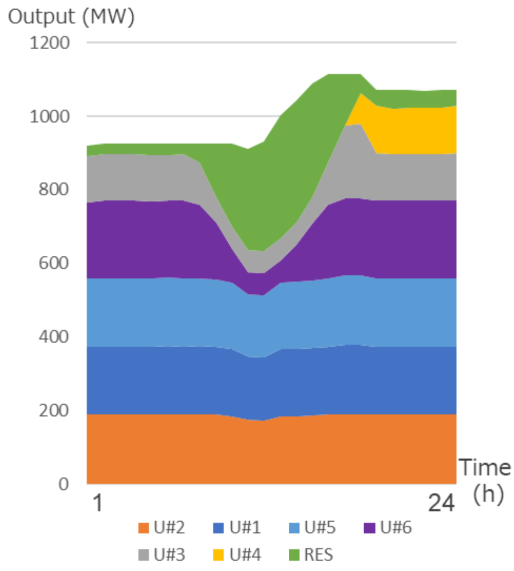


Figure 2-46 Load Curve on “Typical Day” Based on Merit Order Operation Method (left)

Figure 2-47 Load Curve on “Typical Day” Based on DSS Operation Method

Note: Calorific value of coal is 3,300kcal/kg (interview result)

Note: Unit cost of Coal is 2,000 INR/t (interview result)

Note: RES in the Figure stands for Renewable Energy Source

2.3.4 Economic performance review

According to the simulation analysis performed in 2.3.3, power distribution of each unit in 30-minute interval for each scenario was calculated. Analysis was run on one-year data, from January to December, and the fuel consumption estimated in each scenario was computated from the gross generated power obtained by the simulation. The economic performance was reviewed based on these comparisons. The results of the comparison are shown in Tables 2-10 and 2-11.

Table 2-10 Load Curve on “Typical Day” Based on Merit Order Operation Method (left)

Table 2-11 Load Curve on “Typical Day” Based on DSS Operation Method (right)

	Coal Consumption (million tons)	Fuel Cost (million INR)
Current Operation Method	5.92	11,840
【a-1】 Merit Order Operation Method	5.78	11,560

	Coal Consumption (million tons)	Fuel Cost (million INR)
Current Operation Method	5.92	11,840
【a-1】 Merit Order Operation Method	5.78	11,560

Furthermore, Table 2-12 shows the estimated results of a calculation done on the possible reduction of the coal consumption and the annual fuel cost reduction after implementing the improvement measures proposed in 2.2.3.

Table 2-12 Possible Coal Reduction and Fuel Cost Reduction after Implementing Measures

	Coal Consumption (million tons)	Fuel Cost (million INR)
【a-1】 Merit Order Operation Method	▲0.14	▲280
【b-1】 Merit Order Operation Method	▲0.03	▲60
【b-2】 DSS Operation Method	▲0.1	▲200

From the above, scenario based on (a) the track record of the demand at VSTPS in 2018, with the introduction of the merit order operation method, may lead to reduction of 140,000t/year of coal and 280million INR/year in fuel cost.

Scenario (b), which is based on the demand forecast for 2022 following the large-scale introduction of renewable energy, with the introduction of the merit order operation method, may lead to reduction of about 30,000t/year of coal, 60million INR/year in fuel cost and by additionally introducing the DSS operation method, the total reduction may reach 100,000t/year in coal volume and INR 200 million/year in fuel cost.

Chapter 7　GHG Emission Reduction Effect

7.1 Explanations to demonstrate the potential to reduce GHG emissions by implementing this strategic project and proposal on quantification of emission reductions

This Chapter examines quantification methods to estimate GHG emission reduction effect to be achieved by the measures identified by this project and then tries quantification. Strictly speaking, qualification of GHG emission reductions is possible only if the actual operational status of the power plant is properly monitored after implementing the project.　In this report, qualification will be carried out on the basis of a certain assumption about the operational status of the power plant after implementing the project.

In this project CO2 emission reductions will be achieved by reducing coal consumption.　It should be noted that the CO2 emission factor of coal here is set as 1.45t-CO2/t of coal, based on the typical calorific value (3600kcal/kg) of coal used in the power plant units which was found in the on-site survey as well as the CO2 emission factor per calorific value (26.28t-C/TJ (96.36t-CO2/TJ)) of coal used in India which was specified in India's Biennial Update Report to the United Nations Framework Convention on Climate Change[1].　In practice, the CO2 emission factor of coal should change as calorific values of coal change and also because the power plant units carry out periodic quality inspections.

This project examines the emission reduction effect by two kinds of measures: individual unit measures and optimization of the entire power plant. In this report the measures to be taken in individual units will be discussed in terms of improving efficiency (improving high-pressure turbines, etc.) and introducing more renewable energy (reducing the minimum load). As for the optimization of the entire power plant, i.e. the measures to be taken in multiple units, efficiency improvement achieved by optimal operation of multiple units will be discussed.　The two types of measures can be summarized as the following table.

Table 0-1　Summary of measures examined in this project

	Individual unit measures	Optimization of the entire power plant
Improving efficiency (Energy saving)	Increasing power generation efficiency by improving high-pressure turbine efficiency, etc.	Increasing power generation efficiency of the entire plant at a given load factor by operating higher-efficient units at a higher load during the low-load period
Improving capacity to accommodate renewable energy	Promoting accommodation of more renewables (esp. solar light during day time) by reducing the minimum load	

[1] https://unfccc.int/documents/192316

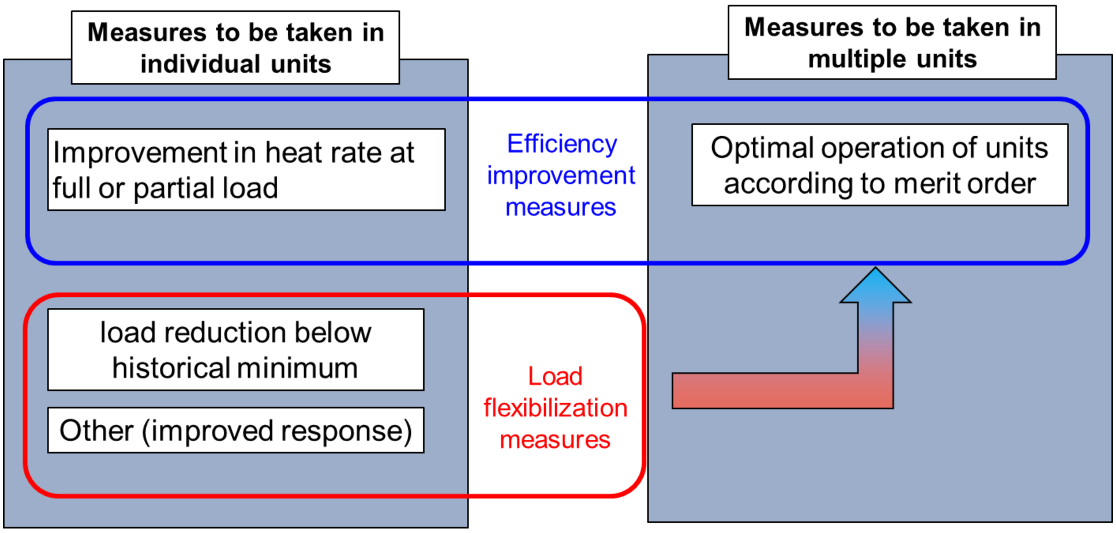


Figure 0-1 Relations of measures examined in this project

It should be noted here that to "improve the capacity to accommodate renewable energy," the power plant needs to improve the ability to adjust the output so as to accommodate more renewables. In this respect, the emission reduction effect in this project overlaps that in renewable energy projects aiming at generating and feeding power during the relevant period of time. In order for this project's reduction effect to be covered by some sort of crediting mechanism, it would be necessary to remove such overlap. To accommodate more renewables, it is important to improve load change speed (ramp up/down ability) by improving control circuit. Nevertheless, it can be interpreted that such a measure would bring about improved ability to follow the increase in renewable supply in the mornings as well as improved ability to follow the decrease in renewable supply in the evenings. It is, therefore, difficult to quantitatively assess the impact of improved load change speed on emission reductions. Power plants having a slow ramp rate could be presumed to operate conservatively in an effort to introduce renewables to meet the power demand, but they may in some cases be less conservative.

The optimization of the entire power plant, which can be achieved by "attaining a certain load factor with optimal fuel consumption (least fuel consumption) in the entire power plant," is classified in this regard as measures for efficiency improvement (energy saving). If the load factor to be attained is below the current minimum load (55%), however, it can be attained only with reducing the minimum load in individual unit measures. As such, the measures to improve efficiency and energy saving and the measures to enhance capacity to accommodate renewable energy have a certain synergy.

7.1.1 Individual power plant unit measures

(1) Improving efficiency at each power plant unit

At present various efficient improvement measures are being undertaken in India's own initiative under the Perform Achieve Trade (PAT) scheme for enhanced energy efficiency. What should be noted in calculating emission reduction effect by individual power plant unit measures is a need to separately calculate the contribution of the Japanese technologies. For this purpose, effect of relevant measures is calculated after developing a heat balance model for the power plant. The calculation flow is summarized as follows.

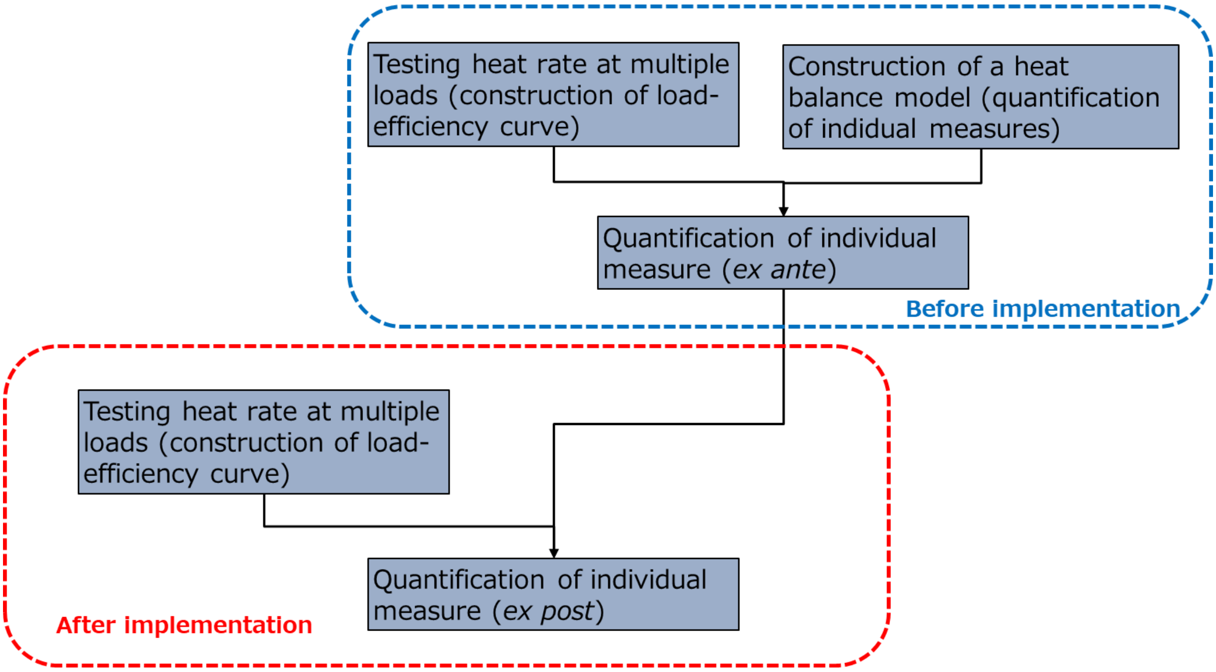


Figure 0-2 Flow of calculation of efficiency improvement at each power plant unit

(2) Reducing the minimum load

The effect of reduced minimum load postulates that renewables are introduced only for the amount of the reduction. The potential to accommodate renewables by lowering the minimum load can be calculated by multiplying the load reduction below the historical minimum (55%) by operating hours. This can be described as the following figure 7-3.

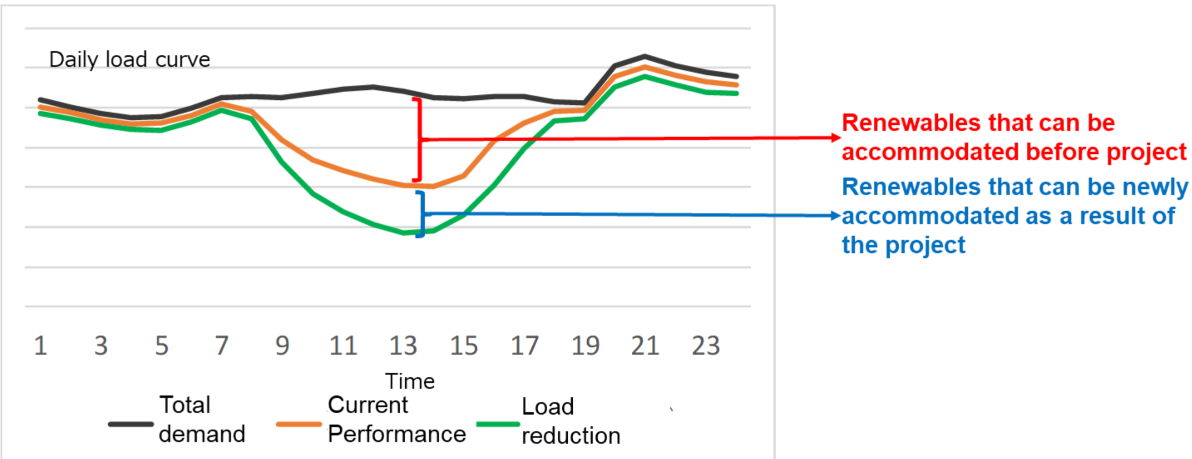


Figure 0-3 Emission reductions by lowing the minimum load

In the baseline, it is assumed that electricity is generated by the power plant units which are subjected to reduced load. CO2 emission factor is calculated based on the expected reduction of coal consumption when the load is reduced.

7.1.2 Optimizing the entire power plant

As mentioned above, the optimization of the entire power plant is achieved by adjusting the operation in a way that more efficient units are operated at a higher load, instead of all units being operated at an identical load following the dispatch instruction based on a single PPA. The emission reductions are calculated by comparing the actual fuel consumption after the optimization with the baseline fuel consumption which is based on the assumption that all units are operated at the same load as the average load of the entire plant (or of the units operated under a single PPA). This can be described as the following figure 7-4.

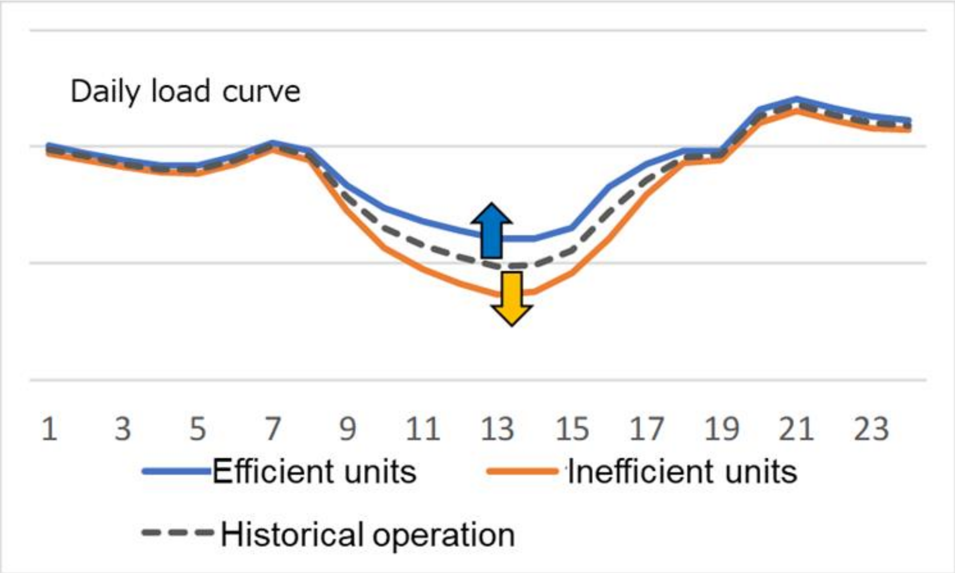


Figure 0-4 Optimization of the entire power plant

As the above calculation involves the estimated efficiency of the baseline scenario, it is desirable to make adjustment according to coal quality based on India's Perform Achieve Trade (PAT) scheme. In this project adjustment is made based on the actual coal quality.

7.1.3 Notes

(1) Preconditions, etc.

As a precondition for the success of the project, the following should be noted: in order to demonstrate the benefit of introducing the Japanese technology, it is desirable to prove that these identified measures are far more effective and feasible than ordinal measures such as regular maintenance and repair by power plants and power companies.

(2) Combining measures

Individual unit measures to reduce the minimum load and multiple unit measures to optimize the operation of the entire power plant can be demarcated as follows. Assume, for instance, that in a power plant consisting of efficient Unit A and inefficient Unit B, both of which are of the same scale, the minimum load can be lowered so as to reduce the load factor to 50% for a certain period of time. If operating the entire power plant in a way that the minimum load is reduced from 55% to 52%, effects of the following measures are expected:

- To reduce the load factor of each power plant unit below 55%
- To operate multiple units in a way to achieve optimal operation to attain a given plant load factor for the entire power plant.

The following table shows the demarcation, in terms of minimum load reduction, of individual unit measures and multiple unit measures as described above.

Table 0-2 Reducing the minimum load: demarcation of individual and multiple unit measures

Power generation efficiency improvement of Units A and B	Individual unit measures (efficiency improvement at each power plant unit)	Energy saving and accommodation of more renewables
Load reduction of efficient Unit A (55%→54%)	Individual unit measures (minimum load reduction)	Accommodation of more renewables (corresponding to 1% reduction)
Load reduction of inefficient Unit B (55%→50%)	Individual unit measures (minimum load reduction)	Accommodation of more renewables (corresponding to 5% reduction)
Load reduction of the entire power plant (55%→52%)	Total of the above	
Overall efficiency improvement of the entire power plant (Instead of operating each unit of A and B at 52%, to operate efficient Unit A at a higher load while operating inefficient Unit B at a lower load)	Optimization of the entire power plant	Energy saving

7.1.4 Outline of quantification method

Outlined below is a brief description of quantification method of GHG emission reductions based on the above. The items of quantification method conform to those of the Joint Crediting Mechanism (JCM) methodology.

(1) Eligibility criteria

- Eligible measures are those aiming at achieving the following objectives:
  - Measures contributing to efficiency enhancement of power plant equipment including boilers, turbines and auxiliaries through O&M improvement (measures for efficiency improvement)
  - Load flexibilization measures to enable reduction of the minimum load of power plant equipment
  - Measures to optimize multiple power plant units through constructing a merit order or through the Daily Start and Stop (DSS) operations.

- In addition, the above measures must fulfill the following conditions:
  - The measures must be determined by a third party other than interested parties of the power plant.
  - If the measures have negative impacts including efficiency degradation, they must be quantifiable and calculable.

(2) Implementation flow

- To carry out performance testing of the power plant under multiple load conditions before implementing the project to obtain load-efficiency curbs. The data of the most recent periodic inspection or the data used for the PAT normalization could be utilized as such load-efficiency curbs.
- To develop a heat balance model of the power plant to estimate anticipated contribution of the measures to efficiency improvement, using equipment specifications and performance testing data as appropriate.
- To carry out performance testing of the power plant under multiple load conditions after implementing the measures to obtain load-efficiency curbs.
- To calculate contribution of individual unit measures to efficiency improvement using the heat balance model and through performance testing before implementation.

(3) Calculation formulae

1) Individual unit measures

The overall efficiency of the power generation system is determined as follows.

(1) $$\eta_{T,\Delta p} = \eta_{B,\Delta p} \times \eta_{LP,\Delta p} \times \eta_{IP,\Delta p} \times \eta_{HP,\Delta p} \times \eta_{C,\Delta p}$$

Where

$\eta_{T,\Delta p}$	=	Overall efficiency during time interval Δp [dimensionless]
$\eta_{B,\Delta p}$	=	Boiler efficiency during time interval Δp [dimensionless]
$\eta_{LP,\Delta p}$	=	Low pressure turbine efficiency during time interval Δp [dimensionless]
$\eta_{IP,\Delta p}$	=	Intermediate pressure turbine efficiency during time interval Δp [dimensionless]
$\eta_{HP,\Delta p}$	=	High pressure turbine efficiency during time interval Δp [dimensionless]
$\eta_{C,\Delta p}$	=	Cycle efficiency during time interval Δp [dimensionless]

The efficiency improvement by individual unit measures is calculated as follows based on the energy audit and the heat balance model.

(2) $$\Delta\eta_{i,j,\Delta p} = \Delta\eta_{model,i,j,L\Delta p}$$

Where

$\Delta\eta_{i,j,\Delta p}$	=	Efficiency improved by Measure j contributing to efficiency improvement of Component *i* during time interval Δp [dimensionless]	Calculated with this formula

$\Delta\eta_{model,i,j,L\Delta p}$	=	Contribution of Measure *j* to efficiency improvement of Component *i* at load factor L during time interval Δp, determined with the heat balance model [%]	Calculated with the heat balance model
i	=	Classification of power plant equipment: boilers (B), low pressure turbines (LP), intermediate pressure turbines (IP), high pressure turbines (HP), cycle (C)	
j	=	Efficiency improvement measures	
L	=	Load factor of the power plant [%]	
Δp	=	Monitoring interval (timespan is relatively short, i.e. hourly, to accurately incorporate variation in PLF)	

The above parameters are set based on the energy audit performed by a third party expert before identifying measures for efficiency improvement. As for boilers, efficiency needs to be adjusted with the following adjustment factors according to the normalization process of India's Perform Achieve Trade (PAT) scheme.

(3) $$\eta_{B,corr,CQ} = (1 - \frac{\left(50\times A_{\Delta p}+630\times\left(M_{\Delta p}+9\times H_{\Delta p}\right)\right)}{GCV_{\Delta p}\times 92.5}) \times \eta_B$$

Where

$\eta_{B,corr,CQ}$	=	Boiler thermal efficiency after adjustment according to coal quality [dimensionless]	
η_B	=	Boiler thermal efficiency before adjustment [dimensionless]	Calculated with formula (2)
$A_{\Delta p}$	=	Ash content of coal used during period of time Δp [dimensionless]	Data from the power plant or coal suppliers
$M_{\Delta p}$	=	Water content of coal used during period of time Δp [dimensionless]	Same as above
$H_{\Delta p}$	=	Hydrogen content of coal used during period of time Δp [dimensionless]	Same as above
$GCV_{\Delta p}$	=	GCV of coal used during period of time Δp [dimensionless]	Same as above

If necessary and possible, it is desirable to make adjustment reflecting the age of the power plant. The formula assumed for this purpose is as follows:

(4) $$\eta_{i,corr,A} = \eta_i \times (1 - x \times r_i)$$

Where

$\eta_{i,corr,A}$	=	Component efficiency after adjustment reflecting the age [dimensionless]	Calculated with formula (4)
η_i	=	Component efficiency without adjustment [dimensionless]	Calculated with formula (2)
x	=	Years of operation	Data from the power plant
r_i	=	Annual component efficiency degradation factor [dimensionless]	Inspection data

Total improvement achieved by measures

The efficiency improvement achieved by the measures for efficiency improvement of the power plant equipment including boilers, low-, intermediate- and high-pressure turbines, and cycles is expressed as $\Delta\eta_{i,L,\Delta p}$, and as the terms of second order and above are small enough to be neglected, it is calculated as total contribution of individual unit Measure *j* ($\Delta\eta_{i,j,\Delta p}$). This can be expressed with the following equation.

(5) $$\Delta\eta_{i,\Delta p} = \sum_{j=1}^{n} \Delta\eta_{i,j,\Delta p}$$

Where

$\Delta\eta_{i,\Delta p}$	=	Equipment *i* overall efficiency improved by the measure during period of time Δp [dimensionless]	Calculated with formula (5)
$\Delta\eta_{i,j,\Delta p}$	=	Efficiency improved by Measure *j* contributing to efficiency improvement of Component *i* during time interval Δp , determined with Formula (2) [dimensionless]	Calculated with formula (2)
i	=	Classification of power plant equipment: boilers (B), low pressure turbines (LP), intermediate pressure turbines (IP), high pressure turbines (HP), cycle (C)	
j	=	Individual unit measures for efficiency improvement	

The overall efficiency improved by the measure contributing to efficiency improvement of boilers during the period of time Δp is expressed as $\Delta\eta_{B,\Delta p}$. The contribution to overall efficiency improvement amounting to $\Delta\eta_{i,\Delta p}$. is approximately expressed as follows:

(6) $$\Delta\eta_{B,\Delta p} \times (\eta_{LP,\Delta p} \times \eta_{IP,\Delta p} \times \eta_{HP,\Delta p} \times \eta_{C,\Delta p}) = \eta_{T,\Delta p} \times \frac{\Delta\eta_{B,\Delta p}}{\eta_{B,\Delta p}}$$

Where

$\Delta\eta_{B,\Delta p}$	=	Degree of boiler efficiency improvement during time interval Δp [dimensionless]
$\eta_{T,\Delta p}$	=	Overall efficiency during time interval Δp [dimensionless]
$\eta_{B,\Delta p}$	=	Boiler efficiency during time interval Δp [dimensionless]
$\eta_{LP,\Delta p}$	=	Low pressure turbine efficiency during time interval Δp [dimensionless]
$\eta_{IP,\Delta p}$	=	Intermediate pressure turbine efficiency during time interval Δp [dimensionless]
$\eta_{HP,\Delta p}$	=	High pressure turbine efficiency during time interval Δp [dimensionless]

The efficiency of each component before implementing the measures is calculated according to the heat balance model.

Based on the above, the degree of overall efficiency improvement of all equipment is calculated as follows:

(7) $$\Delta\eta_{T,\Delta p} = \eta_{T,\Delta p,BL} \times \left(\frac{\Delta\eta_{B,\Delta p}}{\eta_{B,\Delta p}} + \frac{\Delta\eta_{LP,\Delta p}}{\eta_{LP,\Delta p}} + \frac{\Delta\eta_{IP,\Delta p}}{\eta_{IP,\Delta p}} + \frac{\Delta\eta_{HP,\Delta p}}{\eta_{HP,\Delta p}} + \frac{\Delta\eta_{C,\Delta p,}}{\eta_{C,\Delta p}}\right)$$

Where

$\Delta\eta_{T,\Delta p}$	=	Overall efficiency improved during time interval Δp [dimensionless]
$\Delta\eta_{B,\Delta p}$	=	Boiler efficiency improved during time interval Δp [dimensionless]
$\Delta\eta_{LP,\Delta p}$	=	Low pressure turbine efficiency improved during time interval Δp [dimensionless]
$\Delta\eta_{IP,\Delta p}$	=	Intermediate pressure turbine efficiency improved during time interval Δp [dimensionless]
$\Delta\eta_{HP,\Delta p}$	=	High pressure turbine efficiency improved during time interval Δp [dimensionless]

(The second-order terms are very small and negligible.)

Thus the rate of overall efficiency improvement is calculated by multiplying the relative improvement degree of each component by overall efficiency.

Accordingly the amount of energy savings is calculated as follows:

(8) $$EC_{\Delta p} = 3.6 \times EG_{\Delta p} \times \left(\frac{1}{\eta_{T,\Delta p,BL}} - \frac{1}{\eta_{T,\Delta p} + \Delta\eta_{T,p}}\right) = 3.6 \times EG_{\Delta p} \times \frac{\Delta\eta_{T,,\Delta p}}{(\eta_{T,\Delta p,BL})(\eta_{T,\Delta p} + \Delta\eta_{T,,\Delta p})}$$

Where

$EC_{\Delta p}$	=	Amount of energy saved during time interval Δp [TJ]	Calculated with formula (8)
$EG_{\Delta p}$	=	Power production during time interval Δp [GWh]	Monitoring data
$\Delta\eta_{T,\Delta p}$	=	Overall efficiency improved during time interval Δp [dimensionless]	Calculated with formula

			(7)
$\eta_{T,\Delta p}$	=	Overall efficiency during time interval Δp before implementing the measure [dimensionless]	Calculated with the heat balance model

And

(9) $$ER_{eff,\Delta p} = EC_{\Delta p} \times NCV_{coal} \times EF_{coal}$$

Where

$ER_{eff,\Delta p}$	=	Emission reduced by efficiency improvement measures during time interval Δp [t-CO2]	Calculated with formula (9)
$EC_{\Delta p}$	=	Amount of energy saved during time interval Δp [TJ]	Calculated with formula (8)
NCV_{coal}	=	NCV of coal [TJ/tonne]	Data from the power plant or coal suppliers
EF_{coal}	=	CO2 emission factor of coal [t-CO2/TJ]	IPCC 2006GL or national data

2) Reducing the minimum load

The load flexibilization measures are carried out with the aim of responding to variance in generation by renewable energy. Therefore it should be noted that the calculated amount of emissions reduced by the load flexibilization measures can be interpreted as those achieved by renewable energy generators.

The amount of emissions reduced can be calculated as follows, taking into account a possible increase in fuel consumption of auxiliaries due to reduction of the minimum load.

(10) $$ER_{lf,\Delta p} = \max(CAP_i \times (L_{hist,min} - L_{i,\Delta p}), 0) \times \Delta_p \times \frac{3.6}{\eta_{T,,\Delta p}} \times NCV_{coal} \times EF_{coal} - \max(FC_{AUX,\Delta p} - FC_{AUX,PLFhistmin}, 0) \times NCV_{aux} \times EF_{aux}$$

Where

$ER_{lf,\Delta p}$	=	Emissions reduced by load flexibillization measures during time interval Δp [t-CO2]	Calculated with formula (10)
CAP_i	=	Installed capacity of Equipment i [MW]	Data from the power plant
$L_{hist,min}$	=	Historical minimum plant load factor. Unscheduled non-operating time due to equipment failure, short supply of coal, etc. excluded. [=0.55: dimensionless]	Data from the power plant
$L_{i,\Delta p}$	=	Plant load factor during time interval Δp [dimensionless]	Monitoring data
$\eta_{T,\Delta p}$	=	Overall efficiency during time interval Δp [dimensionless]	Monitoring data or test data during load reduction test
NCV_{coal}	=	NCV of coal [TJ/tonne]	Data from the power plant or coal suppliers
EF_{coal}	=	CO2 emission factor of coal [t-CO2/tonne]	IPCC 2006GL or national data
$FC_{AUX,\Delta p}$	=	Fuel consumption of auxiliaries during time interval Δp [mass or volume unit]	Monitoring data
$FC_{AUX,PLF\mathrm{histmin}}$	=	Fuel consumption of auxiliaries at the historical minimum plant load factor. Unscheduled non-operating time due to equipment failure, short supply of coal, etc. excluded.	Data from the power plant
NCV_{aux}	=	NCV of fuel for auxiliaries [TJ/mass or volume unit]	Data from the power plant or coal suppliers
EF_{aix}	=	CO2 emission factor of fuel for auxiliaries [t-CO2/TJ]	IPCC 2006GL or

national data

3) Optimizing the entire power plant

The optimization measure of the entire power plant can contribute to emission reductions. The amount of emissions reduced by optimizing the entire power plant through constructing a merit order or through the Daily Start and Stop (DSS) operations is calculated by subtracting emissions reduced by optimizing individual equipment as shown in the previous Chapter from emissions reduced in the entire power plant, taking into consideration the historical operational status of individual power plant units based on their plant load factors (PLF). In particular with regard to DSS, possible additional consumption of supplemental fuel in case of hot start-up is taken into account.

The basic formulae are as follows:

(11) $$BE_{S,\Delta p} = \frac{EG_{S,\Delta p}}{\eta_{S,L\Delta phist}} \times ADJ_{coal,\Delta p} \times 3.6 \times EF_{fuel}$$

(12) $$PE_{\mathrm{S},\Delta p} = FC_{\mathrm{S},\Delta p} \times NCV_{fuel} \times EF_{fuel}$$

(13) $$ER_{\mathrm{S},\Delta p} = BE_{\mathrm{S},\Delta p} - PE_{\mathrm{S},\Delta p}$$

(14) $$ER_{S,p} = \sum_{\Delta \mathrm{p}}(ER_{\mathrm{S},\Delta p} - \sum_i ER_{i,\Delta p})$$

Where

$BE_{\mathrm{S},\Delta p}$	=	Baseline emissions of the entire power plant during period of time Δp (t-CO2)	Calculated with formula (11)
$EG_{\mathrm{S},\Delta p}$	=	Power production of the entire power plant during period of time Δp (GWh)	Monitoring data
$\eta_{\mathrm{S,L}\Delta p,\mathrm{hist}}$	=	Historical power generation efficiency of the entire power plant at load factor L during period of time Δp	Calculated based on historical data or simulation
EF_{fuel}	=	CO2 emission factor of fuel used (t-CO2/TJ)	Data from the power plant
$ADJ_{coal,\Delta p}$	=	Adjustment according to coal quality	See the following (formula (15))
$PE_{\mathrm{S},\Delta p}$	=	Project emissions of the entire power plant during period of time Δp (t-CO2)	Calculated with formula (12)
$FC_{\mathrm{S},\Delta p}$	=	Fuel consumption of the entire power plant during period of time Δp (mass or volume unit)	Monitoring data
NCV_{fuel}	=	Net calorific value of fuel used (TJ/mass or volume unit)	Data from the power plant
$ER_{\mathrm{S},\Delta p}$	=	Emissions reduced in the entire Power Plant *i* during period of time Δp (t-CO2)	Calculated with formula (13)
$ER_{S,p}$	=	Emissions reduced in the entire power plant during period of time *p* (t-CO2)	Calculated with formula (14)
$ER_{i,p}$	=	Emissions reduced of Equipment *i* during period of time *p* (t-CO2)	Calculated based on the previous Chapter
Δp	=	Monitoring interval (timespan is relatively short, i.e. hourly, to accurately incorporate variation in PLF)	-
p	=	Time period for calculation (e.g. one year)	-
i	=	Identifier of a power generating equipment	-

Adjustment according to the quality of coal

As the quality of coal used in the past may possibly be different from the quality of coal currently used, adjustment is made according to the coal quality. Adjustment can be expressed as follows, applying the PAT normalization method as described above.

$$(15) \qquad ADJ_{coal,\Delta p} = \frac{92.5 - \frac{(50 \times A_{hist} + 630 \times (M_{hist} + 9 \times H_{hist}))}{GCV_{hist}}}{92.5 - \frac{(50 \times A_{\Delta p} + 630 \times (M_{\Delta p} + 9 \times H_{\Delta p}))}{GCV_{\Delta p}}}$$

Where

Parameter	Outline	Calculation method
$ADJ_{coal,\Delta p}$	Adjustment according to coal quality	Calculated with this method
A_{hist}	Ash content of coal used during a certain period of time in the past (%)	Data from the power plant or coal suppliers
M_{hist}	Water content of coal used during a certain period of time in the past (%)	Same as above
H_{hist}	Hydrogen content of coal used during a certain period of time in the past (%)	Same as above
GCV_{hist}	GCV of coal used during a certain period of time in the past (%)	Same as above
$A_{\Delta p}$	Ash content of coal used during period of time Δp (%)	Data from the power plant or coal suppliers
$M_{\Delta p}$	Water content of coal used during period of time Δp (	Same as above
$H_{\Delta p}$	Hydrogen content of coal used during period of time Δp (	Same as above
$GCV_{\Delta p}$	GCV of coal used during period of time Δp (	Same as above

The period of time considered as a certain period of time in the past (hist) is not precisely defined here, but it is desirable that it should conform to historical data.

4) Notes

The two types of emission reductions, namely $ER_{i,\Delta p}$ and $ER_{S,\Delta p}$, partially overlap with each other as they are not mutually exclusive. In case of implementing both the measures at the same time, the effect of $ER_{i,\Delta p}$ must be subtracted from $ER_{S,\Delta p}$.

Due to statistical uncertainty, $ER_{S,p}$ might be calculated to be a negative value in some cases. Therefore it is desirable to set the minimum value of $ER_{S,\Delta p}$and $ER_{S,p}$ to zero as below. This is because individual unit measures are not considered to contribute to an increase in emissions.

$$ER_{i,p} = min(\sum_{\Delta p} ER_{i,\Delta p}, 0)$$

$$ER_{S,p} = min(\sum_{\Delta p} (ER_{S,\Delta p} - \sum_{i} ER_{i,\Delta p}),0)$$

In several CDM methodologies, emission reductions are not utilized for compliance purposes. It is probably not necessary, therefore, to take account of the maximum values of $ER_{S,\Delta p}$and $ER_{S,p}$.

7.2 Estimation of GHG emission reduction and control effects after dissemination, based on the proposed quantification method

Here an estimation is made as to the GHG emission reduction and control effects after dissemination, applying the method examined in the previous Chapter. However since monitoring has not been carried out before implementing the project, estimated approximate values are used for some of the parameters to be monitored ex post.

7.2.1 Individual unit measures

(1) Improving the power generation efficiency

As discussed above, individual unit measures include, specifically, measures for emission reductions through control improvement and turbine efficiency recovery. These measures are expected to contribute to increasing the power generation efficiency and reducing CO2 emissions. As shown in Chapter 2.2.3, by conducting the on-site survey of the power plant as well as by developing a heat balance model as a part of this project, the overall efficiency is expected to increase from 34.7% to 35.05%. Assuming the baseload operation scenario (plant load factor of 98%) of Vindhyachal Thermal Power Station, coal savings are estimated at approx. 28 ktonnes (approx. 41 ktonnes of CO2-equivalent).

Also as shown in Chapter 2.2.3, if appropriate maintenance of each equipment other than the above is undertaken and the turbine efficiency returns to their design efficiency level, the overall efficiency would recover up to 37.51%. In this case the potential coal savings are estimated at approx. 219 ktonnes (approx. 318 ktonnes of CO2-equivalent).

If the introduction of renewable energy rapidly accelerates and the load factor decreases by means of reducing the minimum load, etc., GHG emission reductions due to efficiency improvement will change mostly in proportion to changes in plant load factors.

(2) Reducing the minimum load

By the measures to reduce the minimum load, the load factor is expected to decrease from the historical minimum of 55% to 50%. For example, if implementing such reduction in a unit of 500MW, the minimum load decreases from 275MW to 250MW, making it possible to accommodate additional 25MW of renewables (particularly solar). Assuming that the minimum load has been reduced for 2,349 hours (261 days x 9 hours), then additional 60GWh of renewables (especially solar) can be accommodated.

The estimated fuel consumption rate at this time is extrapolated to be 185.2tph, based on the findings of the on-site survey of the power plant which showed that the fuel consumption rates of 375MW and 275Mw were 240.4tph and 196.2tph respectively.

In other words, a reduction in coal consumption of 26 ktonnes would allow for accommodation of additional 60GWh of renewables (especially solar) and also would bring a corresponding amount of CO2 emission reductions (approx. 38 ktonnes of CO2-equivalent). As mentioned above, however, such reductions cannot be achieved without introduction of renewable energy as individual unit measures for emission reductions. Therefore if any emission reductions are claimed by renewable energy generators, they correspond to the same emission reductions achieved by load reduction.

7.2.2 Optimizing the entire power plant

Stage 1 of Vindhyachal Thermal Power Station consists of six units of 210MW each and they are under a single PPA. Therefore Stage 1 is suitable for estimating the optimization effect of the entire power plant. As discussed in Chapter 2.3, a simulation was performed in Stage 1 in order to assess the optimization effect. As a result, it was estimated that if applying the approach of operating more efficient power plant units at a higher load according to the developed merit order, the amount of coal reduced based on the presumed introduction rate of renewable energy in 2022 would amount to approx. 30 ktonnes (approx. 44 ktonnes of GHG emission reductions). In addition, if implementing the Daily Start and Stop (DSS) operations where the operation of inefficient power plant units is completely stopped, the amount of coal reduced are estimated at approx. 100 ktonnes (approx. 145 ktonnes of GHG emission reductions).